American Electric Power

2025 Annual Report

Audited Consolidated Financial Statements and
Management's Discussion and Analysis of Financial Condition and Results of Operations

AMERICAN ELECTRIC POWER®
BOUNDLESS ENERGY℠

CONTENTS

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GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated VIE of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP Development Services, LLC	AEP Development Services, LLC, a consolidated VIE of AEP formed for the purpose of developing, constructing, and installing energy projects for the regulated operating companies of AEP.
AEP East Companies	APCo, I&M, KGPCo, KPCo, OPCo and WPCo.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
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 Renewables	A former division of AEP Energy Supply, LLC that develops and/or acquires large scale renewable projects that are backed with long-term contracts with creditworthy counter parties.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary. AEP 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.
APSC	Arkansas Public Service Commission.
APTCo	AEP Appalachian Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
ATM	At-the-Market.
BESS	Battery Energy Storage System.

Term	Meaning
BHE	Berkshire Hathaway Energy.
CAA	Clean Air Act.
CAMT	Corporate Alternative Minimum Tax.
CCN	Certificate of Convenience and Necessity.
CCR	Coal Combustion Residual.
CEO	Chief Executive Officer.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
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.
CPCN	Certificate of Public Convenience and Necessity.
CRES Provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CSAPR	Cross-State Air Pollution Rule.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
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.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo. DHLC is a non-consolidated VIE of SWEPCo.
DIR	Distribution Investment Rider.
Diversion	Diversion, acquired in December 2024, consists of 201 MWs of wind generation in Texas.
DOE	U. S. Department of Energy.
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.
Equity Units	AEP's Equity Units issued in August 2020 and March 2019.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Transmission Holdco and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
Excess ADIT	Excess Accumulated Deferred Income Taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or Scrubbers.
FIP	Federal Implementation Plan.

Term	Meaning
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.
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.
IRA	On August 16, 2022 President Biden signed into law legislation commonly referred to as the "Inflation Reduction Act" (IRA).
IRC	Internal Revenue Code.
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.
KTCo	AEP Kentucky Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
kV	Kilovolt.
KWh	Kilowatt-hour.
Liberty	Liberty Utilities Co., a subsidiary of Algonquin Power & Utilities Corporation.
LPSC	Louisiana Public Service Commission.
MATS	Mercury and Air Toxic Standards.
Maverick	Maverick, part of the North Central Wind Energy Facilities, consists of 287 MWs of wind generation in Oklahoma.
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.
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.
NERC	North American Electric Reliability Corporation.
NMRD	New Mexico Renewable Development, LLC.

Term	Meaning
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NOL	Net Operating Losses.
NOLC	Net Operating Loss Carryforward.
NO_x	Nitrogen Oxide.
NRC	Nuclear Regulatory Commission.
OATT	Open Access Transmission Tariff.
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.
OKTCo	AEP Oklahoma Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
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.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third-party sales. AEPSC acts as the agent.
OTC	Over-the-counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PATH-WV	PATH West Virginia Transmission Company, LLC, a joint venture-owned 50% by FirstEnergy and 50% by AEP.
PBA	Performance Based Accreditation.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
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.
REP	Texas Retail Electric Provider.
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.

Term	Meaning
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.
Sundance	Sundance, acquired in April 2021 as part of the North Central Wind Energy Facilities, consists of 199 MWs of wind generation in Oklahoma.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary. SWEPCo engages in the generation, transmission and distribution of electric power to retail customers in northeastern and panhandle of Texas, northwestern Louisiana and western Arkansas.
SWTCo	AEP Southwestern Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
TA	Transmission Agreement, effective November 2010, among APCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the “Tax Cuts and Jobs Act” (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
TCA	Transmission Coordination Agreement dated January 1, 1997, by and among, PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two public utility subsidiaries.
T&D	Transmission and Distribution Utilities.
TPUC	Tennessee Public Utilities Commission.
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 AEPTHCo.
Traverse	Traverse, part of the North Central Wind Energy Facilities, consists of 998 MWs of wind generation in Oklahoma.
Turk Plant	John W. Turk, Jr. Plant, a 650 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UMWA	United Mine Workers of America.
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.
Valley Link	Valley Link Transmission Company, LLC, a holding company formed by Transource Energy, affiliates of Dominion Energy and FirstEnergy in 2024, which is 31.14% owned by AEP.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
VIU	Vertically Integrated Utilities.

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

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 "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations," but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, management undertakes no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Changes in economic conditions, electric market demand and demographic patterns in AEP service territories.
- The economic impact of increased global conflicts and trade tensions, and the adoption or expansion of economic sanctions, tariffs, trade restrictions or changes in trade policy.
- Inflationary or deflationary interest rate trends.
- New legislation 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 disruptions in financial markets precipitated by any cause, including fiscal and monetary policy or instability in the banking industry; particularly developments affecting the availability or cost of capital to finance new capital projects and refinance existing debt.
- The availability and cost of funds to finance working capital and capital needs, particularly (a) if expected sources of capital such as proceeds from the sale of 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 build or acquire generation (including from renewable sources and battery storage), transmission lines and facilities (including the ability to obtain any necessary regulatory approvals and permits) to meet the demand for electricity at acceptable prices and terms, including favorable tax treatment, cost caps imposed by regulators and other operational commitments to regulatory commissions and customers for generation projects, to recover all related costs and to earn a reasonable return.
- The disruption of AEP's business operations due to impacts of economic or market conditions, costs of compliance with potential government regulations, electricity usage, supply chain issues, customers, service providers, vendors and suppliers caused by 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.
- Prolonged or recurring U.S. federal government shutdowns could adversely affect AEP's operations, regulatory approvals, and financial performance and could cause 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.

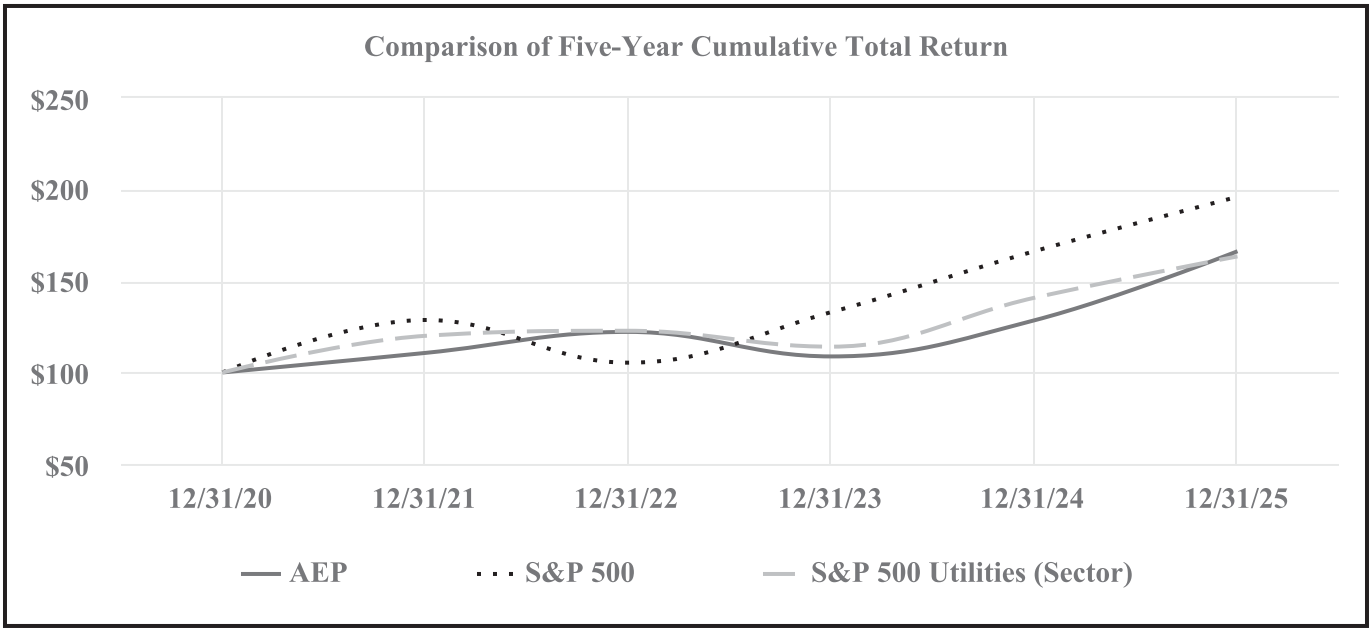
- The impact of tax legislation or associated Department of Treasury guidance, including potential changes to existing tax incentives, on capital plans, results of operations, financial condition, cash flows or credit ratings.
- The risks before, during and after generation of electricity associated 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 and the allocation of costs within RTOs including ERCOT, PJM and SPP and the impacts of potential market changes 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 issuer ratings impacting the cost of debt.
- The impact of volatility in the capital markets on the value of the investments held by the pension, OPEB and nuclear decommissioning trust funds and a captive insurance entity and the impact of such volatility on future funding requirements.
- Accounting standards periodically issued by accounting standard-setting bodies.
- 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.

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 this report. The disclosures in this section reflect AEP’s beliefs and opinions as to factors that could materially and adversely affect AEP in the future. References to past events are provided by way of example only and are not intended to be a complete listing or a representation as to whether or not such factors have occurred in the past or their likelihood of occurring in the future.

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/.

AEP COMMON STOCK INFORMATION

AEP common stock is principally traded using the trading symbol "AEP" on the NASDAQ Stock Market. As of December 31, 2025, AEP had 42,604 registered shareholders. The performance graph below compares the cumulative total return among AEP, the S&P 500 Index and the S&P 500 Utilities (Sector) Index over a five year period. The performance graph assumes an initial investment of $100 on December 31, 2020 and that all dividends were reinvested.



Past performance is no guarantee of future results. Chart provided for illustrative purposes.

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

EXECUTIVE OVERVIEW

Company Overview

AEP is one of the largest investor-owned electric public utility holding companies in the United States. AEP's electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

AEP's subsidiaries operate an extensive portfolio of assets including:

- Approximately 252,000 circuit miles of distribution lines.
- Approximately 38,000 circuit miles of transmission lines, including approximately 2,000 circuit miles of 765 kV lines.
- Approximately 25,000 MWs of regulated owned generating capacity as of December 31, 2025.

AEP is committed to executing its strategy to improve customers' lives with reliable, affordable power. AEP's mission is to put the customer first and is focused on six core principles:

- Customer Service - Industry-best customer experience.
- Employee Commitment - Safe and secure workplace; engaged, trained and developed employees.
- Environmental Respect - Creative sustainable energy solutions.
- Regulatory & Legislative Integrity - Balanced regulatory outcomes; Trusted industry leadership.
- Operational Excellence - World-class asset performance.
- Financial Strength - Strong financial discipline.

AEP CONSOLIDATED RESULTS OF OPERATIONS

2025 Compared to 2024

Earnings Attributable to AEP Common Shareholders increased from $3.0 billion in 2024 to $3.6 billion in 2025 primarily due to:

- Investment in transmission assets, which resulted in higher revenues and income.
- The favorable impact from the receipt of the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- A revenue refund provision recorded in 2024 associated with the Turk Plant and SWEPCo's 2012 Texas Base Rate Case.
- A decrease in operating expense due to the Federal EPA's revised CCR rule which resulted in higher operating expenses in 2024.
- A decrease in operating expenses due to the voluntary severance program that occurred in the second quarter of 2024.
- An increase in sales volumes driven by favorable weather.
- Favorable rate proceedings in AEP's various jurisdictions.

These increases were partially offset by:

- The favorable impact from the receipt of PLRs in 2024 related to the treatment of NOLCs in retail ratemaking. See "NOLCs in Retail Jurisdictions - IRS PLRs" section below for additional information.
- An increase in operating expenses recorded in 2025 due to an impairment of in-process internal use software development costs.

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

Non-GAAP Financial Measures

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

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

Reconciliation of Reported GAAP Earnings to Operating Earnings

The following table presents a reconciliation of operating earnings to the most directly comparable GAAP measure.

	Year Ended December 31, 2025							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Reported GAAP Earnings	$ 3,580	$ 488	$ 1,075	$ 457	$ 414	$ 328	$ 252	$ 388
Adjustments to Reported GAAP Earnings (a):								
Mark-to-Market Impact of Commodity Hedging Activities (b)	9	—	—	—	7	—	—	—
Sale of AEP OnSite Partners (c)	10	—	—	—	—	—	—	—
Impact of Ohio Legislation (d)	19	—	—	—	—	19	—	—
FERC NOLC Order (e)	(480)	—	(354)	(29)	(36)	—	(4)	(54)
Impairment of Software Development Costs (f)	52	11	—	9	7	14	5	4
Total Specified Items	(390)	11	(354)	(20)	(22)	33	1	(50)
Operating Earnings	$ 3,190	$ 499	$ 721	$ 437	$ 392	$ 361	$ 253	$ 338

(a) Excluding tax related adjustments, all items presented in the table are tax adjusted at the statutory rate unless otherwise noted.
(b) Represents the impact of mark-to-market economic hedging activities.
(c) Represents an adjustment to the estimated loss on the sale of AEP OnSite Partners as a result of the contractual working capital true-up.
(d) Represents the reduction in regulatory assets for OVEC-related purchased power costs as a result of approved legislation in Ohio in April 2025.
(e) Represents the impact of the FERC NOLC Order for years 2021-2024.
(f) Represents an impairment of in-process internal use software development costs.

	Year Ended December 31, 2024							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Reported GAAP Earnings	$ 2,967	$ 420	$ 688	$ 422	$ 391	$ 306	$ 249	$ 321
Adjustments to Reported GAAP Earnings (a):								
Mark-to-Market Impact of Commodity Hedging Activities (b)	(85)	—	—	—	19	—	—	—
Remeasurement of Excess ADIT Regulatory Liability (c)	(45)	—	—	—	(12)	—	—	(33)
Impact of NOLC on Retail Ratemaking (d)	(260)	—	—	—	(69)	—	(57)	(134)
Disallowance - Dolet Hills Power Station (e)	11	—	—	—	—	—	—	11
Provision for Refund - Turk Plant (f)	117	—	—	—	—	—	—	117
Sale of AEP OnSite Partners (g)	11	—	—	—	—	—	—	—
Severance and Pension Settlement Charges (h)	121	16	9	20	17	19	8	23
Federal EPA CCR Rule (i)	111	—	—	—	11	41	—	—
SEC Matter Loss Contingency (j)	19	—	—	—	—	—	—	—
State Tax Law Changes (k)	11	—	—	—	—	—	—	11
Total Specified Items	11	16	9	20	(34)	60	(49)	(5)
Operating Earnings	$ 2,978	$ 436	$ 697	$ 442	$ 357	$ 366	$ 200	$ 316

(a) Excluding tax related adjustments, all items presented in the table are tax adjusted at the statutory rate unless otherwise noted.
(b) Represents the impact of mark-to-market economic hedging activities.
(c) Represents the impact of the remeasurement of Excess ADIT in Arkansas and Michigan as a result of the denial of SWEPCo's request regarding the Turk Plant by the APSC and the approved treatment of stand-alone NOLCs by the MPSC.
(d) Represents the impact of receiving IRS PLRs related to NOLCs in retail ratemaking on I&M, PSO and SWEPCo. Amount includes a reduction in Excess ADIT and activity related to prior periods.
(e) Represents the impact of a disallowance recorded at SWEPCo on the remaining net book value of the Dolet Hills Power Station as a result of an LPSC approved settlement agreement in April 2024.
(f) Represents a provision for revenue refunds on certain capitalized costs associated with the Turk Plant.
(g) Represents the loss on the sale of AEP OnSite Partners.
(h) Represents employee severance charges and pension settlement expenses.
(i) Represents the impact of the Federal EPA Revised CCR Rule.
(j) Represents an estimated loss contingency related to a previously disclosed SEC investigation.
(k) Represents the impact of the remeasurement of ADIT as a result of enacted state tax legislation in Arkansas and Louisiana.

	Year Ended December 31, 2023							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Reported GAAP Earnings	$ 2,208	$ 370	$ 614	$ 294	$ 336	$ 328	$ 209	$ 220
Adjustments to Reported GAAP Earnings (a):								
Mark-to-Market Impact of Commodity Hedging Activities (b)	228	—	—	—	(20)	—	—	—
Remeasurement of Excess ADIT Regulatory Liability (c)	(46)	—	—	(46)	—	—	—	—
ENEC Fuel Disallowance (d)	181	—	—	101	—	—	—	—
Turk Impairment (e)	80	—	—	—	—	—	—	80
Sale of Unregulated Renewables (f)	73	—	—	—	—	—	—	—
Kentucky Operations (g)	(34)	—	—	—	—	—	—	—
Change in Texas Legislation (h)	(24)	(20)	—	—	—	—	—	(4)
FERC NOLC Disallowance (i)	24	—	36	(4)	(2)	(9)	(3)	1
Severance Charges (j)	19	3	1	4	3	5	1	2
Impairment of Investment in NMRD (k)	15	—	—	—	—	—	—	—
Total Specified Items	516	(17)	37	55	(19)	(4)	(2)	79
Operating Earnings	$ 2,724	$ 353	$ 651	$ 349	$ 317	$ 324	$ 207	$ 299

(a) Excluding tax related adjustments, all items presented in the table are tax adjusted at the statutory rate unless otherwise noted.
(b) Represents the impact of mark-to-market economic hedging activities.
(c) Represents the impact of the remeasurement of ADIT - NOLC in Virginia and West Virginia.
(d) Represents the impact of the disallowance of the recovery of certain deferred fuel costs in West Virginia.
(e) Represents the impact of the disallowance of certain capitalized costs associated with the Turk Plant.
(f) Represents the loss on the sale of the Competitive Contracted Renewable Portfolio and other related third-party transaction costs.
(g) Represents an adjustment to the loss on the expected sale of the Kentucky Operations which was terminated in April 2023 and other related third-party transaction costs.
(h) Represents the impact of recent legislation in Texas regarding recovery of certain employee incentives.
(i) Represents the impact of the FERC decision denying stand-alone treatment of NOLCs for transmission formula rates.
(j) Represents the impact of AEP's workforce reduction in 2023.
(k) Represents the impairment of AEP's investment in the NMRD joint venture.

ELECTRIC INDUSTRY TRANSFORMATION

The electric utility industry is undergoing a historic transformation, fueled by rapid commercial customer class 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 the system peak demand by 2030 across its diversified service territory, with especially strong projected growth in Indiana, Ohio, Oklahoma and Texas. To meet this accelerating demand, AEP outlined a $72 billion, five year capital plan focused on strengthening transmission infrastructure, adding new generation resources to serve both existing customers and large forecasted 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.

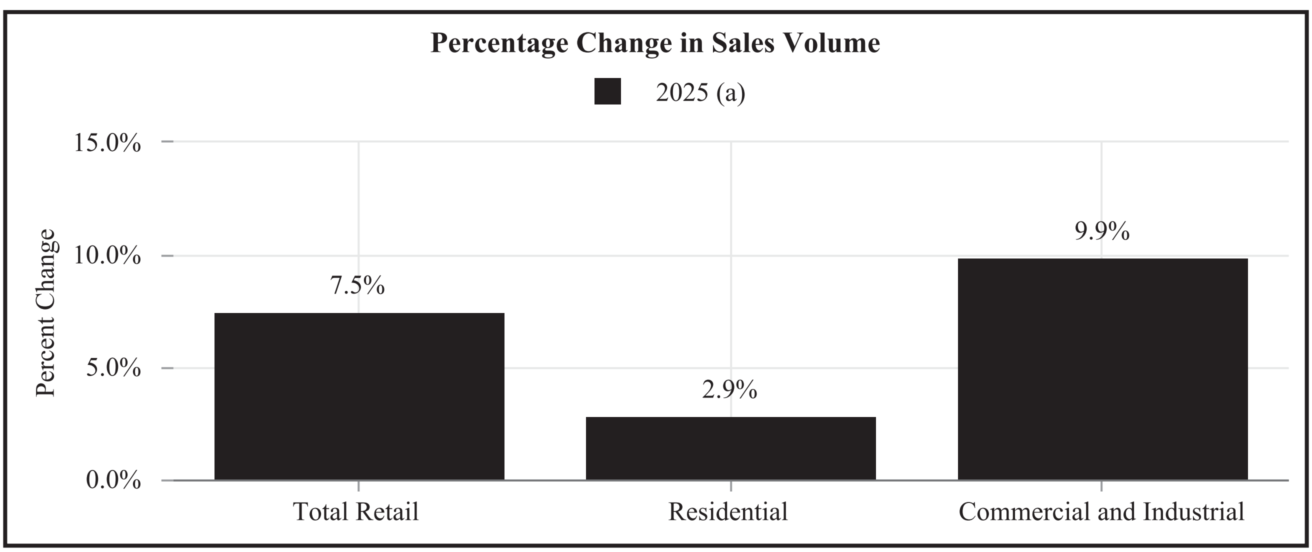
AEP has advanced large-load tariff proposals and tariff modifications aimed at enabling the rapid interconnection of committed large load customers while protecting existing customers from increased costs. These proposals have been filed in eight of AEP's jurisdictions, with four already approved by state commissions. AEP is actively engaging with regulators, policymakers, RTOs, customers and suppliers to advance system reliability, resiliency and affordability across its service territories during this period of rapid transformation.

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

- The addition of 2.2 GWs of owned generating capacity in 2025.
- Securing additional turbines for gas-fired turbine capacity.
- RFPs seeking approximately 12,700 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.

Customer Demand

AEP uses sales volumes by customer class as a way to measure drivers of customer demand. In 2025, AEP experienced an increase in customer demand for power driven primarily by new data processing loads coming online in 2025 in the commercial customer class and favorable weather and marginal growth in the residential class. The table below shows the percentage change in sales volume by customer class.



(a) Percentage change for the year ended December 31, 2025 as compared to the year ended December 31, 2024. Load figures are billed retail sales excluding firm wholesale load.

Large Load/Data Center Tariffs

Several AEP utility subsidiaries have made rate filings with state commissions to establish new tariffs for data centers and other large load customers. 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 90% of their contracted demand. In practice, these provisions reduce risks around the build out of large load infrastructure on existing customers, promoting stability and affordability. The table below provides a summary of the status of these new data center and large load tariffs.

Company	Jurisdiction	Large Load Tariff	Status (a)	Customer Eligibility
APCo	Virginia	Large Power Service	Pending	New load of 150 MWs or more/100 MWs for individual site
APCo	West Virginia	Large Capacity/Industrial Power	Approved	New load of 150 MWs or more/100 MWs for individual site
I&M	Indiana	Industrial Power	Approved	New load of 150 MWs or more/70 MWs for individual site
I&M	Michigan	Large Load	Pending	New load of 50 MWs or more
KPCo	Kentucky	Industrial General Service	Approved	New commercial or industrial load of 150 MWs or more
OPCo	Ohio	Data Center	Approved	New data center load of 25 MWs or more
PSO	Oklahoma	Large Power and Light	Pending	New load of 75 MWs or more
SWEPCo	Texas	Electric Service Large Load	Pending	New load of 75 MWs or more

(a) Both the pending and the approved tariffs include certain requirements for cash, or cash related instruments, as deposits.

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 way that supports business development in Texas while minimizing 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 is currently drafting rules through multiple active dockets related to large load interconnection standards, net-metering arrangements for co-location, large load forecasting criteria, large load reliability/demand reduction and transmission cost allocation review to implement SB 6. The rulemaking projects are on various timelines, with final adoptions planned throughout 2026. AEP Texas has signed Letters of Agreement for an incremental 36 gigawatts of load by 2030. As the PUCT finalizes its SB 6 rulemaking efforts, AEP Texas expects improved clarity and certainty around the timing and the amount of additional load connection in ERCOT.

PJM Capacity Market Reform

The AEP East Companies are members of PJM. Utilities in PJM can meet their capacity obligations by either: (a) participating in capacity auctions administered by PJM, or (b) via the Fixed Resource Requirement alternative (FRR) in which load-serving entities self-supply their generation through owned or contracted resources. All AEP East Companies other than AEP Ohio utilize the FRR alternative.

In January 2026, the White House, all thirteen state governors from across the PJM footprint, and senior federal energy officials jointly released a Statement of Principles. This Statement of Principles is designed to increase capacity available in the PJM market for large load customers and to ensure the costs of those resources are paid for by the large load customers to protect existing customer affordability. The Statement of Principles directs PJM to hold a one-time Reliability Backstop Auction, accelerate capacity market reforms in response to unprecedented data center load growth, and align costs associated with new capacity coming into the market with the large load customers necessitating the resources. Subsequently, in a proceeding pending since 2025, the Board of Directors of PJM issued a decision letter initiating changes to PJM's capacity market and interconnection processes.

As direct participants in the PJM capacity market, these reforms have the potential to materially impact AEP's competitive retail operations and could materially alter OPCo's cost allocations to retail customers.

AEP will continue to engage constructively with governors, regulators, PJM, and state and federal policymakers to support reforms that strengthen grid reliability, enable economic growth, and provide transparent, durable investment signals for utilities and investors. Management will continue to monitor activity within PJM and cannot predict the ultimate impact of these early-stage capacity market reform efforts or whether the FRR alternative will be impacted. If changes to PJM auction rules affect AEP's existing or prospective customer contracts or generation development strategy, it could affect future results of operations.

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

During 2025, PSO acquired four power generation facilities to strengthen its portfolio and enhance reliability. Additionally, in the fourth quarter of 2025, APCo acquired the Top Hat Wind Facility and SWEPCo acquired the Wagon Wheel Wind Facility. These transactions reflect the company's focus on securing necessary generation to meet future customer demand. See "Acquisitions" section of Note 7 for additional information. The table below summarizes these acquisitions:

Company	Plant Name	Fuel Type	Location	Acquisition Date	Net Maximum Capacity
					(in MWs)
PSO	Pixley	Solar	Barber County, KS	May 2025	189
PSO	Green Country	Natural Gas	Jenks, OK	June 2025	904
PSO	Flat Ridge IV	Wind	Kingman and Harper Counties, KS	June 2025	135
PSO	Flat Ridge V	Wind	Kingman and Harper Counties, KS	August 2025	153
APCo	Top Hat	Wind	Logan County, Illinois	November 2025	204
SWEPCo	Wagon Wheel	Wind	Multiple Counties, Oklahoma	December 2025	598
Total					2,183

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. Regulatory proceedings in all three jurisdictions are underway. If approved, the projects will help SWEPCo address increasing SPP capacity requirements. SWEPCo estimates the combined capital cost of these projects is approximately $723 million and the projects would be placed in service between December 2027 and May 2028.

In February 2025, I&M filed an application with the IURC to acquire the Oregon Generation Plant (Oregon), an 870 MW combined-cycle power generation facility located near Toledo, Ohio. In April 2025, I&M submitted a FERC 203 application for the acquisition and received approval in October 2025. In August 2025, I&M reached a unanimous settlement in the filing submitted to the IURC with intervening parties approving the acquisition of the Oregon facility and cost recovery. In November 2025, the IURC issued an order granting a CPCN to I&M for its acquisition of the Oregon facility. I&M expects to close on the transaction in the first quarter of 2026.

In January 2026, the IURC issued a separate order approving the settlement agreement in I&M's Indiana Expedited Generation Resource (EGR) Plan filing. This order approving the settlement agreement allows I&M to seek expedited IURC approval of future proposed PPAs, capacity purchase agreements (CPAs) and owned generation resources to serve I&M's increasing customer load and to implement deferral accounting for the generation resources that are approved by the IURC through the EGR Plan process.

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. If approved, the combustion turbines would be projected to be online by the end of 2028.

Significant Approved Renewable Generation Filings

AEP received regulatory approvals from various state regulatory commissions to acquire approximately 1,285 MWs of owned renewable generation facilities, totaling approximately $3.6 billion. The Financial Condition section below includes the estimated cost of these facilities in the Budgeted Capital Expenditures. In addition, AEP received regulatory approvals for 1,067 MWs of renewable PPAs. The recently enacted OBBBA legislation is not expected to affect the eligibility of these generation facilities for federal tax incentives. The following table summarizes regulatory approvals received for active renewable projects that are not yet in service as of December 31, 2025:

Company	Generation Type	Expected Commercial Operation	Owned/PPA	Generating Capacity
				(in MWs)
APCo	Solar	2026-2027	PPA	113
APCo (a)	Wind	2026-2029	Owned	401
I&M	Solar	2026-2027	PPA	280
I&M	Wind	2026-2030	PPA	674
I&M	Solar	2028	Owned	469
PSO (b)	Wind	2026	Owned	265
PSO (b)	Solar	2027	Owned	150
Total Approved Renewable Projects				2,352

(a) APCo has one wind project under construction.
(b) 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)
PSO (a)	November 2023	All-source	2027/2028	1,500
PSO	January 2026	All-source	2029	4,000
I&M (b)	September 2024	Wind, solar, dispatchable resources, BESS and emerging technology resources	2029	4,000
SWEPCo (c)	January 2024	Wind, solar, BESS and natural gas resources	2027/2028	2,100
APCo	May 2025	Owned wind, solar, co-located or stand-alone BESS	2029	800
APCo	May 2025	Purchased power from wind, solar, hydro or geothermal	2029	300
Total Significant RFPs				12,700

(a) RFP was negotiated and filed for regulatory approval in September 2025.
(b) Five wind resources selected totaling 574 MWs from the 2024 RFP have already been submitted and approved by the IURC. I&M expects to file applications with the IURC for regulatory approval of additional resources from the 2024 RFP in 2026.
(c) Two self-build natural gas resources totaling 1,503 MWs were selected and filed for regulatory approval in December 2024.

Capacity Purchase Agreements

In addition to the generation projects discussed above, AEP enters into Capacity Purchase Agreements (CPA) to satisfy operating companies' capacity reserve margins to serve customers. The following table includes CPA amounts under contract as of December 31, 2025, by year, for the five-year period 2026-2030:

	I&M		PSO		SWEPCo	
	Natural Gas	**Wind**	**Natural Gas**	**Wind**	**Natural Gas**	**Wind**
Delivery Start Year			**(in MWs)**			
2026	614	73	460	86	150	75
2027	769	—	410	86	300	100
2028	995	—	410	—	450	—
2029	995	—	410	—	450	—
2030	995	—	410	—	150	—

RECENT REGULATORY DEVELOPMENTS AND OTHER TRANSACTIONS

Regulatory Matters - Utility Rates and Rate Proceedings

The Registrants are involved in rate cases and other proceedings with their regulatory commissions in order to establish fair and appropriate electric service rates to recover their costs and earn a fair return on their investments. Depending on the outcomes, these rate cases and proceedings can have a material impact on results of operations, cash flows and possibly financial condition. AEP is currently involved in the following key proceedings.

The following tables show the Registrants' completed and pending base rate case proceedings in 2025. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

Company	Jurisdiction	Annual Base Revenue Increase (in millions)	Approved ROE	New Rates Effective	
APCo/WPCo	West Virginia	$ 76	9.25%	August 2025	(a)
SWEPCo	Arkansas	85	9.65%	February 2026	

(a) The WVPSC approved recovery of the base rate increase through current ENEC rates. The WVPSC issued an interim order approving securitization of APCo and WPCo under-recovery balances, with activity subsequent to 2024 subject to a final prudence review prior to securitization. See the "2024 West Virginia Base Rate Case" and "2025 West Virginia Securitization Filing" sections of Note 4 for additional information.

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Annual Base Revenue Increase Request (in millions)	Requested ROE
OPCo	Ohio	May 2025	$ 97	10.9%
KPCo	Kentucky	August 2025	96	10.0%
SWEPCo	Texas	October 2025	95	10.75%
PSO	Oklahoma	January 2026	299	10.5%

Other Significant Regulatory Matters

2025 West Virginia Securitization Filing

In March 2025, APCo and WPCo (the Companies) requested to finance, through the issuance of securitization bonds, approximately $2.4 billion of West Virginia jurisdictional undepreciated property balances and regulatory assets. In the third quarter of 2025, the Companies submitted post-hearing exhibits with a revised securitization request of approximately $2.5 billion, including: (a) $413 million of the Companies' combined unrecovered ENEC balances, (b) $1.7 billion of undepreciated West Virginia jurisdictional plant balances as of December 31, 2022 for the Amos, Mitchell and Mountaineer Plants, (c) $237 million of environmental costs previously approved for recovery through a separate West Virginia surcharge and (d) $158 million of West Virginia jurisdictional deferred major storm operation and maintenance costs. See "2025 West Virginia Securitization Filing" section of Note 4 for additional information.

In August 2025, the WVPSC issued an interim order stating that it will approve the Companies' future securitization of the generation plant assets, ENEC under-recovery balances, environmental costs and deferred storm operation and maintenance costs. All amounts above are subject to further review in a future final securitization financing order that the Companies expect will be issued by the WVPSC in 2026. Upon receipt of the final financing order, the Companies expect to proceed with the securitization bonds issuance process and to complete the securitization in the first half of 2026, subject to market conditions.

2025 Virginia Securitization Legislation and Securitization Filing

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

In July 2025, APCo filed a request with the Virginia SCC to finance, through the issuance of proposed 20-year securitization bonds, approximately $1.4 billion of Virginia jurisdictional undepreciated property balances and a major storm operation and maintenance regulatory asset deferral balance. This proposed securitization included: (a) $1.2 billion of undepreciated Virginia jurisdictional plant balances as of December 31, 2023 for the Amos and Mountaineer Plants and (b) $141 million of Virginia jurisdictional major storm other operation and maintenance expenses deferred during the 2024-2025 biennial period. In September 2025, Virginia SCC staff submitted testimony concluding that all costs proposed by APCo for securitization are eligible for securitization in accordance with Virginia law. While also concluding that APCo's proposed securitization of the Amos and Mountaineer Plants over 20 years offers benefits to customers through rate relief, Virginia SCC staff took no position on APCo's proposed securitization of major storm other operation and maintenance expenses due to the apparent lack of significant benefit or cost savings for customers. In October 2025, the Hearing Examiner recommended the Virginia SCC approve the requested $1.4 billion for securitization. In November 2025, the Virginia SCC issued a financing order approving securitization of the requested $1.4 billion of Virginia jurisdictional costs. In accordance with Virginia statutory requirements and the financing order, the issuance of the securitization bonds is subject to final review by the Virginia SCC after bond pricing. APCo expects to proceed with the securitization bond issuance process and to complete the securitization process in the first half 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.

NOLCs in Transmission Formula Rates - June 2025 FERC Order

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

Company	Increase (Decrease) in Pretax Income (a)	Decrease in Income Tax Expense (b)	Increase in Noncontrolling Interest (c)	Increase in Net Income
		(in millions)		
APCo	$ 8	$ 21	$ —	$ 29
I&M	17	28	—	45
PSO	(13)	16	—	3
SWEPCo	17	39	—	56
AEPTCo	214	203	(55)	362
Other (d)	(2)	6	—	4
AEP Total	$ 241	$ 313	$ (55)	$ 499

(a) Primarily represents the reversal of revenue refund provisions for years 2021-2025, partially offset by an increase in affiliated transmission expenses.
(b) Primarily relates to a $384 million remeasurement of Excess ADIT regulatory liabilities, partially offset by $71 million of tax expense on favorable pretax income.
(c) The noncontrolling interest relates to IMTCo and OHTCo. See "Noncontrolling Interest in Midwest Transmission Holdings" section of Note 7 for additional information.
(d) Includes KGPCo, KPCo, OPCo and WPCo.

NOLCs in Retail Jurisdictions - IRS PLRs

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

Company	Increase in Pretax Income from the Recognition of Regulatory Assets	Reduction in Income Tax Expense (a)	Increase in Net Income
		(in millions)	
I&M	$ 20	$ 50	$ 70
PSO	12	45	57
SWEPCo	35	101	136
AEP Total	$ 67	$ 196	$ 263

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

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

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

(a) AEP Texas and OPCo do not have NOLCs on a stand-alone basis.
(b) Pending receipt of jurisdiction specific IRS PLR.

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 December 31, 2025, AEP has NOLC regulatory assets of $108 million on its balance sheet.

Noncontrolling Interest in Midwest Transmission Holdings (Applies to AEP and AEPTCo)

In June 2025, a nonaffiliated entity acquired 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. AEP received cash proceeds of approximately $2.78 billion, net of transaction costs, which were used to help finance AEP's capital plan. See "Noncontrolling Interest in Midwest Transmission Holdings" section of Note 7 for additional information.

Kentucky Securitization Case

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

New Legislation

Ohio Legislation

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

In 2025, as a result of this legislation, OPCo recorded a $24 million reduction to its OVEC-related purchased power regulatory asset for deferred net costs that are no longer probable of future recovery. Management is unable to predict the future impact to net income, cash flows and financial condition arising from the future changes in OPCo's rate setting mechanisms and the elimination of OPCo's ability to recover from, or refund to, customers the difference between purchased power expenses from OVEC and the market revenues OPCo receives from that purchased power. See "OVEC" section of Note 18 for additional information.

Texas Legislation

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

The UTM permits a qualifying electric utility to defer all or a portion of costs associated with its eligible transmission and distribution capital investments, including depreciation expense and carrying costs, as a regulatory asset. The tracking mechanism is available through 2035 and is an alternative to the existing capital tracking mechanisms in Texas. As a result of the new legislation, AEP Texas deferred approximately $56 million of eligible costs through December 2025 as a regulatory asset.

2025 UTM Filing

In October 2025, AEP Texas submitted its first filing with the PUCT seeking recovery of eligible costs through the UTM established by HB 5247. This filing combined three recovery mechanisms (Interim Transmission Cost of Service and Distribution Cost Recovery Factor capital trackers and the Transmission Cost Recovery Factor) into a single filing. The capital tracker incremental revenue requirement, inclusive of the items outlined in the January 2026 brief, sought in this filing is $100 million, including a request to recover, over a 12-month period, $38 million of eligible costs related to UTM deferrals and $2 million of eligible costs related to the System Resiliency Plan deferrals, both inclusive of equity carrying charges through the July 2025 test year period end. In November 2025, an intervenor proposed a $31 million reduction to the UTM deferral balance. The filing is currently undergoing a paper hearing and in January 2026 the parties filed briefs reiterating their position. A resolution is expected in the first half of 2026. Investments included in the UTM and the existing capital tracker filings remain subject to prudency review in the utility's next base rate review before the PUCT. If any of these deferred costs are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

Oklahoma Legislation

Effective August 28, 2025, in accordance with Oklahoma Senate Bill 998 (SB 998), a public utility may defer up to 90% of all depreciation expense and return associated with qualifying electric plant to a regulatory asset, provided the utility has notified the OCC of its election to do so. SB 998 excludes deferral of costs related to transmission plant and new electric generating units. Deferred costs will be recovered through base rates over a 20-year period and earn a return until recovered. SB 998 also allows for expedited recovery of new gas plant investments. Through December 31, 2025, PSO deferred $9 million of qualifying costs to a regulatory asset to be recovered through future base rates.

Federal Tax Legislation

On July 4, 2025, President Trump signed H.R. 1 into law, commonly known as the One Big Beautiful Bill Act (OBBBA). 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 or influence 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 prospective and has no material impact on the current period financial statements.

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. This guidance is not expected to have a material impact on the Registrants.

On September 30, 2025, the Department of Treasury and the IRS issued interim guidance regarding the application of CAMT, Notice 2025-49. This guidance is not expected to have a material impact on the Registrants.

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.

Midcontinent Grid Solutions Investment (Applies to AEP and Transource Energy)

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 are estimated to cost approximately $1.2 billion and Transource Energy's share of this investment is estimated to be $600 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 May 2025, Midcontinent Grid Solutions, LLC's subsidiary, Midcontinent Grid Solutions Iowa, LLC (MGS Iowa) submitted to FERC a request for acceptance of formula rates, consisting of a formula rate template and implementation protocols, effective July 2025.

In September 2025, the FERC issued an order accepting the formula rate, granting MGS Iowa's 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. 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 Midcontinent Grid Solutions Iowa, LLC (MGS Iowa), MGS Wisconsin is authorized to replicate MGS Iowa's FERC-approved formula rate without further FERC approval.

Valley Link Investment (Applies to AEP and Transource Energy)

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

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

Fuel Cell Agreement

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

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.

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

In January 2026, under the existing option to acquire additional fuel cells, an unregulated AEP subsidiary entered into an agreement to acquire solid oxide fuel cells for approximately $2.65 billion to develop a fuel cell generation facility near Cheyenne, Wyoming. The subsidiary also entered into a 20-year offtake agreement with an investment-grade customer for 100% of the facility’s output. The offtake arrangement is subject to certain conditions that AEP expects to be satisfied by the second quarter of 2026. If these conditions are not met, AEP will receive financial compensation for all capital and costs incurred.

Forward Sale of Equity

In March 2025, AEP entered into separate forward sale agreements with non-affiliate forward purchasers relating to 22,549,020 shares of AEP’s common stock at an initial price of $102.00 per share, exclusive of an underwriting discount equal to $2.244 per share. Except in certain specified circumstances that would require physical share settlement, AEP may elect to settle the forward sale transaction by means of physical, cash or net share settlement. The timing of the settlement of the forward sale agreements is also at AEP’s discretion, and management currently expects settlement to occur on or prior to December 31, 2026. To the extent the forward sale agreements are physically settled, AEP will issue common stock to the forward purchasers and receive cash proceeds based on the applicable forward sale price on the settlement date as defined in the forward sale agreements. For the year ended 2025, AEP issued 5,022,229 shares of common stock and received net cash proceeds of $500 million. As of December 31, 2025, AEP expects approximately $1.7 billion of net cash proceeds from the remaining physical settlement of the forward sale agreements and management anticipates using any future proceeds for general corporate purposes, capital investments, acquisitions or repayment of debt. The forward sale transactions will be classified as equity transactions because they are indexed to AEP’s common stock and physical settlement is within AEP’s control.

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 6 – 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 EPA 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 6 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 December 31, 2025, AEP owned generating capacity of approximately 25,400 MWs, of which approximately 10,700 MWs were coal-fired. In April 2024, the Federal EPA announced four major new rules directed at fossil-fuel electric generation facilities. Management continues to evaluate the impacts of these rules on the plans for the future of AEP's generating fleet, in particular, the economic feasibility of making the requisite environmental investments in AEP's fossil generation fleet. AEP continues to refine the cost estimates of complying with these rules to identify the best alternative for promoting compliance with all of the rules while meeting AEP's obligations to provide reliable and affordable electricity.

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

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. Revisions tend to increase the stringency of the standards, which in turn may require AEP to make investments in pollution control equipment at existing generating units, or, since most units are already well controlled, to make changes in how units are dispatched and operated. In February 2024, the Federal EPA finalized a new more stringent annual primary $PM_{2.5}$ standard.

Areas with air quality that does not meet the new standard will be designated by the Federal EPA as "nonattainment," which will trigger an obligation for states to revise their SIPs to include additional requirements, resulting in further emission reductions to meet the new standard. 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.

If the rule is not vacated, areas around some of AEP's generating facilities may be deemed nonattainment, which may require those facilities to install additional pollution controls or to implement operational constraints. Any nonattainment designations by the Federal EPA and the subsequent SIP revisions by affected states will take time to finalize and complete. 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. Management will continue to monitor the 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.

Cross-State Air Pollution Rule

CSAPR is a regional trading program that the Federal EPA began implementing in 2015 to address interstate transport of emissions that contribute significantly to nonattainment and interfere with maintenance of the 1997 ozone NAAQS and the 1997 and 2006 $PM_{2.5}$ NAAQS in downwind states. CSAPR relies on SO_2 and NO_X allowances and individual state budgets to compel further emission reductions from electric utility generating units. Interstate trading of allowances is allowed on a restricted basis. The Federal EPA has revised, or updated, the CSAPR trading programs several times since they were established.

In January 2021, the Federal EPA finalized a revised CSAPR, which substantially reduced the ozone season NO_X budgets for several states, including states where AEP operates, beginning in ozone season 2021. AEP met the requirements of the revised rule over the first few years of implementation, and is evaluating its compliance options for future years, when the budgets are further reduced.

In February 2023, the Federal EPA Administrator finalized the disapproval of interstate transport SIPs submitted by 19 states, including Texas, addressing the 2015 Ozone NAAQS. The Federal EPA disapproved interstate transport SIPs submitted by additional states soon thereafter. Disapproval of the SIPs provided the Federal EPA with authority to impose a FIP for those states, replacing the SIPs that were disapproved. In August 2023, a FIP (the Good Neighbor Plan) went into effect that further revised the ozone season NO_X budgets under the existing CSAPR program in states to which the FIP applies. The FIP has since been administratively stayed pending the Supreme Court lifting its order staying enforcement of the Good Neighbor Plan, other courts lifting any judicial orders staying the SIP disapproval action as to the state, 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 has stayed the litigation pending rulemaking by the Federal EPA. In June 2025, the Federal EPA proposed to determine that GHG emissions from fossil-fueled power plants do not significantly contribute to air pollution that may endanger public health or the environment. This determination would eliminate all GHG standards for existing and new fossil-fuel plants. As an alternative, the Federal EPA proposed to eliminate GHG standards for existing coal and gas units and to keep only certain emission limits applicable to new sources. These proposals have not been finalized. In July 2025, the Federal EPA proposed to repeal the 2009 Endangerment Finding, which determined that greenhouse gas emissions endanger public health and welfare. The 2009 Endangerment Finding is the basis of the Federal EPA's authority to regulate greenhouse gas emissions under the Clean Air Act and was used to first regulate motor vehicle emissions. Management is evaluating the Federal EPA's proposed repeal of the 2009 Endangerment Finding and its impact on the Federal EPA's authority to regulate greenhouse gas emissions from electric generators. Management cannot predict the outcome of the current litigation or the Federal EPA's proposed actions related to the rule or the Endangerment Finding and any subsequent litigation that may result. Excessive costs to comply with environmental regulations have led to the announcement of early plant closures across the country. 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. A recent evaluation demonstrated that changing external conditions and business growth, including unprecedented load growth, evolving market and policy dynamics, and jurisdictional preferences will impact AEP's corporate-wide pathway to reduce Scope 1 GHG emissions by 80% by 2030 through collective state IRPs. Accordingly, AEP continues to focus on supporting state-based clean energy mandates and decarbonization targets, including meeting the Virginia Clean Economy Act and Michigan Public Act 235 mandates that are on track for achievement. AEP remains committed to seeking advanced low-carbon generation solutions where supported. As an example, APCo and I&M are seeking early site permits to bring small modular reactors to Virginia and Indiana. In light of this shift, AEP will continue to assess aspirations to achieve net-zero Scope 1 and 2 emissions by 2045. AEP's performance will ultimately be driven by the needs and desires of the states 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 June 2025, the Federal EPA proposed to repeal the 2024 MATS rule and revert to the 2012 MATS rule emission standards. Management does not anticipate any significant challenges complying with the 2024 MATS rule, should the proposed repeal not be finalized.

CCR Rule

The Federal EPA's CCR Rule regulates the disposal and beneficial re-use of CCR, including fly ash and bottom ash created from coal-fired generating units and FGD gypsum generated at some coal-fired plants. As originally promulgated 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 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 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. Additional revisions to the CCR Rule are expected in 2026.

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 6 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 have committed by December 31, 2025 to retire by 2034. Management is evaluating the compliance alternatives in the rule, taking into consideration the requirements of the other new rules and their combined impacts to operations. Several appeals have been filed with various federal courts challenging the 2024 ELG rule. SWEPCo also challenged the rule by filing a joint appeal 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 and the Federal EPA has subsequently announced plans to reconsider the standards and deadlines established by the 2024 ELG rule. Management cannot predict the outcome of the litigation.

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. Management cannot predict the outcome of 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 December 31, 2025:

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	$ 73	$ 221	2026	(c)	$ 15
SWEPCo	Pirkey Plant	—	94 (d)	2023	(e)	—
SWEPCo	Welsh Plant, Units 1 and 3	269	220	2028 (f)	(g)	47

(a) Net book value including CWIP excluding cost of removal and materials and supplies.
(b) These amounts represent the amount of annual depreciation that has been collected from customers over the prior 12-month period.
(c) Northeastern Plant, Unit 3 is currently being recovered through 2040. In April 2025, PSO and ODEQ finalized a second amended regional haze agreement that would allow continued operation of the Northeastern Plant, Unit 3, on natural gas, through May 31, 2041. This agreement is contingent upon approval by the Federal EPA in the form of a revised SIP. ODEQ is in the process of preparing a SIP submission for the Federal EPA's review and approval.
(d) Represents Texas and FERC 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 Units" section of Note 5 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.
(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 9 - Business Segments for additional information on AEP's segments.

The following discussion of AEP's results of operations by operating segment provides a comparison of earnings (loss) attributable to AEP common shareholders for the year ended December 31, 2025 as compared to the year ended December 31, 2024. 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 years ended December 31, 2025 and 2024, see the discussions of Results of Operations by Registrant Subsidiary.

A detailed discussion of AEP's 2024 results of operations by operating segment can be found in Management's Discussion and Analysis of Financial Condition and Results of Operation section included in the 2024 Annual Report on Form 10-K filed with the SEC on February 13, 2025.

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

	Years Ended December 31,		
	2025	2024	2023
		(in millions)	
Vertically Integrated Utilities	$ 1,605	$ 1,453	$ 1,090
Transmission and Distribution Utilities	816	726	699
AEP Transmission Holdco	1,161	790	703
Generation & Marketing	287	289	(26)
Corporate and Other	(289)	(291)	(258)
Earnings Attributable to AEP Common Shareholders	$ 3,580	$ 2,967	$ 2,208

See Note 9 - Business Segments for additional information on Earnings (Loss) Attributable to AEP Common Shareholders by segment.

Heating Degree Days and Cooling Degree Days

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

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

VERTICALLY INTEGRATED UTILITIES

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Years Ended December 31,		
	2025	2024	2023
	(in millions of KWhs)		
Retail:			
Residential	31,844	31,025	30,290
Commercial	26,295	24,647	23,481
Industrial	33,571	34,013	34,148
Miscellaneous	2,257	2,271	2,229
Total Retail	93,967	91,956	90,148
Wholesale (a)	16,039	14,523	13,401
Total KWhs	110,006	106,479	103,549

(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

	Years Ended December 31,		
	2025	2024	2023
	(in degree days)		
Eastern Region			
Actual – Heating	2,741	2,092	1,992
Normal – Heating	2,646	2,704	2,719
Actual – Cooling	1,120	1,366	1,003
Normal – Cooling	1,110	1,114	1,119
Western Region			
Actual – Heating	1,354	1,052	1,068
Normal – Heating	1,436	1,450	1,464
Actual – Cooling	2,506	2,738	2,590
Normal – Cooling	2,307	2,289	2,277

Reconciliation of Year Ended December 31, 2024 to Year Ended December 31, 2025
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Year Ended December 31, 2024	$ 1,453
Changes in Revenues:	
Retail Revenues	956
Off-system Sales	145
Transmission Revenues	113
Other Revenues	8
Total Change in Revenues	1,222
Changes in Expenses and Other:	
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	(260)
Other Operation and Maintenance	(356)
Asset Impairments and Other Related Charges	(21)
Depreciation and Amortization	(105)
Taxes Other Than Income Taxes	3
Other Income	(1)
Allowance for Equity Funds Used During Construction	22
Non-Service Cost Components of Net Periodic Pension Cost	1
Interest Expense	(132)
Total Change in Expenses and Other	(849)
Income Tax Benefit	(222)
Net Income Attributable to Noncontrolling Interests	1
Year Ended December 31, 2025	$ 1,605

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

- **Retail Revenues** increased $956 million primarily due to the following:
  - A $601 million increase in base rate and rider revenues.
  - A $148 million increase at SWEPCo due to a revenue refund provision recorded in 2024 associated with the Turk Plant and SWEPCo's 2012 Texas Base Rate Case.
  - A $133 million increase in weather-normalized revenues primarily in the residential and commercial classes, partially offset by a decrease in the industrial class.
  - A $109 million increase in fuel revenues.
  - A $50 million increase in weather-related usage primarily in the residential class driven by a 30% increase in heating degree days.

  These increases were partially offset by:
  - An $86 million decrease due to regulatory provisions for refund at I&M.
- **Off-system Sales** increased $145 million primarily due to economic hedging activity, Rockport Plant, Unit 2 merchant sales at I&M and capacity revenues recognized from the RPM auction for the 2025-2026 planning year at APCo.
- **Transmission Revenues** increased $113 million primarily due to the following:
  - A $65 million increase due to continued transmission investment.
  - A $56 million increase due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- **Other Revenues** increased $8 million primarily due to gains from the sale of renewable energy credits.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $260 million primarily due to increases at I&M and PSO, partially offset by decreases at APCo and SWEPCo.
- **Other Operation and Maintenance** expenses increased $356 million primarily due to the following:
  - A $114 million increase in distribution expenses primarily due to vegetation management costs.
  - An $88 million increase in PJM and SPP transmission expenses.

- A $60 million increase in generation expenses.
- A $60 million increase in employee-related expenses.
- A $53 million increase due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- A $29 million increase in customer operations and services primarily due to recoverable energy assistance program expenses for qualified Virginia customers at APCo.

These increases were partially offset by:

- A $76 million decrease due to the voluntary severance program that occurred in the second quarter of 2024.
- A $14 million decrease due to a disallowance recorded on the remaining net book value of the Dolet Hills Power Station as a result of an LPSC approved settlement agreement in April 2024.

- **Asset Impairments and Other Related Charges** increased $21 million primarily due to the following:
  - A $34 million increase due to an impairment of in-process internal use software development costs.

  This increase was partially offset by:
  - A $13 million decrease due to the Federal EPA's revised CCR rules finalized in 2024.
- **Depreciation and Amortization** expenses increased $105 million primarily due to the following:
  - A $117 million increase primarily due to a higher depreciable base at APCo, I&M, PSO and SWEPCo.
  - A $20 million increase at I&M due to a prior year deferral combined with current year amortization of Excess ADIT as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail ratemaking.
  - A $20 million increase at SWEPCo due to the amortization of the Storm Recovery Funding securitized assets.

  These increases were partially offset by:
  - A $61 million decrease due to the under-recovery of regulatory assets related to renewables at PSO and SWEPCo.
- **Allowance for Equity Funds Used During Construction** increased $22 million primarily due to increased AFUDC base and rates.
- **Interest Expense** increased $132 million primarily due to higher long-term debt balances at APCo, PSO and SWEPCo and a prior year deferral of expenses as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail ratemaking at I&M, PSO and SWEPCo.
- **Income Tax Benefit** decreased $222 million primarily due to the following:
  - A $212 million decrease due to a reduction in Excess ADIT regulatory liabilities at I&M, PSO and SWEPCo as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail ratemaking recorded in 2024.
  - A $78 million decrease due to an increase in pretax book income.
  - A $32 million decrease due to the reversal of a regulatory liability related to the merchant portion of Turk Plant Excess ADIT as a result of the APSC's denial of SWEPCo's request to allow the merchant portion of the Turk Plant to serve Arkansas customers recorded in 2024.

  These decreases were partially offset by:
  - A $114 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.

TRANSMISSION AND DISTRIBUTION UTILITIES

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Years Ended December 31,		
	2025	2024	2023
	(in millions of KWhs)		
Retail:			
Residential	27,437	26,782	26,099
Commercial	46,187	36,147	30,419
Industrial	28,020	27,368	26,571
Miscellaneous	728	742	745
Total Retail (a)	102,372	91,039	83,834
Wholesale (b)	2,250	2,014	1,922
Total KWhs	104,622	93,053	85,756

(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

	Years Ended December 31,		
	2025	2024	2023
	(in degree days)		
Eastern Region			
Actual – Heating	3,273	2,446	2,380
Normal – Heating	3,057	3,140	3,185
Actual – Cooling	1,098	1,300	842
Normal – Cooling	1,056	1,031	1,026
Western Region			
Actual – Heating	348	196	197
Normal – Heating	323	316	318
Actual – Cooling	2,956	3,249	3,208
Normal – Cooling	2,641	2,770	2,737

Reconciliation of Year Ended December 31, 2024 to Year Ended December 31, 2025
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Year Ended December 31, 2024	$	726
Changes in Revenues:		
Retail Revenues		195
Off-system Sales		56
Transmission Revenues		72
Other Revenues		(84)
Total Change in Revenues		239
Changes in Expenses and Other:		
Purchased Electricity for Resale		(67)
Purchased Electricity from AEP Affiliates		33
Other Operation and Maintenance		(152)
Asset Impairments and Other Related Charges		22
Depreciation and Amortization		59
Taxes Other Than Income Taxes		(20)
Other Income		(8)
Allowance for Equity Funds Used During Construction		8
Non-Service Cost Components of Net Periodic Benefit Cost		9
Interest Expense		(18)
Total Change in Expenses and Other		(134)
Income Tax Expense		(18)
Equity Earnings of Unconsolidated Subsidiaries		3
Year Ended December 31, 2025	$	816

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

- **Retail Revenues** increased $195 million primarily due to the following:
  - A $171 million increase in base case and rider revenues.
  - A $26 million increase in weather-related usage driven by a 34% increase in heating degree days in Ohio.

  These increases were partially offset by:
  - A $14 million decrease in weather-normalized revenues primarily in the residential class in Ohio.
- **Off-system Sales** increased $56 million primarily due to increased sales of OVEC purchased power driven by higher market prices and volume.
- **Transmission Revenues** increased $72 million primarily due to the following:
  - A $120 million increase primarily due to continued transmission investments.

  This increase was partially offset by:
  - A $48 million decrease due to lower peak loads included in 2025 billing rates in Texas.
- **Other Revenues** decreased $84 million primarily due to the following:
  - A $74 million decrease in securitization revenues resulting from the maturity of Transition Funding III LLC securitization bonds in December 2024.
  - An $18 million decrease due to lower third-party Legacy Generation Resource Rider revenue as a result of approved legislation in Ohio in May 2025 which ended the retail recovery of OVEC purchased power costs.

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

- **Purchased Electricity for Resale** expenses increased $67 million primarily due to the following:
  - A $35 million increase in recoverable auction purchases from nonaffiliates to serve SSO customers in Ohio.
  - A $24 million increase due to a reduction in regulatory assets for OVEC-related purchased power costs that are no longer probable of future recovery due to approved legislation in Ohio in May 2025.
  - A $13 million increase in OVEC-related purchased power expenses.

- **Purchased Electricity from AEP Affiliates** expenses decreased $33 million primarily due to decreased recoverable auction purchases from AEP Energy Partners to serve SSO customers in Ohio.
- **Other Operation and Maintenance** expenses increased $152 million primarily due to the following:
  - A $105 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses in Ohio.
  - A $54 million increase in recoverable Transmission Cost Recovery Factor expenses in Texas.
  - A $22 million increase in employee-related expenses.
  - A $19 million increase in transmission and distribution expenses in Texas.

  These increases were partially offset by:
  - A $35 million decrease due to the voluntary severance program that occurred in the second quarter of 2024.
  - A $29 million decrease related to recoverable energy assistance program expenses for qualified Ohio customers.
- **Asset Impairments and Other Related Charges** decreased $22 million due to the following:
  - A $53 million decrease due to the Federal EPA's revised CCR rules finalized in 2024.

  This decrease was partially offset by:
  - A $31 million increase due to an impairment of in-process internal use software development costs in 2025.
- **Depreciation and Amortization** expenses decreased $59 million primarily due to the following:
  - A $71 million decrease in the amortization of securitized transition assets due to the maturity of Transition Funding III LLC securitization bonds.
  - A $23 million decrease due to the deferral of eligible costs related to the UTM.

  These decreases were partially offset by:
  - A $37 million increase due to a higher depreciable base in Texas.
- **Taxes Other Than Income Taxes** increased $20 million primarily due to higher property taxes.
- **Other Income** decreased $8 million primarily due to lower interest income as a result of lower advances to affiliates.
- **Allowance for Equity Funds Used During Construction** increased $8 million due to a higher AFUDC base in Texas.
- **Non-Service Cost Components of Net Period Benefit Cost** decreased $9 million primarily due to an increase in loss amortization for the plans and a plan remeasurement triggered by settlements related to the voluntary severance program in 2024, partially offset by lower interest costs due to lower discount rates.
- **Interest Expense** increased $18 million primarily due to the following:
  - A $46 million increase due to higher long-term debt balances and interest rates.

  This increase was partially offset by:
  - A $28 million decrease due to the deferral of eligible costs related to the UTM.
- **Income Tax Expense** increased $18 million primarily due to an increase in pretax book income.

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	December 31, 2025	December 31, 2024
	(in millions)	
Plant in Service	$ 17,662	$ 15,835
Construction Work in Progress	2,167	2,206
Accumulated Depreciation and Amortization	1,968	1,626
Total Transmission Property, Net	$ 17,861	$ 16,415

Reconciliation of Year Ended December 31, 2024 to Year Ended December 31, 2025
Earnings Attributable to AEP Members from AEP Transmission Holdco
(in millions)

Year Ended December 31, 2024	$ 790
Changes in Transmission Revenues:	
Transmission Revenues	426
Total Change in Transmission Revenues	426
Changes in Expenses and Other:	
Other Operation and Maintenance	(31)
Depreciation and Amortization	(47)
Taxes Other Than Income Taxes	(13)
Interest and Investment Income	(5)
Allowance for Equity Funds Used During Construction	4
Non-Service Cost Components of Net Periodic Pension Cost	4
Interest Expense	(19)
Total Change in Expenses and Other	(107)
Income Tax Expense	173
Equity Earnings of Unconsolidated Subsidiaries	(12)
Net Income Attributable to Noncontrolling Interests	(109)
Year Ended December 31, 2025	$ 1,161

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

- **Transmission Revenues** increased $426 million primarily due to the following:
  - A $214 million increase due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
  - A $212 million increase due to continued transmission investment.

Expenses and Other, Income Tax Expense, Equity Earnings of Unconsolidated Subsidiaries and Net Income Attributable to Noncontrolling Interests changed between years as follows:

- **Other Operation and Maintenance** expenses increased $31 million primarily due to an increase in employee-related expenses, vegetation management expenses and other various miscellaneous expenses, partially offset by a decrease due to the voluntary severance program that occurred in the second quarter of 2024.
- **Depreciation and Amortization** expenses increased $47 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $13 million primarily due to higher property taxes driven by increased transmission investment.
- **Interest and Investment Income** decreased $5 million primarily due to lower advances to affiliates.
- **Interest Expense** increased $19 million primarily due to higher long-term debt balances and interest rates.

- **Income Tax Expense** decreased $173 million primarily due to the following:
  - A $254 million decrease due to a reduction in Excess ADIT as a result of the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

  This decrease was partially offset by:
  - A $64 million increase due to an increase in pretax book income.
  - A $15 million increase due to an increase in state taxes.
- **Equity Earnings of Unconsolidated Subsidiaries** decreased $12 million primarily due to lower pretax earnings by ETT and PATH-WV.
- **Net Income Attributable to Noncontrolling Interests** increased $109 million primarily due to the Midwest Transmission noncontrolling interest transaction that closed in June 2025.

GENERATION & MARKETING

Reconciliation of Year Ended December 31, 2024 to Year Ended December 31, 2025
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Year Ended December 31, 2024	$	289
Changes in Revenues:		
Merchant Generation		90
Renewable Generation		(24)
Retail, Trading and Marketing		651
Total Change in Revenues		717
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation		(783)
Other Operation and Maintenance		47
Asset Impairments and Other Related Charges		76
Depreciation and Amortization		5
Interest and Investment Income		(1)
Non-Service Cost Components of Net Periodic Benefit Cost		(2)
Interest Expense		9
Total Change in Expenses and Other		(649)
Income Tax Expense		(69)
Equity Earnings of Unconsolidated Subsidiaries		(1)
Year Ended December 31, 2025	$	287

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

- **Merchant Generation** increased $90 million primarily due to higher realized prices in 2025.
- **Renewable Generation** decreased $24 million primarily due to the sale of AEP Onsite Partners in September 2024.
- **Retail, Trading and Marketing** increased $651 million primarily due to higher market prices in 2025.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $783 million primarily due to an increase in energy costs in 2025.
- **Other Operation and Maintenance** expenses decreased $47 million primarily due to renewable contract termination proceeds in 2025 and the sale of AEP OnSite Partners in September 2024.
- **Asset Impairments and Other Related Charges** decreased $76 million due to the Federal EPA's revised CCR Rules finalized in 2024.
- **Depreciation and Amortization** expenses decreased $5 million primarily due to the sale of AEP Onsite Partners in September 2024.
- **Interest Expense** decreased $9 million primarily due to lower advances from affiliates.
- **Income Tax Expense** increased $69 million primarily due to the following:
  - A $54 million increase due to a decrease in amortization of deferred ITCs related to the sale of NMRD and AEP OnSite Partners in 2024.
  - A $14 million increase due to an increase in pretax book income.

CORPORATE AND OTHER

2025 Compared to 2024

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $291 million in 2024 to a loss of $289 million in 2025 primarily due to:

- A $21 million decrease in interest expense primarily due to lower short-term debt balances and interest rates.
- A $19 million loss contingency recorded in 2024 associated with the SEC investigation.
- An $18 million increase in equity earnings.
- An $11 million increase due to the recognition of deferred revenues for completed agreements.

These increases in earnings were partially offset by:

- A $31 million decrease in Income Tax Benefit primarily due to an increase in state taxes.
- A $30 million decrease in interest income primarily due to lower advances to affiliates.
- A $7 million decrease at EIS primarily due to increased insurance reserves.

AEP CONSOLIDATED INCOME TAXES

2025 Compared to 2024

- **Income Tax Expense** increased $168 million primarily due to the following:
  - A $212 million increase due to a reduction in Excess ADIT regulatory liabilities at I&M, PSO and SWEPCo as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail ratemaking recorded in 2024.
  - A $187 million increase due to an increase in pretax book income.
  - A $54 million increase due to a decrease in amortization of deferred ITCs primarily due to the sale of NMRD and Onsite Partners in 2024.
  - A $32 million increase due to a reduction in Excess ADIT regulatory liabilities as a result of the APSC's denial of SWEPCo's request to allow the merchant portion of the Turk Plant to serve Arkansas customers recorded in 2024.
  - A $29 million increase due to a decrease in amortization of Excess ADIT.
  - A $15 million increase due to an increase in state taxes.

  These increases were partially offset by:

  - A $368 million decrease due to a reduction in Excess ADIT as a result of the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

FINANCIAL CONDITION

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

SIGNIFICANT CASH REQUIREMENTS

AEP's contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in the footnotes. It is anticipated that these obligations will be satisfied through a combination of cash flows from operations, long-term debt issuances, short-term debt through AEP's Commercial Paper Program or bank term loans, the use of the ATM Program, the March 2025 forward sale of equity agreement or other equity issuances.

Capital Expenditures

Continued capital investments reflect AEP's dedication to enhance service and deliver safe, reliable power to customers. In October 2025, AEP announced a $72 billion capital plan for 2026-2030 driven by transmission and distribution infrastructure upgrades and new generation to support anticipated load growth. See "Budgeted Capital Expenditures" herein, for additional information.

Long-term Debt

Long-term debt maturities, including interest, represent a significant cash requirement for AEP and the Registrant Subsidiaries. See Note 15 - Financing Activities for additional information relating to the Registrant Subsidiaries' long-term debt outstanding as of December 31, 2025, the weighted-average interest rate applicable to each debt category and a schedule of debt maturities over the next five years.

Other Significant Cash Requirements

Operating and finance leases represent a significant component of funding requirements for AEP and the Registrant Subsidiaries. See Note 13 - Leases for additional information.

AEP subsidiaries have substantial commitments for fuel, energy and capacity contracts as part of the normal course of business. See Note 6 - Commitments, Guarantees and Contingencies for additional information.

As of December 31, 2025, AEP expected to make contributions to the pension plans totaling $83 million in 2026. Estimated contributions of $84 million in 2027 and $85 million in 2028 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the projected benefit obligation and fair value of assets available to pay pension benefits, the pension plans were 98% funded as of December 31, 2025. See "Estimated Future Benefit Payments and Contributions" section of Note 8 for additional information.

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 security reserves. There is no collateral held in relation to any guarantees in excess of the ownership percentages. In the event any letters of credit are drawn, there is no recourse to third-parties. See "Letters of Credit" section of Note 6 for additional information.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31, 2025		December 31, 2024	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 47,322	58.4 %	$ 42,643	59.1 %
Short-term Debt	1,508	1.9	2,524	3.5
Total Debt	48,830	60.3	45,167	62.6
AEP Common Equity	31,138	38.4	26,944	37.3
Noncontrolling Interests	1,080	1.3	42	0.1
Total Debt and Equity Capitalization	$ 81,048	100.0 %	$ 72,153	100.0 %

AEP's ratio of debt-to-total capital decreased from 62.6% to 60.3% as of December 31, 2024 and December 31, 2025, respectively, primarily due to an increase in earnings and the Midwest Transmission Holdings Noncontrolling Interest transaction, partially offset by an increase in long-term debt to support 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 December 31, 2025, AEP had $6 billion in 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 December 31, 2025, available liquidity was approximately $5.6 billion as illustrated in the table below:

	Amount (in millions)		Maturity (a)
Commercial Paper Backup:			
Revolving Credit Facility	$	5,000	March 2029
Revolving Credit Facility		1,000	March 2027
Cash and Cash Equivalents		197	
Total Liquidity Sources		6,197	
Less: AEP Commercial Paper Outstanding		605	
Net Available Liquidity	$	5,592	

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 2025 was $2.9 billion. The average amount of commercial paper outstanding during 2025 was $1.4 billion. The weighted-average yield for AEP's commercial paper during 2025 was 4.47%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. As of December 31, 2025, AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $450 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of December 31, 2025 was $377 million with maturities ranging from January 2026 to November 2026.

Financing Plan

As of December 31, 2025, AEP had $3.2 billion of long-term debt due within one year. This included $1.6 billion of Senior Unsecured Notes, $1.1 billion of Term Loans, $240 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that require the debt to be classified as current and $204 million of securitization bonds and DCC Fuel notes. Management plans to replace or refinance substantially all of the maturities due within one year on a long-term basis.

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 December 31, 2025, the affiliated utility subsidiaries were in compliance with all requirements under the agreement.

Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in AEP's credit agreements. Debt as defined in the revolving credit agreement excludes securitization bonds and debt of AEP Credit. As of December 31, 2025, this contractually-defined percentage was 54.7%. Non-performance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $100 million, would cause an event of default under these credit agreements. This condition also applies, at the more restrictive level of $50 million of debt outstanding, in a majority of AEP's non-exchange-traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange-traded commodity contracts would not cause an event of default under its credit agreements.

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

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

March 2025 Forward Sale of Equity

See “Forward Sale of Equity” section of Note 15 for additional information regarding AEP’s forward sale of 22,549,020 shares of common stock in March 2025.

ATM Program

AEP participates in an ATM offering program that allows AEP to issue, from time to time, shares of its common stock, including shares of common stock that may be sold pursuant to an equity forward sales agreement. As of December 31, 2025, approximately $3.5 billion of equity is available for issuance under the ATM offering program. See “ATM Program” section of Note 15 - Financing Activities for additional information.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.95 per share in January 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 15 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.

	Years Ended December 31,		
	2025	2024	2023
		(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 246	$ 379	$ 557
Net Cash Flows from Operating Activities	6,944	6,804	5,012
Net Cash Flows Used for Investing Activities	(11,939)	(7,596)	(6,267)
Net Cash Flows from Financing Activities	5,017	659	1,077
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	22	(133)	(178)
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 268	$ 246	$ 379

Operating Activities

	Years Ended December 31,		
	2025	2024	2023
		(in millions)	
Net Income	$ 3,696	$ 2,976	$ 2,213
Non-Cash Adjustments to Net Income (a)	3,621	3,383	3,376
Mark-to-Market of Risk Management Contracts	(116)	(81)	9
Pension Contributions to Qualified Plan Trust	(95)	—	—
Property Taxes	(42)	(45)	(41)
Deferred Fuel Over/Under Recovery, Net	133	277	893
Change in Other Noncurrent Assets (b)	(863)	(522)	(762)
Change in Other Noncurrent Liabilities	269	306	29
Change in Certain Components of Working Capital	341	510	(705)
Net Cash Flows from Operating Activities	$ 6,944	$ 6,804	$ 5,012

(a) Includes Depreciation and Amortization, Deferred Income Taxes, Loss on the Sale of the Competitive Contracted Renewables Portfolio, Asset Impairments and Other Related Charges, Allowance for Equity Funds Used During Construction and Amortization of Nuclear Fuel.
(b) Includes Change in Regulatory Assets.

2025 Compared to 2024

Net Cash Flows from Operating Activities increased by $140 million primarily due to the following:

- A $958 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.

This increase in cash was partially offset by:

- A $341 million decrease in cash from Change in Other Noncurrent Assets primarily due to timing differences in collections from customers under rate rider mechanisms, including storm restoration expenses incurred in several jurisdictions. See Note 4 - Rate Matters and Note 5 - Effects of Regulation for additional information.
- A $169 million decrease in cash from the Change in Certain Components of Working Capital primarily due to an increase in fuel, material and supplies driven by higher coal inventory on hand, the timing of accounts receivable collections and changes in income tax payments and tax credits. These decreases were partially offset by the timing of accounts payable, employee-related benefits, proceeds received from the sale of transferable tax credits and increased margin deposits driven by increases in power prices.
- A $144 million decrease in cash primarily due to the timing of fuel and purchased power revenues and expenses.
- A $95 million decrease in cash due to a discretionary contribution to the qualified pension plan. See Note 8 - Benefit Plans for additional information.

Investing Activities

	Years Ended December 31,		
	2025	2024	2023
		(in millions)	
Construction Expenditures	$ (8,453)	$ (7,631)	$ (7,378)
Acquisitions of Nuclear Fuel	(130)	(140)	(128)
Acquisitions of Generation Facilities	(3,453)	(399)	(155)
Proceeds from Sales of Assets	25	362	1,341
Proceeds from Sale of Equity Method Investment	—	114	—
Other	72	98	53
Net Cash Flows Used for Investing Activities	$ (11,939)	$ (7,596)	$ (6,267)

2025 Compared to 2024

Net Cash Flows Used for Investing Activities increased by $4.3 billion primarily due to the following:

- A $3.1 billion increase in Acquisitions of Generation Facilities.
- An $822 million increase in Construction Expenditures primarily due to increases in Vertically Integrated Utilities of $636 million and Transmission and Distribution Utilities of $634 million partially offset by decreases in Corporate and Other of $429 million driven by expenditures for fuel cell generation assets in 2024.
- A $337 million decrease in Proceeds from Sale of Assets primarily due to the sale of AEP OnSite Partners in 2024.
- A $114 million decrease in Proceeds from the Sale of AEP's Equity Investment in NMRD.

See Note 7 - Acquisitions, Dispositions and Impairments for additional information.

Financing Activities

	Years Ended December 31,		
	2025	2024	2023
		(in millions)	
Issuance of Common Stock	$ 775	$ 552	$ 1,000
Issuance/Retirement of Debt, Net	3,596	2,126	1,985
Principal Payments for Finance Lease Obligations	(51)	(65)	(68)
Proceeds from the Midwest Transmission Holdings Noncontrolling Interest Transaction, Net of Transaction Costs	2,783	—	—
Dividends Paid on Common Stock	(2,008)	(1,898)	(1,752)
Other	(78)	(56)	(88)
Net Cash Flows from Financing Activities	$ 5,017	$ 659	$ 1,077

2025 Compared to 2024

Net Cash Flows from Financing Activities increased by $4.4 billion primarily due to the following:

- A $3.1 billion increase in issuances of long-term debt.
- A $2.8 billion increase due to proceeds from the Midwest Transmission Holdings Noncontrolling Interest transaction. See "Noncontrolling Interest in Midwest Transmission Holdings" section of Note 7 for additional information.

These increases in cash were partially offset by:

- A $964 million increase in retirements of long-term debt.
- A $710 million decrease due to changes in short-term debt.

The following financing activities occurred during 2025:

AEP Common Stock:

- During 2025, AEP issued 8 million shares of common stock under the Forward Sale of Equity, ATM offering program, incentive compensation, employee saving and dividend reinvestment plans. See "Common Stock" section of Note 15 for additional information. AEP received net proceeds of $775 million related to these issuances.

Debt:

- During 2025, AEP issued approximately $8.3 billion of long-term debt, including $3 billion of junior subordinated notes at interest rates ranging from 5.80% to 6.05%, $2.2 billion of other debt at various interest rates, $2.1 billion of senior unsecured notes at interest rates ranging from 5.38% to 5.85%, $478 million of securitization bonds at an interest rate of 5.30%, $320 million of pollution control bonds at interest rates ranging from 3.30% to 3.70% and $203 million of notes payable at various interest rates.
- During 2025, settlements of AEP's interest rate derivatives resulted in net cash paid of $40 million for derivatives designated as fair value hedges. As of December 31, 2025, AEP had a total notional amount of $500 million of outstanding interest rate derivatives designated as fair value hedges.

See "Financing Activities Subsequent Events" section of Note 15 for Long-term debt and other securities issued, retired and principal payments made after December 31, 2025 through February 12, 2026, the date that the 10-K was issued.

BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $12.2 billion of capital expenditures in 2026. For the four-year period, 2027 through 2030, management forecasts capital expenditures of $59.7 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 estimated capital expenditures by Business Segment are as follows:

	2026 Budgeted Capital Expenditures							2027-2030
Segment	**Environmental**	**Generation**	**Renewables**	**Transmission**	**Distribution**	**Other (a)**	**Total**	**Total**
				(in millions)				
VIU	$ 97	$ 2,144	$ 1,173	$ 1,187	$ 1,733	$ 364	$ 6,698	$ 30,457
T&D	—	—	—	1,576	1,683	295	3,554	18,983
AEPTHCo	—	—	—	1,454	—	32	1,486	9,122
G&M	—	—	—	—	—	21	21	91
Corporate and Other	—	117	—	—	—	355	472	1,082
Total	$ 97	$ 2,261	$ 1,173	$ 4,217	$ 3,416	$ 1,067	$12,231	$ 59,735

(a) Amount primarily consists of facilities, software and telecommunications.

The 2026 estimated capital expenditures by Registrant Subsidiary are as follows:

	2026 Budgeted Capital Expenditures						
Company	**Environmental**	**Generation**	**Renewables**	**Transmission**	**Distribution**	**Other (a)**	**Total**
				(in millions)			
AEP Texas	$ —	$ —	$ —	$ 1,208	$ 949	$ 194	$ 2,351
AEPTCo	—	—	—	1,326	—	29	1,355
APCo	58	158	387	358	449	107	1,517
I&M	3	1,237	4	160	362	66	1,832
OPCo	—	—	—	368	734	101	1,203
PSO	4	305	738	172	412	66	1,697
SWEPCo	17	361	44	360	323	106	1,211

(a) Amount primarily consists of facilities, software and telecommunications.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING STANDARDS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on net income or financial condition.

Management discusses the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosures relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in the financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

The Registrants' financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

The Registrants recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, the timing of expense and income recognition is matched with regulated revenues. Liabilities are also recorded for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, regulatory assets are recorded on the balance sheets. Management reviews the probability of recovery at each balance sheet date and whenever new events occur. Similarly, regulatory liabilities are recorded when a determination is made that a refund is probable or when ordered by a commission. Examples of new events that affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs as well as the return of revenues, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, that regulatory asset is written-off as a charge against earnings. A write-off of regulatory assets or establishment of a regulatory liability may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on net income. See Note 5 - Effects of Regulation for additional information related to regulatory assets and regulatory liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

AEP recognizes revenues from customers as the performance obligations of delivering energy to customers are satisfied. The determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. PSO and SWEPCo do not include the fuel portion in unbilled revenue in accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas.

Accrued unbilled revenues for the Vertically Integrated Utilities segment were $387 million and $351 million as of December 31, 2025 and 2024, respectively. The changes in unbilled electric utility revenues for AEP's Vertically Integrated Utilities segment were $36 million, $63 million and $(66) million for the years ended December 31, 2025, 2024 and 2023, respectively. The changes in unbilled electric revenues are primarily due to changes in weather, rates and usage.

Accrued unbilled revenues for the Transmission and Distribution Utilities segment were $206 million and $199 million as of December 31, 2025 and 2024, respectively. The changes in unbilled electric utility revenues for AEP's Transmission and Distribution Utilities segment were $7 million, $8 million and $(30) million for the years ended December 31, 2025, 2024 and 2023, respectively. The changes in unbilled electric revenues are primarily due to changes in weather, rates and usage.

Accrued unbilled revenues for the Generation & Marketing segment were $159 million and $121 million as of December 31, 2025 and 2024, respectively. The changes in unbilled electric utility revenues for AEP's Generation & Marketing segment were $38 million, $10 million and $2 million for the years ended December 31, 2025, 2024 and 2023, respectively.

Assumptions and Approach Used

For each Registrant except AEPTCo, the monthly estimate for unbilled revenues is based upon a primary computation of net generation (generation plus purchases less sales) less the current month's billed KWhs and estimated line losses, plus the prior month's unbilled KWhs. However, due to the potential for meter reading issues, meter drift and other anomalies, a secondary computation is made, based upon an allocation of billed KWhs to the current month and previous month, on a billing cycle-by-cycle basis, and by dividing the current month aggregated result by the billed KWhs. The two methodologies are evaluated to confirm that they are not statistically different.

For AEP's Generation & Marketing segment, management calculates unbilled revenues based on a primary computation of load as provided by PJM less the current month's billed KWhs and estimated line losses, plus the prior month's unbilled KWhs. However, due to the potential for meter reading issues, meter drift and other anomalies, a secondary computation is made, based upon using the most recent historic daily activity on a per contract basis. The two methodologies are evaluated to confirm that they are not statistically different.

Effect if Different Assumptions Used

For each Registrant except AEPTCo, if the two methodologies used to estimate unbilled revenue are statistically different, a limiter adjustment is made to bring the primary computation within one standard deviation of the secondary computation.

Additionally, significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the estimate of unbilled revenue.

Accounting for Derivative Instruments

Nature of Estimates Required

Management considers fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

The Registrants measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based primarily on exchange prices and broker quotes. If a quoted market price is not available, the fair value is estimated based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include forward market price assumptions.

The Registrants reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. Liquidity adjustments are calculated by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. Credit adjustments on risk management contracts are calculated using estimated default probabilities and recovery rates relative to the counterparties or counterparties with similar credit profiles and contractual netting agreements.

With respect to hedge accounting, management assesses hedge effectiveness and evaluates a forecasted transaction's probability of occurrence within the specified time period as provided in the original hedge documentation.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into Operating Income.

For additional information see Note 10 - Derivatives and Hedging and Note 11 - Fair Value Measurements. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for AEP's fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance and "Regulated Operations" accounting guidance, the Registrants evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable. Such events or changes in circumstance include planned abandonments, probable disallowances for ratemaking purposes of assets determined to be recently completed plant and assets that meet the held-for-sale criteria. The Registrants utilize a group composite method of depreciation to estimate the useful lives of long-lived assets.

An impairment evaluation of a long-lived, held and used asset may result from an abandonment, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the book value of the asset is not recoverable through estimated, future undiscounted cash flows, the Registrants record an impairment to the extent that the fair value of the asset is less than its book value. Performing an impairment evaluation involves a significant degree of estimation and judgment in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets and developing the non-discounted and discounted future cash flows (used to estimate fair value in the absence of market-based value, in some instances) associated with the asset. Assets held for sale must be measured at the lower of the book value or fair value less cost to sell. An impairment is recognized if an asset's fair value less costs to sell is less than its book value. Any impairment charge is recorded as a reduction to earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, the Registrants estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. Cash flow estimates are based on relevant information available at the time the estimates are made. Estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. Also, when measuring fair value, management evaluates the characteristics of the asset or liability to determine if market participants would take those characteristics into account when pricing the asset or liability at the measurement date. Such characteristics include, for example, the condition and location of the asset or restrictions on the use of the asset. The Registrants perform depreciation studies that include a review of any external factors that may affect the useful life to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions for regulated assets. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of the asset can vary if different estimates and assumptions are used in the applied valuation techniques. Estimates for depreciation rates contemplate the history of interim capital replacements and the amount of salvage expected. In cases of impairment, the best estimate of fair value was made using valuation methods based on the most current information at that time. Differences in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, the timing and terms of the transactions and management's analysis of the benefits of the transaction.

Pension and OPEB

AEPSC maintains a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, non-qualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law for participants in the Qualified Plan (collectively the Pension Plans). AEPSC also sponsors OPEB plans to provide health and life insurance benefits for retired employees. The Pension Plans and OPEB plans are collectively referred to as the Plans.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1. See Note 8 - Benefit Plans for information regarding costs and assumptions for the Plans.

The following table shows the net periodic cost (credit) of the Plans:

	Years Ended December 31,		
Net Periodic Cost (Credit)	**2025**	**2024**	**2023**
		(in millions)	
Pension Plans	$ 42	$ 86	$ (24)
OPEB	(78)	(71)	(107)

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2026, management evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Management also considered historical returns of the investment markets and tax rates which affect a portion of the OPEB plans' assets. Management anticipates that the investment managers employed for the Plans will invest the assets to generate future returns averaging 6.75% for the Qualified Plan and 6% for the OPEB plans.

The expected long-term rate of return on the Plans' assets is based on management's targeted asset allocation and expected investment returns for each investment category. Assumptions for the Plans are summarized in the following table:

	Pension Plans		**OPEB**	
	2026 Target Asset Allocation	**Assumed/Expected Long-Term Rate of Return**	**2026 Target Asset Allocation**	**Assumed/Expected Long-Term Rate of Return**
Equity	35 %	8.50 %	63 %	7.52 %
Fixed Income	49 %	5.31 %	36 %	4.56 %
Other Investments	15 %	8.78 %	—	—
Cash and Cash Equivalents	1 %	3.00 %	1 %	3.00 %
Total	100 %		100 %	

Management regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation. Management believes that 6.75% for the Qualified Plan and 6% for the OPEB plans are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 10.52% and an actual gain of 2.59% for the years ended December 31, 2025 and 2024, respectively. The OPEB plans' assets had an actual gain of 14.72% and an actual gain of 8.98% for the years ended December 31, 2025 and 2024, respectively. Management will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

AEP bases the determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2025, AEP had cumulative losses of approximately $196 million for the Qualified Plan that remain to be recognized in the calculation of the market-related value of assets. These unrecognized market-related net actuarial losses may result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that AEP utilizes for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate as of December 31, 2025 under this method was 5.5% for the Qualified Plan, 5.3% for the Nonqualified Plans and 5.5% for the OPEB plans. Due to the effect of the unrecognized net actuarial losses and based on an expected rate of return, discount rates and various other assumptions, management estimates costs (credits) for the Pension Plans will approximate \$87 million, \$139 million and \$142 million in 2026, 2027 and 2028, respectively. Based on an expected rate of return discount rate and various other assumptions, management estimates OPEB plan credits will approximate \$90 million, \$85 million and \$91 million in 2026, 2027 and 2028, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

The value of AEP's Pension Plans' assets is \$3.8 billion as of December 31, 2025 and \$3.7 billion as of December 31, 2024. During 2025, the Qualified Plan paid \$374 million and the Nonqualified Plans paid \$8 million in benefits to plan participants. The value of AEP's OPEB plans' assets increased to \$2.0 billion as of December 31, 2025 from \$1.8 billion as of December 31, 2024 primarily due to positive investment returns. During 2025, the OPEB plans paid \$105 million in benefits to plan participants.

Nature of Estimates Required

AEPSC sponsors pension and OPEB plans in various forms covering all employees who meet eligibility requirements. These benefits are accounted for under "Compensation" and "Plan Accounting" accounting guidance. The measurement of pension and OPEB obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates includes discount rate, compensation increase rate, cash balance crediting rate, health care cost trend rate and expected return on plan assets. Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and OPEB expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		OPEB	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in millions)			
Effect on December 31, 2025 Benefit Obligations				
Discount Rate	\$ (164)	\$ 179	\$ (23)	\$ 25
Compensation Increase Rate	23	(22)	NA	NA
Cash Balance Crediting Rate	48	(45)	NA	NA
Health Care Cost Trend Rate	NA	NA	5	(5)
Effect on 2025 Periodic Cost				
Discount Rate	\$ (9)	\$ 10	\$ (1)	\$ 1
Compensation Increase Rate	6	(5)	NA	NA
Cash Balance Crediting Rate	11	(10)	NA	NA
Health Care Cost Trend Rate	NA	NA	1	(1)
Expected Return on Plan Assets	(20)	20	(9)	9

NA Not applicable.

Asset Retirement Obligations – Impact of the 2024 CCR Rule

Nature of Estimates Required

In April 2024, the Federal EPA finalized revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land. Accounting for the incremental asset retirement obligation arising from the revised CCR Rule requires significant judgment by management due to the significant measurement uncertainty in estimating the incremental liability. As a result of the rule, AEP recorded an incremental ARO of $674 million in the second quarter of 2024.

Assumptions and Approach Used

AROs are computed as the present value of the estimated costs associated with the future retirement of an asset and are recorded in the period in which the liability is incurred. Projections of the timing and amounts of future cash outlays are based on estimation of the extent and quantity of coal ash present at sites, projections of the when and how the liabilities will be remediated as well as the rate at which costs will escalate over time and discount rate, which may change significantly over time.

Effect if Different Assumptions Used

As further groundwater monitoring and other analysis is performed, management expects to refine the assumptions and underlying cost estimates used in recording the incremental asset retirement obligation arising from the revised CCR Rule. The estimated liability can significantly change if there are changes in the impacted coal ash site acreage inputs or if refinements in the assumptions over the remediation costs for legacy CCR surface impoundments and CCR management units, including assumptions over future groundwater monitoring requirements vary from the initial estimates. These future changes could have a material impact on the ARO and materially reduce future net income, cash flows and financial condition if AEP cannot ultimately recover these additional costs of compliance. See Note 6 – Commitments, Guarantees and Contingencies and Note 19 – Property, Plant and Equipment for additional information related to AROs and the CCR Rule.

ACCOUNTING STANDARDS

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

Market risk evaluations are subject to certain limitations that may prevent a full reflection of the net market risk exposure. These limitations primarily relate to model and data constraints that rely on hypothetical assumptions and may not capture all potential future market conditions. These include the use of historical information, assumptions about market volatility and correlations, and dependence on observable inputs that may not be available for less liquid positions. As a result, the actual impact of market movements could differ from the estimates presented.

The Vertically Integrated Utilities segment is exposed to certain market risks as a major power producer and through transactions in power, coal, natural gas and marketing contracts. These risks include commodity price risks which may be subject to capacity risk, credit risk as well as interest rate risk. These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates.

The Transmission and Distribution Utilities segment is exposed to energy procurement risk and interest rate risk.

The Generation & Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risks which may be subject to capacity risk, credit risk as well as interest rate risk. These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates. In addition, the Generation & Marketing segment is also exposed to certain market risks as a power producer and through transactions in wholesale electricity, natural gas and marketing contracts.

Management employs risk management contracts including physical forward and financial forward purchase-and-sale contracts. Management engages in risk management of power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. As a result, AEP is subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the AEP Board. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Regulated Risk Committee and the Energy Supply Risk Committee (Competitive Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Financial Officer, Executive Vice President and Chief Commercial Officer, Senior Vice President and Treasurer, Senior Vice President of Regulated Commercial Operations, President AEP Transmission, and Senior Vice President Finance. The Competitive Risk Committee consists of AEPSC's Chief Financial Officer, Executive Vice President and Chief Commercial Officer, Senior Vice President and Treasurer, and Senior Vice President of Competitive Commercial Operations. If commercial activities result in predetermined limits being exceeded, positions are modified to reduce the risk to be within the limits unless specifically approved by the respective committee.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2024:

MTM Derivative Contract Net Assets (Liabilities)

Year Ended December 31, 2025

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contracts - Commodity Net Assets (Liabilities) as of December 31, 2024	$ 92	$ (48)	$ 162	$ 206
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(79)	2	(39)	(116)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	12	12
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(10)	—	73	63
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	140	13	—	153
Total MTM Risk Management Contracts - Commodity Net Assets (Liabilities) as of December 31, 2025	$ 143	$ (33)	$ 208	$ 318
Commodity Cash Flow Hedge Contracts				98
Fair Value Hedge Contracts				(29)
Collateral Deposits				(80)
Total MTM Derivative Contract Net Assets as of December 31, 2025				$ 307

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

See Note 10 – Derivatives and Hedging and Note 11 – Fair Value Measurements for additional information related to risk management contracts. The following tables and discussion provide information on credit risk and market volatility risk.

Credit Risk

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

AEP has risk management contracts (including non-derivative contracts) with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of December 31, 2025, credit exposure net of collateral to sub-investment grade counterparties was approximately 10.6%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss).

As of December 31, 2025, the following table approximates AEP's counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$ 564	$ 76	$ 488	3	$ 301
Non-investment Grade	5	1	4	2	4
No External Ratings:					
Internal Investment Grade	18	—	18	3	12
Internal Non-investment Grade	126	70	56	2	48
Total as of December 31, 2025	$ 713	$ 147	$ 566		

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

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

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of December 31, 2025, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

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

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

VaR Model
Trading Portfolio

Twelve Months Ended December 31, 2025				Twelve Months Ended December 31, 2024			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ —	$ 1	$ —	$ —	$ —	$ 2	$ —	$ —

VaR Model
Non-Trading Portfolio

Twelve Months Ended December 31, 2025				Twelve Months Ended December 31, 2024			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 4	$ 29	$ 8	$ 2	$ 38	$ 99	$ 19	$ 8

Management back-tests VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

As the VaR calculation captures recent price movements, management also performs regular stress testing of the trading portfolio to understand AEP's exposure to extreme price movements. A historical-based method is employed whereby the current trading portfolio is subjected to actual, observed price movements from the last several years in order to ascertain which historical price movements translated into the largest potential MTM loss. Management then researches the underlying positions, price movements and market events that created the most significant exposure and reports the findings to the Risk Executive Committee, Regulated Risk Committee or Competitive Risk Committee as appropriate.

Interest Rate Risk

AEP is exposed to interest rate market fluctuations in the normal course of business operations. Prior to 2022, interest rates remained at low levels and the Federal Reserve maintained the federal funds target range at 0.0% to 0.25% for much of 2021. During 2022 and 2023, the Federal Reserve approved 11 rate increases for a total cumulative increase of 5.25%. In light of the progress on inflation and the balance of risks, the Federal Reserve authorized three rate cuts in 2024, totaling a cumulative decrease of 1.0%. In 2025, the Federal Reserve authorized three additional interest rate cuts, totaling a cumulative 0.75%. AEP has outstanding short and long-term debt which is subject to variable rates. AEP manages interest rate risk by limiting variable-rate exposures to a percentage of total debt, by entering into interest rate derivative instruments and by monitoring the effects of market changes on interest rates. For the twelve months ended December 31, 2025, 2024 and 2023, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $36 million, $33 million and $40 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries (the "Company") as of December 31, 2025 and 2024, and the related consolidated statements of income, of comprehensive income (loss), of changes in equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes and financial statement schedules listed in the index appearing under Item 15(a)(2) (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Accounting for the Effects of Cost-Based Regulation

As described in Notes 1 and 5 to the consolidated financial statements, the Company's consolidated financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and matching income with its passage to customers in cost-based regulated rates. As of December 31, 2025, there were $5,230 million of deferred costs included in regulatory assets, $1,307 million of which were pending final regulatory approval, and $8,426 million of regulatory liabilities awaiting potential refund or future rate reduction, $119 million of which were pending final regulatory determination. Management reviews the probability of recovery of regulatory assets and refund of regulatory liabilities at each balance sheet date and whenever new events occur, such as changes in the regulatory environment, issuance of regulatory commission orders, or passage of new legislation.

The principal considerations for our determination that performing procedures relating to the accounting for the effects of cost-based regulation is a critical audit matter are (i) the significant judgment by management in assessing probability of the recovery of regulatory assets and refund of regulatory liabilities and (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to the probability of recovery of regulatory assets and refund of regulatory liabilities.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's evaluation of new events, such as changes in the regulatory environment, issuance of regulatory commission orders, or passage of new legislation, including controls over the probability of recovery of regulatory assets and refund of regulatory liabilities. These procedures also included, among others (i) evaluating the reasonableness of management's assessment of probability of future recovery for regulatory assets and refund of regulatory liabilities; (ii) testing, on a sample basis, the regulatory assets and liabilities, including those subject to pending rate cases and regulatory proceedings, by considering (a) the provisions and formulas outlined in rate orders; (b) other regulatory correspondence; and (c) application of relevant regulatory precedents.

Valuation of Level 3 Energy Contracts

As described in Notes 1, 10 and 11 to the consolidated financial statements, the Company employs risk management commodity contracts including physical and financial forward purchase and sale contracts and, to a lesser extent, over-the-counter swaps and options to accomplish its risk management strategies. Certain over-the-counter and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. As disclosed by management, the fair value of these risk management commodity contracts is estimated based on the best market information available, including valuation models that estimate future energy prices based on existing market and broker quotes, and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment including forward market price assumptions. Risk management commodity contracts are substantially comprised of energy contracts. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. Management utilized a forward market price assumption to value its level 3 energy contracts. The Company’s level 3 energy contracts assets and liabilities totaled $224 million and $144 million, respectively, as of December 31, 2025.

The principal considerations for our determination that performing procedures relating to the valuation of Level 3 energy contracts is a critical audit matter are (i) the significant judgment by management when developing the fair value estimate of the level 3 energy contracts; (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to management's significant assumption relating to the forward market price; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's valuation of the level 3 risk management commodity contracts, including energy contracts. These procedures also included, among others (i) testing the completeness and accuracy of the underlying data provided by management; (ii) testing management's process for developing the fair value of the level 3 energy contracts; (iii) evaluating the appropriateness of the valuation models used in developing the fair value estimate of the level 3 energy contracts; and (iv) the involvement of professionals with specialized skill and knowledge to assist in evaluating the reasonableness of the forward market price assumption.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 12, 2026

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and Subsidiary Companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2025. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded AEP's internal control over financial reporting was effective as of December 31, 2025.

PricewaterhouseCoopers LLP, AEP's independent registered public accounting firm has issued an audit report on the effectiveness of AEP's internal control over financial reporting as of December 31, 2025. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2025, 2024 and 2023
(in millions, except per-share and share amounts)

	Years Ended December 31, 2025	2024	2023
REVENUES			
Vertically Integrated Utilities	$ 12,556	$ 11,414	$ 11,304
Transmission and Distribution Utilities	6,097	5,880	5,677
Generation & Marketing	2,697	1,945	1,543
Other Revenues	526	482	458
TOTAL REVENUES	21,876	19,721	18,982
EXPENSES			
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	7,031	5,936	6,578
Other Operation	2,950	3,127	2,811
Maintenance	1,499	1,325	1,276
Asset Impairments and Other Related Charges	66	143	86
Loss on the Sale of the Competitive Contracted Renewables Portfolio	—	—	93
Depreciation and Amortization	3,380	3,290	3,090
Taxes Other Than Income Taxes	1,631	1,596	1,492
TOTAL EXPENSES	16,557	15,417	15,426
OPERATING INCOME	5,319	4,304	3,556
Other Income (Expense):			
Other Income	48	65	64
Allowance for Equity Funds Used During Construction	245	211	175
Non-Service Cost Components of Net Periodic Benefit Cost	138	126	221
Interest Expense	(2,026)	(1,863)	(1,807)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	3,724	2,843	2,209
Income Tax Expense (Benefit)	129	(39)	55
Equity Earnings of Unconsolidated Subsidiaries	101	94	59
NET INCOME	3,696	2,976	2,213
Net Income Attributable to Noncontrolling Interests	116	9	5
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3,580	$ 2,967	$ 2,208
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	534,535,444	530,092,672	518,903,682
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 6.70	$ 5.60	$ 4.26
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	537,467,865	531,337,703	520,206,258
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 6.66	$ 5.58	$ 4.24

See Notes to Financial Statements of Registrants beginning on page 70.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Years Ended December 31,		
	2025	2024	2023
Net Income	$ 3,696	$ 2,976	$ 2,213
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(7), $1 and $(34) in 2025, 2024 and 2023, Respectively	(25)	5	(127)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0, $(1) and $(3) in 2025, 2024 and 2023, Respectively	1	(3)	(13)
Pension and OPEB Funded Status, Net of Tax of $17, $11 and $(4) in 2025, 2024 and 2023, Respectively	63	41	(16)
Recognition of Pension Settlement Costs, Net of Tax of $—, $2, and $0 in 2025, 2024 and 2023, Respectively	—	9	—
Reclassifications of KPCo Pension and OPEB Regulatory Assets, Net of Tax of $0, $0 and $4 in 2025, 2024 and 2023, Respectively	—	—	17
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	39	52	(139)
TOTAL COMPREHENSIVE INCOME	3,735	3,028	2,074
Total Comprehensive Income Attributable To Noncontrolling Interests	116	9	5
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3,619	$ 3,019	$ 2,069

See Notes to Financial Statements of Registrants beginning on page 70.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2022	525	$ 3,413	$ 8,051	$ 12,346	$ 84	$ 229	$ 24,123
Issuance of Common Stock	2	15	985				1,000
Common Stock Dividends				(1,752) (a)			(1,752)
Dividends Paid to Noncontrolling Interest						(8)	(8)
Other Changes in Equity			38	(2)		(1)	35
Disposition of Competitive Contracted Renewables Portfolio						(186)	(186)
Net Income				2,208		5	2,213
Other Comprehensive Loss					(139)		(139)
TOTAL EQUITY – DECEMBER 31, 2023	527	3,428	9,074	12,800	(55)	39	25,286
Issuance of Common Stock	7	44	508				552
Common Stock Dividends				(1,898) (a)			(1,898)
Dividends Paid to Noncontrolling Interest						(6)	(6)
Other Changes in Equity			24				24
Net Income				2,967		9	2,976
Other Comprehensive Income					52		52
TOTAL EQUITY – DECEMBER 31, 2024	534	3,472	9,606	13,869	(3)	42	26,986
Issuance of Common Stock	8	51	724				775
Capital Contribution from Noncontrolling Interest						38	38
Common Stock Dividends				(2,008) (a)			(2,008)
Dividends Paid to Noncontrolling Interest						(108)	(108)
Other Changes in Equity			17				17
Midwest Transmission Holdings Noncontrolling Interest Transaction			1,791			992	2,783
Net Income				3,580		116	3,696
Other Comprehensive Income					39		39
TOTAL EQUITY – DECEMBER 31, 2025	542	$ 3,523	$ 12,138	$ 15,441	$ 36	$ 1,080	$ 32,218

(a) Cash dividends declared per AEP common share were \$3.74, \$3.57 and \$3.37 for the years ended December 31, 2025, 2024 and 2023, respectively.

See Notes to Financial Statements of Registrants beginning on page 70.

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

	December 31, 2025	December 31, 2024
CURRENT ASSETS		
Cash and Cash Equivalents	$ 197	$ 203
Restricted Cash (December 31, 2025 and 2024 Amounts Include $71 and $43, Respectively, Related to Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding, Storm Recovery Funding and Cost Recovery Funding)	71	43
Other Temporary Investments (December 31, 2025 and 2024 Amounts Include $209 and $207, Respectively, Related to EIS)	220	215
Accounts Receivable:		
Customers	1,166	1,100
Accrued Unbilled Revenues	421	367
Pledged Accounts Receivable – AEP Credit	1,272	1,162
Miscellaneous	60	64
Allowance for Credit Losses	(52)	(61)
Total Accounts Receivable	2,867	2,632
Fuel	576	749
Materials and Supplies	1,046	966
Risk Management Assets	352	210
Accrued Tax Benefits	85	38
Regulatory Asset for Under-Recovered Fuel Costs	426	446
Prepayments and Other Current Assets	212	287
TOTAL CURRENT ASSETS	6,052	5,789
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	28,388	24,830
Transmission	42,557	38,872
Distribution	33,364	31,062
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	8,635	7,491
Construction Work in Progress	7,635	6,347
Total Property, Plant and Equipment	120,579	108,602
Accumulated Depreciation and Amortization	28,205	26,186
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	92,374	82,416
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,804	5,129
Securitized Assets	933	554
Spent Nuclear Fuel and Decommissioning Trusts	4,916	4,395
Goodwill	53	53
Long-term Risk Management Assets	265	289
Operating Lease Assets	661	580
Deferred Charges and Other Noncurrent Assets	4,402	3,873
TOTAL OTHER NONCURRENT ASSETS	16,034	14,873
TOTAL ASSETS	$ 114,460	$ 103,078

See Notes to Financial Statements of Registrants beginning on page 70.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2025 and 2024
(dollars in millions)

	December 31, 2025	December 31, 2024
CURRENT LIABILITIES		
Accounts Payable	$ 3,429	$ 2,638
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	900	900
Other Short-term Debt	608	1,624
Total Short-term Debt	1,508	2,524
Long-term Debt Due Within One Year (December 31, 2025 and 2024 Amounts Include $207 and $217, Respectively, Related to DCC Fuel, Restoration Funding, Appalachian Consumer Rate Relief Funding, Storm Recovery Funding, Transource Energy and Cost Recovery Funding)	3,194	3,335
Risk Management Liabilities	132	100
Customer Deposits	507	455
Accrued Taxes	2,002	1,922
Accrued Interest	544	453
Obligations Under Operating Leases	100	92
Other Current Liabilities	1,898	1,490
TOTAL CURRENT LIABILITIES	13,314	13,009
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2025 and 2024 Amounts Include $1,294 and $827, Respectively, Related to DCC Fuel, Restoration Funding, Appalachian Consumer Rate Relief Funding, Storm Recovery Funding, Transource Energy and Cost Recovery Funding)	44,128	39,308
Long-term Risk Management Liabilities	178	224
Deferred Income Taxes	10,951	9,972
Regulatory Liabilities and Deferred Investment Tax Credits	8,362	8,344
Asset Retirement Obligations	3,556	3,531
Employee Benefits and Pension Obligations	232	361
Obligations Under Operating Leases	578	504
Deferred Credits and Other Noncurrent Liabilities	905	801
TOTAL NONCURRENT LIABILITIES	68,890	63,045
TOTAL LIABILITIES	82,204	76,054
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
Contingently Redeemable Performance Share Awards	38	38
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2025	2024
Shares Authorized	600,000,000	600,000,000
Shares Issued	542,048,288	534,094,530

	2025	2024
(1,186,815 Shares were Held in Treasury as of December 31, 2025 and 2024, Respectively)	3,523	3,472
Paid-in Capital	12,138	9,606
Retained Earnings	15,441	13,869
Accumulated Other Comprehensive Income (Loss)	36	(3)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	31,138	26,944
Noncontrolling Interests	1,080	42
TOTAL EQUITY	32,218	26,986
TOTAL LIABILITIES AND EQUITY	$ 114,460	$ 103,078

See Notes to Financial Statements of Registrants beginning on page 70.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Years Ended December 31, 2025	2024	2023
OPERATING ACTIVITIES			
Net Income	$ 3,696	$ 2,976	$ 2,213
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	3,380	3,290	3,090
Deferred Income Taxes	311	58	185
Loss on the Sale of the Competitive Contracted Renewables Portfolio	—	—	93
Asset Impairments and Other Related Charges	66	143	86
Allowance for Equity Funds Used During Construction	(245)	(211)	(175)
Mark-to-Market of Risk Management Contracts	(116)	(81)	9
Amortization of Nuclear Fuel	109	103	97
Pension Contributions to Qualified Plan Trust	(95)	—	—
Property Taxes	(42)	(45)	(41)
Deferred Fuel Over/Under-Recovery, Net	133	277	893
Change in Regulatory Assets	(304)	(174)	(316)
Change in Other Noncurrent Assets	(559)	(348)	(446)
Change in Other Noncurrent Liabilities	269	306	29
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(246)	(156)	236
Fuel, Materials and Supplies	115	172	(504)
Accounts Payable	252	85	(253)
Accrued Taxes, Net	32	240	22
Other Current Assets	85	(13)	(44)
Other Current Liabilities	103	182	(162)
Net Cash Flows from Operating Activities	6,944	6,804	5,012
INVESTING ACTIVITIES			
Construction Expenditures	(8,453)	(7,631)	(7,378)
Purchases of Investment Securities	(2,981)	(2,923)	(2,864)
Sales of Investment Securities	2,935	2,878	2,795
Acquisitions of Nuclear Fuel	(130)	(140)	(128)
Acquisitions of Generation Facilities	(3,453)	(399)	(155)
Proceeds from Sales of Assets	25	362	1,341
Proceeds from Sale of Equity Method Investment	—	114	—
Other Investing Activities	118	143	122
Net Cash Flows Used for Investing Activities	(11,939)	(7,596)	(6,267)
FINANCING ACTIVITIES			
Capital Contribution from Noncontrolling Interest	38	—	—
Issuance of Common Stock, Net	775	552	1,000
Issuance of Long-term Debt	8,261	5,117	5,463
Issuance of Short-term Debt with Original Maturities greater than 90 Days	320	724	1,070
Change in Short-term Debt with Original Maturities less than 90 Day, Net	(658)	(159)	(1,223)
Retirement of Long-term Debt	(3,649)	(2,685)	(2,196)
Redemption of Short-term Debt with Original Maturities greater than 90 Days	(678)	(871)	(1,129)
Principal Payments for Finance Lease Obligations	(51)	(65)	(68)
Proceeds from the Midwest Transmission Holdings Noncontrolling Interest Transaction, Net of Transaction Costs	2,783	—	—
Dividends Paid on Common Stock	(2,008)	(1,898)	(1,752)
Dividends Paid on Noncontrolling Interest	(108)	(6)	(8)
Other Financing Activities	(8)	(50)	(80)
Net Cash Flows from Financing Activities	5,017	659	1,077
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	22	(133)	(178)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	246	379	557
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 268	$ 246	$ 379

See Notes to Financial Statements of Registrants beginning on page 70.

INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANTS

The notes to 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. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

ORGANIZATION

The Registrants engage in the generation, transmission and distribution of electric power. The Registrant Subsidiaries that conduct most of these activities are regulated by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with the FERC and other regulatory guidelines. Most of these companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

AEP also provides competitive electric and gas supply for residential, commercial and industrial customers in deregulated electricity markets. The Registrants also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States and provide various energy-related services. I&M provides barging services to both affiliated and nonaffiliated companies.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

AEP's public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in the eleven state operating territories in which they operate. The FERC also regulates the Registrants' affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over certain issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. The Registrants' wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when a cost-based contract is negotiated and filed with the FERC or the FERC determines that the Registrants have "market power" in the region where the transaction occurs. Wholesale power supply contracts have been entered into with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued-up to actual costs annually.

The state regulatory commissions regulate all of the retail distribution operations and rates of AEP's retail public utility subsidiaries on a cost basis. The state regulatory commissions also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. For generation in Ohio, customers who have not switched to a CRES provider for generation receive SSO from OPCo and pay market-based auction rates. In the ERCOT region of Texas, AEP Texas customers are required to choose an REP for generation service and pay market-based rates.

The FERC also regulates the Registrants' wholesale transmission operations and rates. Retail transmission rates are based upon the FERC OATT rate when retail rates are unbundled in connection with restructuring. Retail transmission rates are based on formula rates included in the PJM OATT that are cost-based and are unbundled in Ohio for OPCo, in Virginia for APCo and in Michigan for I&M. AEP Texas' retail transmission rates in Texas are unbundled but the retail transmission rates are regulated, on a cost basis, by the PUCT. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions. Transmission rates for AEPTCo's seven wholly-owned transmission subsidiaries within the AEP Transmission Holdco segment are based on formula rates included in the applicable RTO's OATT that are cost-based.

In West Virginia, APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a combined cost-of-service basis.

In addition, the FERC regulates the Operating Agreement, TA and TCA, all of which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. The FERC also regulates the PCA. See Note 17 - Related Party Transactions for additional information.

Principles of Consolidation

AEP and the Registrant Subsidiaries' consolidated financial statements include wholly-owned subsidiaries and VIEs, of which AEP or a Registrant Subsidiary is the primary beneficiary. Intercompany items are eliminated in consolidation.

The equity method of accounting is used for equity investments where the Registrants exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. The proportionate share of the investee's equity earnings or losses is included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income.

AEP, I&M, PSO and SWEPCo have undivided ownership interests in generating units that are jointly-owned. The proportionate share of the operating costs associated with such facilities is included on the income statements and the assets and liabilities are reflected on the balance sheets. See Note 18 - Variable Interest Entities and Equity Method Investments and Note 19 - Property, Plant and Equipment for additional information.

Accounting for the Effects of Cost-Based Regulation

The Registrants' financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for credit losses, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, AROs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

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 statement of cash flows:

	AEP		AEP Texas		APCo		SWEPCo	
	Year Ended December 31,							
	2025	2024	2025	2024	2025	2024	2025	2024
	(in millions)							
Cash and Cash Equivalents	$ 197	$ 203	$ —	$ —	$ 5	$ 4	$ 2	$ 2
Restricted Cash	71	43	14	24	18	16	15	3
Total Cash, Cash Equivalents and Restricted Cash	$ 268	$ 246	$ 14	$ 24	$ 23	$ 20	$ 17	$ 5

Other Temporary Investments (Applies to AEP)

Other Temporary Investments primarily include marketable securities and investments by its protected cell of EIS. These securities have readily determinable fair values and are carried at fair value with changes in fair value recognized in net income. The cost of securities sold is based on the specific identification or weighted-average cost method. See "Fair Value Measurements of Other Temporary Investments" section of Note 11 for additional information.

Inventory

Fossil fuel inventories are carried at average cost with the exception of AGR, which carries these inventories at the lower of average cost or net realizable value. Materials and supplies inventories are carried at average cost.

Accounts Receivable and Allowance for Credit Losses

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized over time as the performance obligations of delivering energy to customers are satisfied. To the extent that deliveries have occurred but a bill has not been issued, the Registrants accrue and recognize, as Accrued Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from bank conduits for a portion of its interests in the billed and unbilled receivables acquired from the affiliated utility subsidiaries. See "Securitized Accounts Receivable – AEP Credit" section of Note 15 for additional information.

Generally, AEP Credit recognizes bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. The assessment is performed separately for each participating AEP subsidiary, which inherently contemplates any differences in geographical risk characteristics for the allowance for credit losses. For receivables related to APCo's West Virginia operations, the allowance for credit losses is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable.

For customer accounts receivables relating to risk management activities, accounts receivable are reviewed for potential credit losses at a specific counterparty level basis. For AEP Texas, allowances for credit losses are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. For miscellaneous accounts receivable, bad debt expense is recognized based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable, unless specifically identified.

In addition to these processes, management contemplates available current information, as well as any reasonable and supportable forecast information, to determine if allowances for credit losses should be further adjusted in accordance with the accounting guidance for "Credit Losses." Management's assessments contemplate expected losses over the life of the accounts receivable.

Concentrations of Credit Risk and Significant Customers (Applies to Registrant Subsidiaries)

APCo, I&M, OPCo, PSO and SWEPCo do not have any significant customers that comprise 10% or more of their operating revenues. AEP Texas had significant customers which account for the following percentages of Total Revenues for the years ended December 31 and Accounts Receivable – Customers as of December 31:

Significant Customers of AEP Texas: NRG Energy and Vistra Corp	**2025**	**2024**	**2023**
Percentage of Total Revenues	38 %	40 %	41 %
Percentage of Accounts Receivable – Customers	33 %	37 %	34 %

AEPTCo had significant transactions with AEP Subsidiaries which on a combined basis account for the following percentages of Total Revenues for the years ended December 31 and Total Accounts Receivable as of December 31:

Significant Customers of AEPTCo: AEP Subsidiaries	**2025**	**2024**	**2023**
Percentage of Total Revenues	81 %	80 %	79 %
Percentage of Total Accounts Receivable	62 %	69 %	60 %

The Registrant Subsidiaries monitor credit levels and the financial condition of their customers on a continuous basis to minimize credit risk. The regulatory commissions allow recovery in rates for a reasonable level of bad debt costs. Management believes adequate provisions for credit loss have been made in the accompanying Registrant Subsidiary financial statements.

Renewable Energy Credits (Applies to all Registrants except AEP Texas and AEPTCo)

In regulated jurisdictions, the Registrants record renewable energy credits (RECs) at cost. For RECs acquired in AEP's nonregulated operations within the Generation & Marketing segment, management records those RECs at the lower of cost or net realizable value. The Registrants follow the inventory model for these RECs. RECs are reported in Materials and Supplies on the balance sheets. The purchases and sales of RECs are reported in the Operating Activities section of the statements of cash flows. RECs that are consumed to meet applicable state renewable portfolio standards are recorded in Purchased Electricity, Fuel and Other Consumables Used for Electric Generation at an average cost on the statements of income. The net margin on sales of RECs affects the determination of deferred fuel and REC costs.

Property, Plant and Equipment

Regulated

Electric utility property, plant and equipment for rate-regulated operations are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of removal cost incurred and salvage received. These rates and the related lives are subject to periodic review. Removal costs accrued are typically recorded as regulatory liabilities when the revenue received for removal costs accrued exceeds actual removal costs incurred. The removal costs liability is relieved as removal costs are incurred. A regulatory asset balance will occur if actual removal costs incurred exceed accumulated removal costs accrued.

The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are included in operating expenses.

Nuclear fuel, including nuclear fuel in the fabrication phase, is included in Other Property, Plant and Equipment on the balance sheets.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in-service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed or is not probable, the cost of that asset shall be written down to its then current estimated fair value, with the change charged to expense, and the asset is removed from plant-in-service or CWIP.

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Nonregulated

Nonregulated operations generally follow the policies of rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations are stated at original cost (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. A gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense when incurred.

Allowance for Funds Used During Construction and Interest Capitalization

For regulated operations, AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. The Registrants record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense on the statements of income. For nonregulated operations, including certain generating assets, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest."

Asset Retirement Obligations (Applies to all Registrants except AEPTCo)

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. I&M records ARO for the decommissioning of the Cook Plant. Certain registrants also record AROs related to the Federal EPA's revised CCR Rule. For operating facilities, the present value of the liability is added to the cost of the associated asset and depreciated over the remaining life of the asset. For retired facilities, the present value of the liability is expensed, and where future recovery through rates is probable, the present value of the liability is subsequently deferred as a regulatory asset.

AROs are computed as the present value of the estimated costs associated with the future retirement of an asset and are recorded in the period in which the liability is incurred. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be decommissioned and the liabilities will be remediated as well as the inflation rate and discount rate, which may change significantly over time. The estimated costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Registrants have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since the Registrants plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrants abandon or cease the use of specific easements, which is not expected.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances to/from Affiliates, Accounts Receivable, Accounts Payable and Short-term Debt approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities (Applies to all Registrants except AEPTCo)

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

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

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan and 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 benefits and 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. Investments classified as Other are valued using Net Asset Value as a practical expedient. Items classified as Other are primarily cash equivalent funds, common collective trusts, commingled funds, structured products, private equity, real estate and infrastructure investments. These investments do not have a readily determinable fair value or they contain redemption restrictions which may include the right to suspend redemptions under certain circumstances. Redemption restrictions may also prevent certain investments from being redeemed at the reporting date for the underlying value.

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

The cost of purchased electricity, fuel and related emission allowances and emission control chemicals/consumables is charged to Purchased Electricity, Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily using the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is an expectation that refunds or recoveries will extend beyond a one year period, based on a company's filing with a commission or a commission directive. These deferrals are incorporated into the development of future fuel rates billed to or refunded to customers. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit the Registrants' fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. The Registrants share the majority of their Off-system Sales margins to customers either through an active FAC or other rate mechanisms. Where the FAC or Off-system Sales sharing mechanism is capped, frozen, non-existent or applicable to merchant operations, changes in fuel costs or sharing of Off-system Sales impact earnings.

Revenue Recognition

Regulatory Accounting

The Registrants' financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses or alternative revenues recognized in accordance with the guidance for "Regulated Operations") and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching revenue with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, assets are recorded on the balance sheets. Regulatory assets are reviewed for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, the regulatory asset is derecognized as a charge against income.

Retail and Wholesale Supply and Delivery of Electricity

The Registrants recognize revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. The Registrants recognize such revenues on the statements of income as the performance obligations of delivering energy to customers are satisfied. Recognized revenues include both billed and unbilled amounts. In accordance with the applicable state commission's regulatory treatment, PSO and SWEPCo do not include the fuel portion in unbilled revenue, but rather recognize such revenues when billed to customers.

Wholesale transmission revenue is based on FERC-approved formula rate filings made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under-recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. These annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations". An estimated annual true-up is recorded by the Registrants in the fourth quarter of each calendar year and a final annual true-up is recognized by the Registrants in the second quarter of each calendar year following the filing of annual FERC reports. Any portion of the true-ups applicable to an affiliated company is recorded as Accounts Receivable - Affiliated Companies or Accounts Payable - Affiliated Companies on the balance sheets. Any portion of the true-ups applicable to third-parties is recorded as Regulatory Assets or Regulatory Liabilities on the balance sheets. See Note 20 - Revenue from Contracts with Customers for additional information.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

Most of the power produced at the generation plants is sold to PJM or SPP. The Registrants also purchase power from PJM and SPP to supply power to customers. Generally, these power sales and purchases are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to PJM or SPP, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity on the statements of income. With the exception of certain dedicated load bilateral power supply contracts, the transactions of AEP's nonregulated subsidiaries are reported as gross purchases or sales.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's 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. Realized gains and losses on cash flow hedges are recorded in Total Revenues or Purchased Electricity depending on the nature of the risk being hedged. Derivative purchases elected normal used to serve accrual based obligations are recorded in Purchased Electricity on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, the Registrants record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities (Applies to all Registrants except AEPTCo)

The Registrants engage in power, capacity, and to a lesser extent, natural gas marketing as major power producers and participants in electricity and natural gas markets. The Registrants also engage in power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity risk management activities focused on markets where the AEP System owns assets and on adjacent markets. These activities include the purchase-and-sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

The Registrants recognize revenues from marketing and risk management transactions that are not derivatives as the performance obligation of delivering the commodity is satisfied. Expenses from marketing and risk management transactions that are not derivatives are also recognized upon delivery of the commodity.

The Registrants use MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities, as appropriate, and on the statements of income in Total Revenues. Realized gains and losses on marketing and risk management transactions are included in revenues or expenses based on the transaction's facts and circumstances. However, in regulated jurisdictions subject to cost-based regulation, unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Certain qualifying marketing and risk management derivatives transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). In the event the Registrants designate a cash flow hedge, the cash flow hedge's gain or loss is initially recorded as a component of AOCI. When the forecasted transaction is realized and affects net income, the Registrants subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on their statements of income. See "Accounting for Cash Flow Hedging Strategies" section of Note 10 for additional information.

Levelization of Nuclear Refueling Outage Costs (Applies to AEP and I&M)

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over approximately 18 months, beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins.

Maintenance

The Registrants expense maintenance costs as incurred. If it becomes probable that the Registrants will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. In certain regulated jurisdictions, the Registrants defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment and Production Tax Credits

The Registrants use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

When the flow-through method of accounting for temporary differences is required by a regulator to be reflected in regulated revenues (that is, when deferred taxes are not included in the cost-of-service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

AEP and subsidiaries apply the deferral methodology for the recognition of ITCs. Deferred ITCs are amortized to income tax expense over the life of the asset that generated the credit. Amortization of deferred ITCs begins when the asset is placed in-service, except where regulatory commissions reflect ITCs in the ratemaking process, then amortization begins when the utility is able to utilize the ITC on a stand-alone basis. Alternatively, PTCs reduce income tax expense as they are earned. PTCs are earned when electricity is produced. Absent IRS guidance on the calculation of "gross receipts", the Nuclear PTC recognized is based on electricity produced and an estimate of gross receipts. If, and when, IRS guidance is issued, the value of the Nuclear PTC will be updated to reflect such guidance, if necessary.

Transferable tax credits established by the IRA are accounted for in accordance with the accounting guidance for "Income Taxes" by the Registrants. Proceeds from sales of transferable tax credits are included as a component of Operating Activities on the statement of cash flows and presented as net within the Income Taxes Footnote.

The Registrants account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." The Registrants classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation expense on the statements of income.

AEP and subsidiaries join in the filing of a consolidated federal income tax return. The benefit of current tax loss of the parent company (Parent Company Loss Benefit) to the AEP System subsidiaries is accounted for as an allocation through equity. The consolidated NOL of the AEP System is allocated to each company in the consolidated group with taxable loss. With the exception of the allocation of the consolidated AEP System NOL, Parent Company Loss Benefit and general business tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

Excise Taxes (Applies to all Registrants except AEPTCo)

As agents for some state and local governments, the Registrants collect from customers certain excise taxes levied by those state or local governments on customers. The Registrants do not record these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility assets are deferred and amortized over the remaining term of the reacquired debt in accordance with their ratemaking treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Operations not subject to cost-based rate regulation report gains and losses on the reacquisition of debt in Interest Expense on the statements of income upon reacquisition.

Debt discounts, premiums and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The net amortization expense is included in Interest Expense on the statements of income.

Pension and OPEB Plans (Applies 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. The Registrant Subsidiaries account for their participation in the AEPSC sponsored pension and OPEB plans using multiple-employer accounting. See Note 8 - Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities (Applies to all Registrants except AEPTCo)

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and SNF disposal. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	35 %
Fixed Income	49 %
Other Investments	15 %
Cash and Cash Equivalents	1 %
OPEB Plans Assets	**Target**
Equity	63 %
Fixed Income	36 %
Cash and Cash Equivalents	1 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies or certain commingled funds). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law.

For equity investments, the concentration limits are generally as follows:

- No security in excess of 5% of the outstanding class of equity of any one company.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, each investment manager's portfolio is compared to investment grade, diversified benchmark indices.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to diversify holdings by region, property type and risk classification. Real estate holdings include core, value-added and opportunistic classifications.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships to invest across the private equity investment spectrum. The private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investments.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2025 and 2024, the fair value of securities on loan as part of the program was $139 million and $60 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2025 and 2024.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities.

Nuclear Trust Funds (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. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Stock-Based Compensation Plans

As of December 31, 2025, AEP had performance shares and restricted stock units outstanding under the American Electric Power System 2024 Long-Term Incentive Plan (2024 LTIP) and the American Electric Power System 2015 Long-Term Incentive Plan (2015 LTIP). Upon vesting, all outstanding performance shares and restricted stock units settle in AEP common stock. The impact of AEP's stock-based compensation plan is insignificant to the financial statements of the Registrant Subsidiaries.

AEP maintains a variety of tax-qualified and non-qualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes AEP career shares maintained under the American Electric Power System Stock Ownership Requirement Plan (SORP), which facilitates executives in meeting minimum stock ownership requirements assigned to them by the Human Resources Committee of the Board of Directors. AEP career shares are derived from vested performance shares granted to employees under a long-term incentive plan. AEP career shares accrue additional dividend shares in an amount equal to dividends paid on AEP common shares at the closing market price on the dividend payments date. All AEP career shares are settled in shares of AEP common stock after the executive's service with AEP ends.

Performance shares are classified as temporary equity on the balance sheets until the awards vest. Upon vesting, the performance shares are classified as permanent equity. These awards may be settled in cash upon an employee's qualifying termination due to a change in control. Because such event is not solely within the control of the company, these awards are classified outside of permanent equity until the awards vest.

AEP compensates non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors.

Management measures and recognizes compensation expense for all share-based payment awards to employees and directors based on estimated fair values. For awards that are paid in shares with service only vesting conditions, management recognizes compensation expense on a straight-line basis over the vesting period. Stock-based compensation expense recognized on the statements of income for the years ended December 31, 2025, 2024 and 2023 is based on the number of outstanding awards at the end of each period without a reduction for estimated forfeitures. AEP accounts for forfeitures in the period in which they occur.

For the years ended December 31, 2025, 2024 and 2023, compensation costs are included in Net Income for performance shares, career shares, restricted stock units, unrestricted shares, non-employee director stock units and other qualified and non-qualified deferred compensation plans that provide an investment in or an investment return equivalent to that of AEP common stock. Compensation costs may also be capitalized. See Note 16 - Stock-based Compensation for additional information.

Noncontrolling Interests (Applies to AEP, AEPTCo and SWEPCo)

Noncontrolling interests represent the portion of equity in certain consolidated subsidiaries that is not attributable to the Registrants. For these subsidiaries, the Registrants hold a controlling financial interest, but not all the outstanding equity. The noncontrolling owners' share of the subsidiaries' net assets is presented as Noncontrolling Interests within Total Equity on the balance sheets. The portion of net income and other comprehensive income attributable to noncontrolling interests is presented separately in the statements of income and statements of comprehensive income. Distributions to noncontrolling interest holders are recorded as reductions to the noncontrolling interest balance. Contributions from noncontrolling interest holders are recorded as additions to the noncontrolling interest balance. Changes in the Registrant's ownership interest in a subsidiary that do not result in a loss of control are accounted for as equity transactions. Any difference between the consideration transferred and the adjustment to the noncontrolling interest is recognized directly in Paid-in Capital.

Equity Method Investments in Unconsolidated Entities (Applies to AEP and SWEPCo)

The equity method of accounting is used for equity investments where either AEP or SWEPCo exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. The proportionate share of the investee's equity earnings or losses is included in Equity Earnings (Loss) of Unconsolidated Subsidiaries on the statements of income. AEP and SWEPCo regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recognized when the investment has experienced a loss in value that is other-than-temporary in nature.

As of December 31, 2025, AEP's equity method investments include ETT, DHLC and Gigawatt AI. See Note 18 - Variable Interest Entities and Equity Method Investments for additional information.

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 15 - 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:

	Years Ended December 31,					
	2025		**2024**		**2023**	
	(in millions, except per-share data)					
		$/share		**$/share**		**$/share**
Earnings Attributable to AEP Common Shareholders	$ 3,580		$ 2,967		$ 2,208	
Weighted-Average Number of Basic AEP Common Shares Outstanding	534.5	$ 6.70	530.1	$ 5.60	518.9	$ 4.26
Weighted-Average Dilutive Effect	3.0	(0.04)	1.2	(0.02)	1.3	(0.02)
Weighted-Average Number of Diluted AEP Common Shares Outstanding	537.5	$ 6.66	531.3	$ 5.58	520.2	$ 4.24

There were no antidilutive shares outstanding as of December 31, 2025, 2024 and 2023.

Supplementary Income Statement Information

The following tables provide the components of Depreciation and Amortization for the years ended December 31, 2025, 2024 and 2023:

2025

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 3,325	$ 420	$ 478	$ 652	$ 471	$ 380	$ 293	$ 391
Amortization of Certain Securitized Assets	46	18	—	—	—	—	—	20
Amortization of Regulatory Assets and Liabilities	9	3	—	(20)	43	—	(33)	18
Total Depreciation and Amortization	$ 3,380	$ 441	$ 478	$ 632	$ 514	$ 380	$ 260	$ 429

2024

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 3,149	$ 406	$ 431	$ 600	$ 456	$ 386	$ 263	$ 375
Amortization of Certain Securitized Assets	91	91	—	—	—	—	—	—
Amortization of Regulatory Assets and Liabilities	50	(3)	—	2	25	—	9	14
Total Depreciation and Amortization	$ 3,290	$ 494	$ 431	$ 602	$ 481	$ 386	$ 272	$ 389

2023

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 2,927	$ 380	$ 394	$ 571	$ 440	$ 316	$ 241	$ 323
Amortization of Certain Securitized Assets	92	92	—	—	—	—	—	—
Amortization of Regulatory Assets and Liabilities	71	(3)	—	1	30	—	15	20
Total Depreciation and Amortization	$ 3,090	$ 469	$ 394	$ 572	$ 470	$ 316	$ 256	$ 343

Supplementary Cash Flow Information (Applies to AEP)

	Years Ended December 31,		
Cash Flow Information	**2025**	**2024**	**2023**
		(in millions)	
Cash Paid for:			
Interest, Net of Capitalized Amounts	$ 1,894	$ 1,838	$ 1,674
Noncash Investing and Financing Activities:			
Acquisitions Under Finance Leases	44	30	49
Construction Expenditures Included in Current Liabilities as of December 31,	1,935	1,312	842
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	10	24	24
Noncash Increase in Noncurrent Assets from the Sale of the Competitive Contracted Renewables Portfolio	—	—	75

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.

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

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

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

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

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

Management adopted ASU 2023-09 and its related implementation guidance effective January 1, 2025 for the annual reporting period and applied the amendments retrospectively to all prior periods presented in the annual consolidated financial statements. The adoption of the new standard did not impact the results of operations, statements of financial position or cash flows. See Note 12 - Income Taxes for additional information.

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 is not expected to have a material impact on the results of operations, statements of financial position or cash flows.

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 for the years ended December 31, 2025, 2024 and 2023. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 - Benefit Plans for additional information.

	Cash Flow Hedges		Pension and OPEB		
For the Year Ended December 31, 2025	**Commodity**	**Interest Rate**	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
			(in millions)		
Balance in AOCI as of December 31, 2024	$ 99	$ 3	$ 99	$ (204)	$ (3)
Change in Fair Value Recognized in AOCI, Net of Tax	(9)	(1)	—	63	53
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	(15)	—	—	—	(15)
Interest Expense (a)	—	(4)	—	—	(4)
Amortization of Prior Service Cost (Credit)	—	—	(1)	—	(1)
Amortization of Actuarial (Gains) Losses	—	—	2	—	2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(15)	(4)	1	—	(18)
Income Tax (Expense) Benefit	(3)	(1)	—	—	(4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(12)	(3)	1	—	(14)
Net Current Period Other Comprehensive Income (Loss)	(21)	(4)	1	63	39
Balance in AOCI as of December 31, 2025	$ 78	$ (1)	$ 100	$ (141)	$ 36

	Cash Flow Hedges		Pension and OPEB		
For the Year Ended December 31, 2024	**Commodity**	**Interest Rate**	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
			(in millions)		
Balance in AOCI as of December 31, 2023	$ 105	$ (8)	$ 93	$ (245)	$ (55)
Change in Fair Value Recognized in AOCI, Net of Tax	3	6	—	41	50
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	(11)	—	—	—	(11)
Interest Expense (a)	—	6	—	—	6
Amortization of Prior Service Cost (Credit)	—	—	(5)	—	(5)
Amortization of Actuarial (Gains) Losses	—	—	1	—	1
Recognition of Pension Settlement Costs	—	—	11	—	11
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(11)	6	7	—	2
Income Tax (Expense) Benefit	(2)	1	1	—	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(9)	5	6	—	2
Net Current Period Other Comprehensive Income (Loss)	(6)	11	6	41	52
Balance in AOCI as of December 31, 2024	$ 99	$ 3	$ 99	$ (204)	$ (3)

For the Year Ended December 31, 2023	Cash Flow Hedges: Commodity	Cash Flow Hedges: Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2022	$ 224	$ —	$ 106	$ (246)	$ 84
Change in Fair Value Recognized in AOCI, Net of Tax	(176)	(6)	—	(16)	(198)
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	72	—	—	—	72
Interest Expense (a)	—	(3)	—	—	(3)
Amortization of Prior Service Cost (Credit)	—	—	(21)	—	(21)
Amortization of Actuarial (Gains) Losses	—	—	5	—	5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	72	(3)	(16)	—	53
Income Tax (Expense) Benefit	15	(1)	(3)	—	11
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	57	(2)	(13)	—	42
Reclassifications of KPCo Pension and OPEB Regulatory Assets to AOCI, before Income Tax (Expense) Benefit	—	—	—	21	21
Income Tax (Expense) Benefit	—	—	—	4	4
Reclassifications of KPCo Pension and OPEB Regulatory Assets to AOCI, Net of Income Tax (Expense) Benefit	—	—	—	17	17
Net Current Period Other Comprehensive Income (Loss)	(119)	(8)	(13)	1	(139)
Balance in AOCI as of December 31, 2023	$ 105	$ (8)	$ 93	$ (245)	$ (55)

(a) Amounts reclassified to the referenced line item on the statements of income.

4. <u>RATE MATTERS</u>

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

The Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. The Registrants' recent significant rate orders and pending rate filings are addressed in this note.

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

AEP Texas Interim Transmission and Distribution Rates

Through December 31, 2025, AEP Texas' cumulative revenues from transmission and distribution interim base rate increases that are subject to review are estimated to be approximately $118 million. A base rate review could result in a refund to customers if AEP Texas incurs a disallowance of the transmission or distribution investment on which an interim increase was based. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission and distribution rates, could reduce future net income and cash flows and impact financial condition.

Texas Legislation

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

The UTM permits a qualifying electric utility to defer all or a portion of costs associated with its eligible transmission and distribution capital investments, including depreciation expense and carrying costs, as a regulatory asset. The tracking mechanism is available through 2035 and is an alternative to the existing capital tracking mechanisms in Texas. As a result of the new legislation, AEP Texas deferred approximately $56 million of eligible costs through December 2025 as a regulatory asset.

2025 UTM Filing

In October 2025, AEP Texas submitted its first filing with the PUCT seeking recovery of eligible costs through the UTM established by HB 5247. This filing combined three recovery mechanisms (Interim Transmission Cost of Service and Distribution Cost Recovery Factor capital trackers and the Transmission Cost Recovery Factor) into a single filing. The capital tracker incremental revenue requirement, inclusive of the items outlined in the January 2026 brief, sought in this filing is $100 million, including a request to recover, over a 12-month period, $38 million of eligible costs related to UTM deferrals and $2 million of eligible costs related to the System Resiliency Plan deferrals, both inclusive of equity carrying charges through the July 2025 test year period end. In November 2025, an intervenor proposed a $31 million reduction to the UTM deferral balance. The filing is currently undergoing a paper hearing and in January 2026 the parties filed briefs reiterating their position. A resolution is expected in the first half of 2026. Investments included in the UTM and the existing capital tracker filings remain subject to prudency review in the utility's next base rate review before the PUCT. If any of these deferred costs are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

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

ENEC (Expanded Net Energy Cost) Filings

In January 2024, the WVPSC issued an order resolving APCo's and WPCo's (the Companies) 2021-2023 ENEC cases. In the order, the WVPSC: (a) disallowed $232 million in ENEC under-recovered costs as of February 28, 2023 ($136 million related to APCo) and (b) approved the recovery of $321 million of ENEC under-recovered costs as of February 28, 2023 ($174 million related to APCo) plus a 4% debt carrying charge rate over a ten-year recovery period starting September 1, 2024.

In February 2024, the Companies filed briefs with the West Virginia Supreme Court (WVSC) to initiate an appeal of the January 2024 order. Following arguments that were held in September 2024, the WVSC issued a November 2024 opinion affirming in part and reversing in part the WVPSC's January 2024 ENEC order. The WVSC remanded the ENEC case to the WVPSC to afford the Companies an opportunity to examine, analyze, rebut and refute the calculation of the $232 million disallowance.

In March 2025, the WVPSC entered an order in the Companies' 2021-2023 ENEC 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.

In April 2024, the Companies submitted their 2024 ENEC update case proposing a $58 million annual increase in ENEC rates when compared to existing ENEC rates. The Companies proposed that this ENEC rate change would: (a) become effective September 1, 2024, (b) include a $20 million annual increase in ENEC rates related to the period ending February 29, 2024 and the forecast period September 2024 through August 2025 and (c) include a $38 million annual increase in ENEC rates for the recovery of $321 million of ENEC under-recovered costs as of February 28, 2023, over a ten-year period, plus a 4% debt carrying charge rate. In August 2024, the WVPSC issued an order approving the requested $38 million annual increase effective September 1, 2024. In March 2025, the WVPSC issued an order approving the requested $20 million annual increase effective March 11, 2025.

In April 2025, the Companies submitted their 2025 ENEC update filing proposing a $72 million annual increase in ENEC rates. In September 2025, the WVPSC issued an order on the Companies' 2025 ENEC update filing approving an annual ENEC revenue requirement increase of $70 million with no change in ENEC rates charged to customers. The WVPSC ordered this ENEC customer rate increase to occur upon securitization which is expected in the first half of 2026 as further described in the "2025 West Virginia Securitization Filing" section below. The WVPSC denied an intervenor-recommended ENEC under-recovery disallowance of $19 million.

Virginia Fuel Adjustment Clause (FAC) Review

In 2023, APCo submitted its annual fuel cost filing with the Virginia SCC. Interim Virginia FAC rates were implemented in November 2023. In APCo's 2022 Virginia fuel update filing, the Virginia SCC ordered the Virginia Staff to commence an audit of APCo's fuel costs for the years ended December 31, 2019, 2020, 2021 and 2022. The Virginia Staff analyzed APCo's 2019 through 2022 fuel procurement activities and concluded the procurement practices were reasonable and prudent and recommended no disallowances. In May 2024, the Virginia SCC issued an order approving the audit of APCo's 2019 and 2020 fuel costs but concluded that the review of APCo fuel costs for 2021 and 2022 should remain open for further evaluation as part of APCo's 2024 fuel cost filing.

In September 2024, APCo submitted its annual Virginia fuel cost filing with the Virginia SCC proposing no change in annual APCo Virginia FAC rates charged to customers for the period November 2024 through October 2025. In January 2025, an intervening party recommended a minimum fuel under-recovery disallowance of $20 million related to alleged imprudent operations of Amos and Mountaineer generating units during October 2021 and November 2021. There were no other recommended disallowances by intervenors or Virginia Staff regarding APCo's historical period Virginia fuel under-recovery balance through October 31, 2024. Virginia Staff also recommended that the Virginia SCC close APCo's open review periods related to 2021 and 2022 Virginia fuel costs with no cost disallowances. A hearing was held in May 2025. In June 2025, the Hearing Examiner issued a report recommending that the Virginia SCC order: (a) no change in annual APCo Virginia FAC rates for the period November 2024 through October 2025, (b) no cost disallowances for APCo's Virginia FAC review period ending October 31, 2024 and (c) no cost disallowances for APCo's 2021 and 2022 Virginia fuel cost review periods. In December 2025, the Virginia SCC issued an order approving the recommendations of the Hearing Examiner.

2024 West Virginia Base Rate Case

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

The Companies' November 2024 West Virginia base rate filing also included two sets of alternative frameworks to simplify rates and customer bills and provide predictable future rate increases. The Companies' first framework includes: (a) securitization, (b) approval of a major storm expense recovery and tracking mechanism and (c) freezing of OATT revenues in the ENEC. This framework includes securitization in a concurrent proceeding of approximately $2.4 billion of West Virginia jurisdictional assets. Securitization of those items could reduce the Companies' combined requested increase in annual base rates to $37 million. See the "2025 West Virginia Securitization Filing" section below for additional information.

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

In August 2025, the WVPSC issued an order on the Companies' base case filing. The WVPSC's order: (a) approved a combined annual base rate revenue requirement increase of $76 million ($67 million related to APCo) based on a 9.25% ROE and a capital structure of 56% debt and 44% equity, (b) included recovery of $24 million of previously deferred storm costs with no carrying charges, with future securitization of these deferred storm costs as described in the "2025 West Virginia Securitization Filing" section below, (c) included a decrease in the base rate revenue requirement related to a WVPSC-ordered decrease in depreciation rates, (d) required the Companies to recover the monthly level of this base rate increase through current ENEC rates, (e) effectively terminated the Companies' MRBC, Mitchell Base Rate and Vegetation Management surcharges upon the approved change in base rates revenue requirement with these surcharges rolled into base rates, (f) stipulated that the Companies' proposals related to the inclusion of a stand-alone NOLC deferred tax asset in rate base will be addressed in a future proceeding upon the Companies' receipt of a PLR from the IRS and (g) approved the Companies' requested West Virginia jurisdictional environmental and new generation surcharge but did not approve the Companies' proposed storm tracking mechanism, annual 3% surcharge increase and freezing of OATT revenues in the ENEC. In September 2025, the Companies filed a petition for reconsideration with the WVPSC to explain the financial consequences of the order and seek clarification on certain issues.

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 as these issues will be addressed in a future filing. The WVPSC's August 2025 base case order stipulated that the Companies' proposals related to the inclusion of a stand-alone NOLC deferred tax asset in rate base will be addressed in a future proceeding upon the Companies' receipt of a PLR from the IRS.

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

2025 West Virginia Securitization Filing

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

In August 2025, the WVPSC issued an interim order stating that it will approve the Companies' future securitization of the generation plant assets, ENEC under-recovery balances, environmental costs and deferred storm operation and maintenance costs.

In September 2025, and as directed by the WVPSC in the August 2025 interim order described above, the Companies submitted an updated proposed financing order that reflected additional ENEC under-recovery balances for costs incurred in 2025 and additional storm operation and maintenance deferral balances for the impacts of Hurricane Helene and winter storms Blair, Harlow and Jett. WPCo forecasted CCR and ELG amounts below related to the Mitchell Plant are subject to change based on the fourth quarter 2025 KPSC order approving the settlement agreement on KPCo's June 2025 CPCN filing that 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. 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. All amounts in the table below are subject to further review in a future final securitization financing order that the Companies expect will be issued by the WVPSC in 2026. See the summarization of the proposed securitization items in the table below:

Proposed Securitized Items	APCo	WPCo	Total
		(in millions)	
Undepreciated Utility Plant Balances of Amos, Mitchell and Mountaineer (as of December 31, 2022)	$ 1,145	$ 559	$ 1,704
ENEC Under-Recovery Regulatory Assets	167	246	413
Forecasted Undepreciated CCR and ELG Investments of Amos, Mitchell and Mountaineer (as of November 30, 2024)	88	149	237
Deferred Storm Other Operation and Maintenance Expense Regulatory Assets	155	3	158
Upfront Financing Costs	10	6	16
Total	$ 1,565	$ 963	$ 2,528

Upon receipt of the final financing order, the Companies expect to proceed with the securitization bonds issuance process and to complete the securitization in the first half 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 July 2025, APCo filed a request with the Virginia SCC to finance, through the issuance of proposed 20-year securitization bonds, approximately $1.4 billion of Virginia jurisdictional undepreciated property balances and a major storm operation and maintenance regulatory asset deferral balance. This proposed securitization included: (a) $1.2 billion of undepreciated Virginia jurisdictional plant balances as of December 31, 2023 for the Amos and Mountaineer Plants and (b) $141 million of Virginia jurisdictional major storm other operation and maintenance expenses deferred during the 2024-2025 biennial period. In September 2025, Virginia SCC staff submitted testimony concluding that all costs proposed by APCo for securitization are eligible for securitization in accordance with Virginia law. While also concluding that APCo's proposed securitization of the Amos and Mountaineer Plants over 20 years offers benefits to customers through rate relief, Virginia SCC staff took no position on APCo's proposed securitization of major storm other operation and maintenance expenses due to the apparent lack of significant benefit or cost savings for customers. In October 2025, the Hearing Examiner recommended the Virginia SCC approve the requested $1.4 billion for securitization. In November 2025, the Virginia SCC issued a financing order approving securitization of the requested $1.4 billion of Virginia jurisdictional costs. In accordance with Virginia statutory requirements and the financing order, the issuance of the securitization bonds is subject to final review by the Virginia SCC after bond pricing. APCo expects to proceed with the securitization bond issuance process and to complete the securitization process in the first half 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.

ETT Rate Matters (Applies to AEP)

2025 ETT Base Rate Case

In January 2025, ETT filed a request with the PUCT for a $57 million annual base rate increase over its adjusted test year revenues which includes interim transmission rate updates. ETT's request was based upon a proposed 10.6% ROE with a capital structure of 55% debt and 45% common equity. The rate case sought a prudence review determination on cumulative capital additions included in interim rates. In April and May 2025, respectively, intervenors and PUCT staff submitted testimony challenging components of the proposed rate increase including up to $37 million related to increased depreciation rates and $32 million related to the proposed ROE and capital structure.

In June 2025, a unanimous and unopposed settlement was filed with the PUCT along with a motion to approve interim rates, equal to the rates specified in the settlement, effective on June 20, 2025. The settlement terms included a base rate increase of approximately $20 million, based on an ROE of 9.6% and a capital structure of 59% debt and 41% equity. The settlement also included a determination that ETT's invested capital and rate base are prudent and properly included in rates. The motion to approve interim rates was granted in June 2025. In October 2025, the PUCT issued an order approving the June 2025 settlement. The rates approved by the order are identical to the rates approved on an interim basis.

I&M Rate Matters (Applies to AEP and I&M)

Michigan Power Supply Cost Recovery (PSCR) Reconciliation

2023 PSCR Reconciliation

In March 2024, I&M submitted its 2023 PSCR Reconciliation to the MPSC. In October 2024, MPSC staff and intervenors submitted testimony recommending PSCR cost disallowances associated with the OVEC Inter-Company Power Agreement (ICPA) and the Rockport UPA with AEGCo ranging from $3 million to $15 million. In July 2025, the MPSC issued an order resulting in a combined $3 million PSCR cost disallowance related to OVEC and Rockport UPA costs. In July 2025, the IURC issued an order on I&M's Resource Adequacy Rider update filing approving I&M's proposed capacity resource adjustments, including prospective recovery of OVEC capacity, energy and associated costs that were previously assigned to I&M Michigan retail customers starting with the June 2025-May 2026 PJM delivery year.

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 ICPA and the Rockport UPA with AEGCo ranging from $259 thousand to $14 million. A hearing on I&M's 2024 PSCR Reconciliation was held in December 2025 and an MPSC order is expected in the second quarter of 2026. Any future disallowances ordered by the MPSC on I&M's 2024 PSCR Reconciliation could reduce future net income and cash flows and impact financial condition.

Indiana Earnings Test

I&M is required by Indiana law to submit an earnings test evaluation for the most recent one-year and five-year periods as part of I&M's semi-annual Indiana FAC filings. These earnings test evaluations require I&M to include a credit in the FAC factor computation for periods in which I&M earned above its authorized return for both the one-year and five-year periods. The credit is determined as 50% of the lower of the one-year or five-year earnings above the authorized level. Management believes its financial statements adequately address the impact of Indiana earnings test requirements previously established by the IURC. 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 January 2025, I&M submitted its FAC filing and earnings test evaluation for the period ended November 2024. I&M proposed an over-earnings credit to customers for the earnings test period ending November 2024 of $21 million. In April 2025, the IURC issued an order approving the $21 million customer credit.

In July 2025, I&M submitted its FAC filing and earnings test evaluation for the period ended May 2025. I&M proposed an over-earnings credit to customers for the earnings test period ending May 2025 of $35 million. In October 2025, the IURC issued an order approving the $35 million customer credit.

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. An IURC order approving I&M's proposed jurisdictional cost allocation modifications and as-filed over-earnings credit would increase future net income and cash flows and impact financial condition.

KPCo Rate Matters (Applies to AEP)

Investigation of the Service, Rates and Facilities of KPCo

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

2023 Kentucky Base Rate and Securitization Case

In June 2023, KPCo filed a request with the KPSC for a $94 million net annual increase in base rates based upon a proposed 9.9% ROE with the increase to be implemented no earlier than January 2024. In conjunction with its June 2023 filing, KPCo further requested to finance through the issuance of securitization bonds, approximately $471 million of regulatory assets. KPCo's proposal did not address the disposition of its 50% interest in Mitchell Plant, which will be addressed in the future. See "Mitchell Plant Filing for Certificate of Public Convenience and Necessity" section below for additional information.

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

In January 2024, the KPSC issued an order modifying the November 2023 uncontested settlement agreement and approving an annual base rate increase of $60 million based upon a 9.75% ROE effective with billing cycles starting mid-January 2024. The order reduced KPCo's base rate revenue requirement by $14 million to allow recovery of actual test year PJM transmission costs instead of KPCo's requested annual level of costs based on PJM 2023 projected transmission revenue requirements. In February 2024, KPCo filed an appeal with the Commonwealth of Kentucky Franklin Circuit Court (Circuit Court), challenging among other aspects of the order, the $14 million base rate revenue requirement reduction. In January 2025, the Circuit Court issued an order agreeing with KPCo's appeal and remanded this issue back to the KPSC with instructions to enter an order, within 30 days, which includes setting rates to allow KPCo to recover the $14 million of annual PJM transmission costs effective upon KPCo's January 2024 implementation of updated base rates. In March 2025, the KPSC issued a rehearing order that approved rates for the prospective collection of test year PJM transmission costs beginning in February 2025 but denied KPCo's request to defer and recover the historical PJM transmission costs of approximately $16 million incurred from January 2024 through the February 2025 update in base rates. In April 2025, KPCo filed an appeal with the Circuit Court for a motion to enforce in response to the KPSC's denial to recover PJM transmission costs incurred from January 2024 through the implementation of new rates. In September 2025, the Circuit Court issued an order granting KPCo's motion to enforce. In October 2025, the KPSC issued an order approving recovery of the $16 million of PJM transmission costs, with debt and equity carrying charges starting September 15, 2025 on the remaining PJM transmission costs to be recovered, through a rider. The rider was effective with the first billing cycle in November 2025 and will be in place for 22 months.

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

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 December 31, 2025, 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 $523 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, an intervenor filed a brief recommending that the KPSC should deny the requested rate increase. The intervenor also stated that if the KPSC were to approve a rate increase, the settlement agreement should be modified to a $40 million annual increase in KPCo base rates based on an 8.9% ROE and a capital structure of 55% debt and 45% common equity. Additionally, the brief: (a) suggests increasing the amount of the first and second year revenue requirement reductions to $49 million and $28 million, respectively, relating to the new rider proposed in the settlement agreement that returns certain unprotected deferred tax expenses in customer rates on a temporary basis, (b) proposes that KPCo should be restricted from filing to recover Mitchell Plant non-ELG capital costs, expected to result from the approved settlement agreement in the 2025 Mitchell Plant CPCN proceeding, for a minimum of three years (see "Mitchell Plant Filing for Certificate of Public Convenience and Necessity" section above for additional information) and (c) recommends that the KPSC order an independent management audit to engage outside experts to determine how KPCo can improve its service and rates.

A KPSC order is expected to be issued in the first quarter of 2026 with implementation of KPCo retail rates in March 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.

<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. Oral arguments were conducted in December 2025 and the appeals are now fully submitted for decision.

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.

Ohio Legislation (HB 15)

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

As a result of this legislation, OPCo recorded a $24 million reduction in 2025 to its OVEC-related purchased power regulatory asset for deferred net costs that are no longer probable of future recovery. Management is unable to predict the future impact to net income, cash flows and financial condition arising from the future changes in OPCo's rate setting mechanisms and the elimination of OPCo's ability to recover from, or refund to, customers the difference between purchased power expenses from OVEC and the market revenues OPCo receives from that purchased power. See "OVEC" section of Note 18 for additional information.

2025 Ohio Base Rate Case

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

In October 2025, the PUCO staff filed its required report recommending a net annual decrease in distribution base rates ranging from $12 million to $28 million, based upon an ROE range of 9.33% to 9.84%. The PUCO staff recommended the exclusion of $59 million of certain utility investments and $55 million of capitalized incentives from rate base, and a reduction in employee-related expenses of $23 million. In addition, the PUCO staff recommended increases to the DIR revenue cap and ESRR cost cap that were less than OPCo's requested increases. Responses to the PUCO staff report were submitted in November 2025 and a hearing was held in January 2026.

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 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 and the resolution of various rate base and operating income issues raised in the PUCO staff report. Additionally, the agreement proposes increased revenue caps for the DIR, annual cost cap increases in the ESRR and would result in no material disallowances.

If the settlement agreement is approved by the PUCO, new base rates will go into effect 14 days after such approval. If any costs included in this filing are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

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

2024 Oklahoma Base Rate Case

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

In October 2024, PSO, the OCC and certain intervenors filed a joint stipulation and settlement agreement with the OCC that included a net annual revenue increase of $120 million based upon a 9.5% ROE with a capital structure of 48.9% debt and 51.1% common equity. The agreement also allows for Rock Falls Wind Facility to be included in base rates and the deferral of certain generation-related costs necessary to comply with SPP's 2023 increased capacity reserve margin requirements. One intervenor opposed the joint stipulation and settlement agreement. In October 2024, a hearing was held at the OCC, and PSO implemented an interim annual base rate increase of $120 million, subject to refund pending a final order by the OCC.

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

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. 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)

2020 Texas Base Rate Case

In October 2020, SWEPCo filed a request with the PUCT for a $105 million annual increase in Texas base rates based upon a proposed 10.35% ROE. The request would move transmission and distribution interim revenues recovered through riders into base rates. Eliminating these riders would result in a net annual requested base rate increase of $90 million primarily due to increased investments. SWEPCo subsequently filed a request with the PUCT lowering the requested annual increase in Texas base rates to $100 million which would result in an $85 million net annual base rate increase after moving the proposed riders to rate base.

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

2025 Arkansas Base Rate Case

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

In November 2025, an uncontested settlement agreement was filed with the APSC for an $85 million annual base rate increase based upon a 9.65% ROE with a capital structure of 55.7% debt and 44.3% common equity. The settlement agreement allowed SWEPCo to recover the Arkansas jurisdictional share of the remaining net book value of the Pirkey Plant over 10 years and earn a return of 3%, and the agreement also included a provision that the retirement of the Pirkey Plant was prudent. In January 2026, the APSC issued an order approving the settlement agreement as filed.

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. Intervenor and staff testimony is due in March 2026 and a hearing is scheduled for April 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.

<u>PSO and SWEPCo Rate Matters</u> (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.

<u>FERC Rate Matters</u>

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. In October 2025, the Maryland Public Service Commission approved an extension of the construction commencement deadline to May 2026. Additional regulatory proceedings before the PAPUC are expected to resume in 2026.

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 December 31, 2025, AEP's share of IEC capital expenditures was approximately $92 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 are providing refunds for the 2021 rate year, primarily through 2025 projected transmission revenue requirements. AEP transmission owning subsidiaries within PJM and SPP have not been directed to make cash refunds related to 2022 through 2025 rate years. As a result of the January 2024 FERC orders, the Registrants' balance sheets reflected a liability for the probable refund of all NOLC revenues included in transmission formula rates, with interest.

In February 2024, AEPSC on behalf of the AEP transmission owning subsidiaries within PJM and SPP filed requests for rehearing. In March 2024, the FERC denied AEPSC's requests for rehearing of the January 2024 orders by operation of law and stated it may address the requests for rehearing in future orders. In March 2024, AEPSC submitted refund compliance reports to the FERC, which preserve the non-finality of the FERC's January 2024 orders pending further proceedings on rehearing and appeal. In April 2024, AEPSC made filings with the FERC which requested that the FERC: (a) reopen the record so that the FERC may take the IRS PLRs received in April 2024 regarding the treatment of stand-alone NOLCs in ratemaking into evidence and consider them in substantive orders on rehearing and (b) stay its January 2024 orders and related compliance filings and refunds to provide time for consideration of the April 2024 IRS PLRs. In May 2024, AEPSC filed a petition for review with the United States Court of Appeals for the District of Columbia Circuit seeking review of the FERC's January 2024 and March 2024 decisions. In July 2024, the FERC issued orders approving AEPSC's request to reopen the record for the limited purpose of accepting into the record the IRS PLRs and establish additional briefing procedures. In August 2024, AEPSC filed briefs with the FERC requesting the commission modify or overturn its initial orders.

In June 2025, the FERC issued two orders, partially reversing its January 2024 decisions on the basis of IRS PLRs accepted into the record, and concluding that the accelerated depreciation-related NOLC adjustments should be included in rate base and should also be included in the computation of Excess ADIT regulatory liabilities to be refunded to customers. Requests for rehearing were filed by intervenors in July 2025 and were rejected by 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 are pending the establishment of a procedural schedule.

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, which remain pending before the FERC.

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

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

In October 2023, SWEPCo filed an application to revise its generation wholesale customer's contracts to reflect an increase in the annual revenue requirement of approximately $5 million for updated depreciation rates and allow for the return on and of FERC customers jurisdictional share of regulatory assets associated with retired plants. In November 2023, certain intervenors filed a motion with the FERC protesting and recommending the rejection of SWEPCo's filings. In December 2023, the FERC issued an order approving the proposed rates effective January 1, 2024, subject to further review and refund and established hearing and settlement proceedings. In October 2025, a settlement agreement was filed with the FERC. In November 2025, the settlement judge certified the settlement agreement to the FERC as an uncontested settlement. In January 2026, the FERC issued an order approving the settlement agreement. The order did not have a material impact on SWEPCo's financial condition, results of operations or cash flows.

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. 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 AEP and SWEPCo)

SWEPCo is currently under audit by FERC's Division of Audits and Accounting. The audit is evaluating SWEPCo's compliance with 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. Management is unable to predict the outcome of the audit. 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.

5. EFFECTS OF REGULATION

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

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 December 31, 2025, SWEPCo's share of the net investment in the Pirkey Plant was $206 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. See the "2025 Arkansas Base Rate Case" section of Note 4 for additional information. As of December 31, 2025, the Arkansas jurisdictional share of the net book value of the Pirkey Plant was $41 million.

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 this conclusion in the ALJ's July 2023 PFD. 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 "2025 Texas Base Rate Case" section of Note 4 for additional information. As of December 31, 2025, the Texas jurisdictional share of the net book value of the Pirkey Plant was $76 million. To the extent any portion of the Texas jurisdictional share of the net book value of the Pirkey Plant is not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

Regulated Generating Units to be Retired

PSO

In 2014, PSO received final approval from the Federal EPA to close Northeastern Plant, Unit 3, in 2026. The plant was originally scheduled to close in 2040. As a result of the early retirement date, PSO revised the useful life of Northeastern Plant, Unit 3, to the projected retirement date of 2026 and the incremental depreciation is being deferred as a regulatory asset. Following the 2024 Oklahoma Base Rate Case, PSO continues to recover Northeastern Plant, Unit 3 through 2040. In April 2025, PSO and the ODEQ finalized a second amended regional haze agreement that would allow continued operation of the Northeastern Plant, Unit 3, on natural gas, through May 31, 2041. This agreement is contingent upon approval by the Federal EPA in the form of a revised SIP. The ODEQ is in the process of preparing a SIP submission for the Federal EPA's review and approval.

SWEPCo

In November 2020, management announced that it will cease using coal at the Welsh Plant in 2028. As a result of the announcement, SWEPCo began recording a regulatory asset for accelerated depreciation. In December 2024, SWEPCo filed an application for a CCN with the APSC, LPSC and PUCT to convert Welsh Plant, Units 1 and 3 to natural gas in 2028 and 2027, respectively.

The table below summarizes the net book value including CWIP, before cost of removal and materials and supplies, as of December 31, 2025 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	$ 73	$ 221	$ 21	(b)	2026		(c)	$ 15
Welsh Plant, Units 1 and 3	269	220	56	(d)	2028	(e)	(f)	47

(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 and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	AEP		
	December 31,		Remaining Recovery Period
	2025	2024	
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - does not earn a return	$ 202	$ 116	1 year
Under-recovered Fuel Costs - earns a return	140	246	1 year
Unrecovered Winter Storm Fuel Costs - earns a return (a)	84	84	1 year
Total Current Regulatory Assets	$ 426	$ 446	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Welsh Plant, Units 1 and 3 Accelerated Depreciation	$ 220	$ 169	
Pirkey Plant Accelerated Depreciation	93	121	
Unified Tracker Mechanism Deferred Costs	56	—	
Storm-Related Costs	43	51	
Unrecovered Winter Storm Fuel Costs (a)	—	33	
Other Regulatory Assets Pending Final Regulatory Approval	23	21	
Total Regulatory Assets Currently Earning a Return	435	395	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs (b)	257	357	
Storm-Related Costs (c)	191	301	
2024-2025 Virginia Biennial Under-Earnings (d)	172	78	
NOLC Costs (e)	89	93	
Other Regulatory Assets Pending Final Regulatory Approval	163	87	
Total Regulatory Assets Currently Not Earning a Return	872	916	
Total Regulatory Assets Pending Final Regulatory Approval	1,307	1,311	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant (f)	470	661	21 years
Long-term Under-recovered Fuel Costs - West Virginia	254	284	9 years
Storm-Related Costs	100	107	6 years
Pirkey Plant Accelerated Depreciation - Louisiana	72	66	7 years
Fuel Mine Closure Costs - Texas	65	71	10 years
Pirkey Plant Accelerated Depreciation - Arkansas	41	—	10 years
PJM/SPP Annual Formula Rate True-up	35	—	2 years
Rockport Plant Dry Sorbent Injection System and Selective Catalytic Reduction	28	37	3 years
Texas Mobile Temporary Emergency Electric Energy Facilities Rider	27	33	2 years
Environmental Control Projects	27	29	15 years
Unrecovered Winter Storm Fuel Costs (a)	22	63	2 years
Plant Retirement Costs - Asset Retirement Obligation Costs	1	111	15 years
Kentucky Deferred Purchased Power Expenses	—	45	
Other Regulatory Assets Approved for Recovery	199	204	various
Total Regulatory Assets Currently Earning a Return	1,341	1,711	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	796	974	12 years
Plant Retirement Costs - Asset Retirement Obligation Costs	459	360	17 years
Storm-Related Costs	158	67	6 years
Unamortized Loss on Reacquired Debt	85	91	23 years
Cook Plant Nuclear Refueling Outage Levelization	82	43	3 years
Unrealized Loss on Forward Commitments	69	53	7 years
Ohio Enhanced Service Reliability Plan	58	26	2 years
Plant Retirement Costs - Unrecovered Plant, Texas	45	45	21 years
Smart Grid Costs	44	34	2 years
Renewable Resource Rider	38	—	2 years
Bad Debt Rider	35	22	2 years
West Virginia Environmental Compliance Surcharge	33	26	2 years
Postemployment Benefits	28	28	2 years
Fuel and Purchased Power Adjustment Rider	4	57	2 years
OVEC Purchased Power	—	52	
Other Regulatory Assets Approved for Recovery	222	229	various
Total Regulatory Assets Currently Not Earning a Return	2,156	2,107	
Total Regulatory Assets Approved for Recovery	3,497	3,818	
Total Noncurrent Regulatory Assets	$ 4,804	$ 5,129	

(a) In February 2021, severe winter weather had a significant impact in SPP, resulting in significantly increased market prices for natural gas power plants to meet reliability needs for the SPP electric system. For the time period of February 9, 2021 to February 20, 2021, SWEPCo's natural gas expenses and purchases of electricity still to be recovered from customers are $106 million, of which $22 million, $41 million and $43 million is related to Arkansas, Louisiana and Texas jurisdictions, respectively. Previously, the APSC and PUCT approved recovery with a carrying charge in their jurisdictions over a six-year and five-year period, respectively. In November 2025, the LPSC issued an order approving a recovery period of five years in Louisiana with a carrying charge at the prime rate.
(b) See "Federal EPA's Revised CCR Rule" section of Note 6 for additional information.
(c) Includes $40 million of West Virginia jurisdictional storm operation and maintenance costs as of December 31, 2025 that are subject to a future final securitization financing order from the WVPSC.
(d) In November 2025, the Virginia SCC issued a financing order approving securitization that includes $141 million of storm operation and maintenance costs as of December 31, 2025 that are subject to a final review by the Virginia SCC after bond pricing.
(e) Approved for collection through rates, subject to refund, for the Oklahoma and SWEPCo-Texas jurisdictions.
(f) Amount includes Northeastern Plant, Unit 3 which is approved for recovery through 2040, but expected to retire in 2026. PSO records a regulatory asset for accelerated depreciation. In April 2025, PSO and the ODEQ finalized an agreement, contingent upon approval by the Federal EPA, that would allow the Northeastern Plant, Unit 3, to continue operation on natural gas through May 31, 2041. See "Regulated Generating Units to be Retired" section above for additional information.

	AEP		
	December 31,		Remaining
	2025	2024	Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 54	$ 22	1 year
Over-recovered Fuel Costs - does not pay a return	10	32	1 year
Total Current Regulatory Liabilities	$ 64	$ 54	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ 90	$ 176	
Total Regulatory Liabilities Currently Paying a Return	90	176	
Regulatory Liabilities Currently Not Paying a Return			
FERC 2021 Transmission Formula Rate Challenge Refunds	—	131	
Other Regulatory Liabilities Pending Final Regulatory Determination	29	15	
Total Regulatory Liabilities Currently Not Paying a Return	29	146	
Total Regulatory Liabilities Pending Final Regulatory Determination	119	322	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	4,023	3,828	(b)
Income Taxes, Net (a)	1,048	1,622	(c)
Green Country Contract Liability	59	—	30 years
Rockport Plant, Unit 2 Accelerated Depreciation for Leasehold Improvements	27	36	4 years
Other Regulatory Liabilities Approved for Payment	39	40	various
Total Regulatory Liabilities Currently Paying a Return	5,196	5,526	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	2,557	2,137	(d)
Deferred Investment Tax Credits	64	65	25 years
Demand Side Management	54	53	2 years
Spent Nuclear Fuel	51	50	(d)
Unrealized Gain on Forward Commitments	46	10	3 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	40	2	2 years
Peak Demand Reduction/Energy Efficiency	39	33	2 years
Over-recovered Fuel Costs - Ohio	38	32	7 years
2017-2019 Virginia Triennial Revenue Provision	33	35	24 years
Other Regulatory Liabilities Approved for Payment	125	79	various
Total Regulatory Liabilities Currently Not Paying a Return	3,047	2,496	
Total Regulatory Liabilities Approved for Payment	8,243	8,022	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 8,362	$ 8,344	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Relieved as removal costs are incurred.
(c) Refunded over the period for which the related deferred income taxes reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $269 million and $192 million for the years ended December 31, 2025 and 2024, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2025 is to be refunded over 8 years.
(d) Relieved when plant is decommissioned.

Regulatory Assets:	AEP Texas December 31, 2025	2024	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Unified Tracker Mechanism Deferred Costs	$ 56	$ —	
Storm-Related Costs	41	41	
System Resiliency Plan Deferred Costs	17	—	
Total Regulatory Assets Currently Earning a Return	114	41	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	31	13	
Deferred Pension and OPEB Costs	27	16	
Other Regulatory Assets Pending Final Regulatory Approval	9	7	
Total Regulatory Assets Currently Not Earning a Return	67	36	
Total Regulatory Assets Pending Final Regulatory Approval	181	77	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Texas Mobile Temporary Emergency Electric Energy Facilities Rider	27	33	2 years
Meter Replacement Costs	4	6	2 years
Other Regulatory Assets Approved for Recovery	18	22	various
Total Regulatory Assets Currently Earning a Return	49	61	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	155	178	12 years
Peak Demand Reduction/Energy Efficiency	13	9	2 years
Texas Transmission Cost Recovery Factor	—	14	
Other Regulatory Assets Approved for Recovery	4	15	various
Total Regulatory Assets Currently Not Earning a Return	172	216	
Total Regulatory Assets Approved for Recovery	221	277	
Total Noncurrent Regulatory Assets	$ 402	$ 354	

Regulatory Liabilities:	AEP Texas December 31, 2025	2024	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 880	$ 844	(b)
Income Taxes, Net (a)	373	409	(c)
Other Regulatory Liabilities Approved for Payment	4	5	various
Total Regulatory Liabilities Currently Paying a Return	1,257	1,258	
Regulatory Liabilities Currently Not Paying a Return			
Transition and Restoration Charges	17	22	4 years
Transmission Cost Recovery Factor	7	—	2 years
Other Regulatory Liabilities Approved for Payment	5	5	various
Total Regulatory Liabilities Currently Not Paying a Return	29	27	
Total Regulatory Liabilities Approved for Payment	1,286	1,285	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,286	$ 1,285	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Relieved as removal costs are incurred.
(c) Refunded over the period for which the related deferred income taxes reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $16 million and $22 million for the years ended December 31, 2025 and 2024, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2025 is to be refunded over 4 years.

Regulatory Assets:	AEPTCo December 31, 2025	AEPTCo December 31, 2024	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Income Taxes, Net	$ 9	$ —	
Total Regulatory Assets Pending Final Regulatory Approval	9	—	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Income Taxes, Net	49	—	(a)
PJM/SPP Annual Formula Rate True-up	15	—	2 years
Total Regulatory Assets Approved for Recovery	64	—	
Total Noncurrent Regulatory Assets	$ 73	$ —	

Regulatory Liabilities:	AEPTCo December 31, 2025	AEPTCo December 31, 2024	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (b)	$ —	$ 9	
Total Regulatory Liabilities Pending Final Regulatory Determination	—	9	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	708	582	(c)
Income Taxes, Net (b)	—	287	(d)
Total Regulatory Liabilities Approved for Payment	708	869	
Total Noncurrent Regulatory Liabilities	$ 708	$ 878	

(a) Recovered over the period for which the related deferred income taxes reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements was $6 million for the year ended December 31, 2025 and is to be refunded over 2 years.
(b) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(c) Relieved as removal costs are incurred.
(d) Refunded over the period for which the related deferred income taxes reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements was $9 million for the year ended December 31, 2024.

Regulatory Assets:	APCo December 31, 2025	2024	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs, Virginia - earns a return	$ 71	$ 148	1 year
Under-recovered Fuel Costs, West Virginia - does not earn a return	12	—	1 year
Total Current Regulatory Assets	$ 83	$ 148	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Other Regulatory Assets Pending Final Regulatory Approval	$ 2	$ 1	
Total Regulatory Assets Currently Earning a Return	2	1	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs (a)	169	282	
2024-2025 Virginia Biennial Under-Earnings (b)	172	78	
Storm-Related Costs - West Virginia (c)	39	144	
Pension Settlement	16	18	
Virginia Corporate Alternative Minimum Tax	13	—	
West Virginia Corporate Alternative Minimum Tax	11	—	
Other Regulatory Assets Pending Final Regulatory Approval	18	12	
Total Regulatory Assets Currently Not Earning a Return	438	534	
Total Regulatory Assets Pending Final Regulatory Approval	440	535	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Long-term Under-recovered Fuel Costs - West Virginia	138	154	9 years
Plant Retirement Costs - Unrecovered Plant	64	68	18 years
Excess SO_2 Allowance Inventory	16	—	14 years
Other Regulatory Assets Approved for Recovery	7	5	various
Total Regulatory Assets Currently Earning a Return	225	227	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	404	308	16 years
Storm-Related Costs - West Virginia	107	—	5 years
Pension and OPEB Funded Status	89	108	12 years
Unamortized Loss on Reacquired Debt	63	67	20 years
Virginia Retail Consumable Costs	17	—	2 years
Virginia Transmission Rate Adjustment Clause	16	3	2 years
Virginia Clean Economy Act	16	—	2 years
2020-2022 Virginia Triennial Under-Earnings	14	26	2 years
Postemployment Benefits	13	13	2 years
Vegetation Management Program - West Virginia	12	12	2 years
Peak Demand Reduction/Energy Efficiency	10	14	2 years
Virginia Generation Rate Adjustment Clause	3	12	2 years
Excess SO_2 Allowance Inventory	—	11	14 years
Other Regulatory Assets Approved for Recovery	10	30	various
Total Regulatory Assets Currently Not Earning a Return	774	604	
Total Regulatory Assets Approved for Recovery	999	831	
Total Noncurrent Regulatory Assets	$ 1,439	$ 1,366	

(a) See "Federal EPA's Revised CCR Rule" section of Note 6 for additional information.

(b) In November 2025, the Virginia SCC issued a financing order approving securitization that includes $141 million of storm operation and maintenance costs as of December 31, 2025 that are subject to a final review by the Virginia SCC after bond pricing.

(c) Includes $40 million of West Virginia jurisdictional storm operation and maintenance costs as of December 31, 2025 that are subject to a future final securitization financing order from the WVPSC.

Regulatory Liabilities:	APCo December 31, 2025	2024	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs, West Virginia - does not pay a return	$ —	$ 22	1 year
Total Current Regulatory Liabilities	$ —	$ 22	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ —	$ (6)	
Total Regulatory Liabilities Currently Paying a Return	—	(6)	
Regulatory Liabilities Currently Not Paying a Return			
FERC 2021 Transmission Formula Rate Challenge Refunds	—	25	
Other Regulatory Liabilities Pending Final Regulatory Determination	3	—	
Total Regulatory Liabilities Currently Not Paying a Return	3	25	
Total Regulatory Liabilities Pending Final Regulatory Determination	3	19	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	831	806	(b)
Income Taxes, Net (a)	162	219	(c)
Total Regulatory Liabilities Currently Paying a Return	993	1,025	
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Loss on Forward Commitments	34	8	3 years
2017-2019 Virginia Triennial Revenue Provision	33	35	24 years
Virginia Environmental Rate Adjustment Clause	18	10	2 years
Energy Efficiency Rate Adjustment Clause - Virginia	16	10	2 years
West Virginia Environmental Compliance Surcharge	11	—	2 years
Other Regulatory Liabilities Approved for Payment	3	9	various
Total Regulatory Liabilities Currently Not Paying a Return	115	72	
Total Regulatory Liabilities Approved for Payment	1,108	1,097	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,111	$ 1,116	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Relieved as removal costs are incurred.
(c) Refunded over the period for which the related deferred income taxes reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $11 million and $12 million for the years ended December 31, 2025 and 2024, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2025 is to be refunded over 3 years.

	I&M		
Regulatory Assets:	**December 31, 2025**	**2024**	**Remaining Recovery Period**
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs, Michigan - earns a return	$ —	$ 11	1 year
Total Current Regulatory Assets	$ —	$ 11	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Other Regulatory Assets Pending Final Regulatory Approval	$ 4	$ 6	
Total Regulatory Assets Currently Earning a Return	4	6	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs (a)	78	74	
Storm-Related Costs - Indiana	29	6	
NOLC Costs - Indiana (b)	—	27	
Other Regulatory Assets Pending Final Regulatory Approval	7	2	
Total Regulatory Assets Currently Not Earning a Return	114	109	
Total Regulatory Assets Pending Final Regulatory Approval	118	115	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	73	98	3 years
Rockport Plant Dry Sorbent Injection System and Selective Catalytic Reduction	28	37	3 years
Cook Plant Uprate Project	18	21	8 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan, FERC	9	10	9 years
Cook Plant Turbine - Indiana	7	8	13 years
Other Regulatory Assets Approved for Recovery	22	21	various
Total Regulatory Assets Currently Earning a Return	157	195	
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	165	109	(c)
Cook Plant Nuclear Refueling Outage Levelization	82	43	3 years
NOLC Costs - Indiana (b)	19	—	2 years
Storm-Related Costs - Indiana	14	20	3 years
Unamortized Loss on Reacquired Debt	10	11	23 years
Excess SO_2 Allowance Inventory - Indiana	9	12	3 years
Pension and OPEB Funded Status	—	15	
Other Regulatory Assets Approved for Recovery	11	28	various
Total Regulatory Assets Currently Not Earning a Return	310	238	
Total Regulatory Assets Approved for Recovery	467	433	
Total Noncurrent Regulatory Assets	$ 585	$ 548	

(a) See "Federal EPA's Revised CCR Rule" section of Note 6 for additional information.
(b) In the first quarter of 2025, the IURC approved the stand-alone treatment of NOLCs.
(c) Recovered over the period for which the related deferred income taxes reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $6 million and $12 million for the years ended December 31, 2025 and 2024, respectively, and is to be refunded over 2 years.

Regulatory Liabilities:	I&M December 31, 2025	I&M December 31, 2024	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs, Indiana - does not pay a return	$ 10	$ 10	1 year
Over-recovered Fuel Costs, Michigan - pays a return	9	—	1 year
Total Current Regulatory Liabilities	$ 19	$ 10	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Not Paying a Return			
Cook Plant PTC Deferral - Michigan	$ 26	$ 15	
FERC 2021 Transmission Formula Rate Challenge Refunds	—	29	
Other Regulatory Liabilities Pending Final Regulatory Determination	1	—	
Total Regulatory Liabilities Currently Not Paying a Return	27	44	
Total Regulatory Liabilities Pending Final Regulatory Determination	27	44	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	172	174	(a)
Renewable Energy Surcharge - Michigan	22	24	2 years
Other Regulatory Liabilities Approved for Payment	7	—	various
Total Regulatory Liabilities Currently Paying a Return	201	198	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	2,557	2,137	(b)
Spent Nuclear Fuel	51	50	(b)
PJM Costs and Off-system Sales Margin Sharing - Indiana	35	2	2 years
Demand Side Management - Indiana	31	33	2 years
Pension and OPEB Funded Status	15	—	12 years
Deferred Investment Tax Credits	13	14	25 years
Other Regulatory Liabilities Approved for Payment	8	3	various
Total Regulatory Liabilities Currently Not Paying a Return	2,710	2,239	
Total Regulatory Liabilities Approved for Payment	2,911	2,437	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 2,938	$ 2,481	

(a) Relieved as removal costs are incurred.
(b) Relieved when plant is decommissioned.

Regulatory Assets:	OPCo December 31, 2025	OPCo December 31, 2024	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Ohio Basic Transmission Cost Rider	$ 12	$ 26	2 years
Other Regulatory Assets Approved for Recovery	2	—	various
Total Regulatory Assets Currently Earning a Return	14	26	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	111	134	12 years
Ohio Enhanced Service Reliability Plan	58	26	2 years
Smart Grid Costs	44	34	2 years
Unrealized Loss on Forward Commitments	33	48	7 years
Bad Debt Rider	27	14	2 years
Storm-Related Costs	18	29	2 years
Ohio Basic Transmission Cost Rider	14	—	2 years
OVEC Purchased Power	—	52	
Ohio Distribution Investment Rider	—	11	
Other Regulatory Assets Approved for Recovery	7	5	various
Total Regulatory Assets Currently Not Earning a Return	312	353	
Total Regulatory Assets Approved for Recovery	326	379	
Total Noncurrent Regulatory Assets	$ 326	$ 379	

Regulatory Liabilities:	OPCo		
	December 31, 2025	December 31, 2024	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ 77	$ —	
Total Regulatory Liabilities Currently Paying a Return	77	—	
Regulatory Liabilities Currently Not Paying a Return			
FERC 2021 Transmission Formula Rate Challenge Refunds	—	73	
Total Regulatory Liabilities Currently Not Paying a Return	—	73	
Total Regulatory Liabilities Pending Final Regulatory Determination	77	73	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	470	480	(b)
Income Taxes, Net (a)	271	368	(c)
Other Regulatory Liabilities Approved for Payment	1	4	various
Total Regulatory Liabilities Currently Paying a Return	742	852	
Regulatory Liabilities Currently Not Paying a Return			
Over-recovered Fuel Costs	38	32	7 years
Peak Demand Reduction/Energy Efficiency	23	23	2 years
Other Regulatory Liabilities Approved for Payment	13	8	various
Total Regulatory Liabilities Currently Not Paying a Return	74	63	
Total Regulatory Liabilities Approved for Payment	816	915	
Total Noncurrent Regulatory Liabilities	$ 893	$ 988	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Relieved as removal costs are incurred.
(c) Refunded over the period for which the related deferred income taxes reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $14 million and $100 million for the years ended December 31, 2025 and 2024, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2025 is to be refunded over 2 years.

	PSO		
	December 31,		Remaining Recovery Period
Regulatory Assets:	2025	2024	
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 37	$ 65	1 year
Total Current Regulatory Assets	$ 37	$ 65	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	$ 25	$ 5	
NOLC Costs (a)	23	16	
Generation PBA and Delayed Retirement Deferral	13	—	
Other Regulatory Assets Pending Final Regulatory Approval	23	9	
Total Regulatory Assets Pending Final Regulatory Approval	84	30	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant (b)	302	274	21 years
Storm-Related Costs	90	107	6 years
Environmental Control Projects	20	21	15 years
Meter Replacement Costs	6	10	2 years
Other Regulatory Assets Approved for Recovery	16	14	various
Total Regulatory Assets Currently Earning a Return	434	426	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	41	58	12 years
Renewable Resources Rider	38	—	2 years
Unrealized Loss on Forward Commitments	28	4	2 years
Other Regulatory Assets Approved for Recovery	12	10	various
Total Regulatory Assets Currently Not Earning a Return	119	72	
Total Regulatory Assets Approved for Recovery	553	498	
Total Noncurrent Regulatory Assets	$ 637	$ 528	

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

(b) Amount includes Northeastern Plant, Unit 3 which is approved for recovery through 2040, but expected to retire in 2026. PSO records a regulatory asset for accelerated depreciation. In April 2025, PSO and the ODEQ finalized an agreement, contingent upon approval by the Federal EPA, that would allow the Northeastern Plant, Unit 3, to continue operation on natural gas through May 31, 2041. See "Regulated Generating Units to be Retired" section above for additional information.

Regulatory Liabilities:	PSO December 31, 2025	2024	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Not Paying a Return			
FERC 2021 Transmission Formula Rate Challenge Refunds	$ —	$ 2	
Total Regulatory Liabilities Pending Final Regulatory Determination	—	2	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	323	324	(a)
Income Taxes, Net (b)	285	318	(c)
Green Country Contract Liability	59	—	30 years
Total Regulatory Liabilities Currently Paying a Return	667	642	
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	47	46	11 years
Other Regulatory Liabilities Approved for Payment	3	—	various
Total Regulatory Liabilities Currently Not Paying a Return	50	46	
Total Regulatory Liabilities Approved for Payment	717	688	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 717	$ 690	

(a) Relieved as removal costs are incurred.
(b) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(c) Refunded over the period for which the related deferred income taxes reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $41 million and $46 million for the years ended December 31, 2025 and 2024, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2025 is to be refunded over 8 years.

Regulatory Assets:	SWEPCo December 31, 2025	SWEPCo December 31, 2024	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Unrecovered Winter Storm Fuel Costs - earns a return (a)	$ 84	$ 84	1 year
Under-recovered Fuel Costs - earns a return (b)	31	23	1 year
Total Current Regulatory Assets	$ 115	$ 107	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Welsh Plant, Units 1 and 3 Accelerated Depreciation	$ 220	$ 169	
Pirkey Plant Accelerated Depreciation	93	121	
Storm-Related Costs	2	10	
Unrecovered Winter Storm Fuel Costs (a)	—	33	
Dolet Hills Power Station Accelerated Depreciation (c)	—	12	
Other Regulatory Assets Pending Final Regulatory Approval	1	1	
Total Regulatory Assets Currently Earning a Return	316	346	
Regulatory Assets Currently Not Earning a Return			
NOLC Costs (d)	66	50	
Storm-Related Costs - Louisiana, Texas	43	40	
Other Regulatory Assets Pending Final Regulatory Approval	20	18	
Total Regulatory Assets Currently Not Earning a Return	129	108	
Total Regulatory Assets Pending Final Regulatory Approval	445	454	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Pirkey Plant Accelerated Depreciation - Louisiana	72	66	7 years
Fuel Mine Closure Costs - Texas	65	71	10 years
Pirkey Plant Accelerated Depreciation - Arkansas	41	—	10 years
Plant Retirement Costs - Unrecovered Plant - Arkansas, Louisiana	31	40	17 years
Unrecovered Winter Storm Fuel Costs (a)	22	63	2 years
Plant Retirement Costs - Unrecovered Plant, Dolet Hills Power Station - Louisiana	15	19	7 years
Dolet Hills Power Station Fuel Costs - Louisiana	14	22	2 years
Dolet Hills Power Station Accelerated Depreciation (c)	13	—	21 years
Storm-Related Costs - Arkansas	10	—	3 years
Other Regulatory Assets Approved for Recovery	18	12	various
Total Regulatory Assets Currently Earning a Return	301	293	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	77	93	12 years
Plant Retirement Costs - Unrecovered Plant, Texas	45	45	21 years
Plant Retirement Costs - Unrecovered Plant, Arkansas	10	13	2 years
Other Regulatory Assets Approved for Recovery	25	23	various
Total Regulatory Assets Currently Not Earning a Return	157	174	
Total Regulatory Assets Approved for Recovery	458	467	
Total Noncurrent Regulatory Assets	$ 903	$ 921	

(a) In February 2021, severe winter weather had a significant impact in SPP, resulting in significantly increased market prices for natural gas power plants to meet reliability needs for the SPP electric system. For the time period of February 9, 2021 to February 20, 2021, SWEPCo's natural gas expenses and purchases of electricity still to be recovered from customers are $106 million, of which $22 million, $41 million and $43 million is related to Arkansas, Louisiana and Texas jurisdictions, respectively. Previously, the APSC and PUCT approved recovery with a carrying charge in their jurisdictions over a six-year and five-year period, respectively. In November 2025, the LPSC issued an order approving a recovery period of five years in Louisiana with a carrying charge at the prime rate.

(b) 2025 amount related to Arkansas and Texas jurisdictions. 2024 amount related to Arkansas, Louisiana and Texas jurisdictions.

(c) Amounts include the FERC jurisdiction.

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

Regulatory Liabilities:	SWEPCo December 31, 2025	SWEPCo December 31, 2024	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return (a)	$ 45	$ 22	1 year
Total Current Regulatory Liabilities	$ 45	$ 22	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (b)	$ 7	$ 7	
Total Regulatory Liabilities Pending Final Regulatory Determination	7	7	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	459	457	(c)
Income Taxes, Net (b)	24	128	(d)
Other Regulatory Liabilities Approved for Payment	6	7	various
Total Regulatory Liabilities Currently Paying a Return	489	592	
Regulatory Liabilities Currently Not Paying a Return			
Demand Side Management	11	9	2 years
Other Regulatory Liabilities Approved for Payment	24	3	various
Total Regulatory Liabilities Currently Not Paying a Return	35	12	
Total Regulatory Liabilities Approved for Payment	524	604	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 531	$ 611	

(a) 2025 amount related to Louisiana and Texas jurisdictions. 2024 amount related to Texas jurisdiction.
(b) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(c) Relieved as removal costs are incurred.
(d) Refunded over the period for which the related deferred income taxes reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets.

6. 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.

COMMITMENTS (Applies to all Registrants except AEP Texas and AEPTCo)

AEP subsidiaries have substantial commitments for fuel, energy and capacity contracts as part of the normal course of business. Certain contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following tables summarize the Registrants' actual contractual commitments as of December 31, 2025:

Contractual Commitments - AEP	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 1,103	$ 1,560	$ 338	$ 241	$ 3,242
Energy and Capacity Purchase Contracts	153	329	292	294	1,068
Construction Contract for Capital Assets (b)	600	725	—	—	1,325
Total	$ 1,856	$ 2,614	$ 630	$ 535	$ 5,635

Contractual Commitments - APCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 489	$ 808	$ 126	$ 35	$ 1,458
Energy and Capacity Purchase Contracts	39	71	43	33	186
Total	$ 528	$ 879	$ 169	$ 68	$ 1,644

Contractual Commitments - I&M	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 261	$ 382	$ 200	$ 203	$ 1,046
Energy and Capacity Purchase Contracts	113	242	149	205	709
Total	$ 374	$ 624	$ 349	$ 408	$ 1,755

Contractual Commitments - OPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Energy and Capacity Purchase Contracts	$ 31	$ 66	$ 60	$ 43	$ 200

Contractual Commitments - PSO	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 28	$ 12	$ —	$ —	$ 40
Energy and Capacity Purchase Contracts	45	71	36	13	165
Total	$ 73	$ 83	$ 36	$ 13	$ 205

Contractual Commitments - SWEPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 102	$ 72	$ —	$ —	$ 174
Energy and Capacity Purchase Contracts	7	2	—	—	9
Total	$ 109	$ 74	$ —	$ —	$ 183

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.

(b) In January 2026, an unregulated AEP subsidiary entered into an agreement to acquire solid oxide fuel cells for approximately $2.65 billion. This is not included in the presented commitments as of December 31, 2025.

GUARANTEES

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

Letters of Credit (Applies to AEP)

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

AEP has $5 billion and $1 billion revolving credit facilities due in March 2029 and March 2027, respectively. AEP may issue up to $1.2 billion as letters of credit under these revolving credit facilities on behalf of subsidiaries. As of December 31, 2025, no letters of credit were issued under the revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $450 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of December 31, 2025 were as follows:

Company	Amount	Maturity
	(in millions)	
AEP	$ 377	January 2026 to November 2026

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2025, there were no material liabilities recorded for any indemnifications.

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

Lease Obligations

Certain Registrants lease equipment under master lease agreements. See "Master Lease Agreements" section of Note 13 for additional information.

ENVIRONMENTAL CONTINGENCIES (Applies to All Registrants except AEPTCo)

Federal EPA's Revised CCR Rule

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

Registrant	Increase in ARO	Increase in Generation Property (a)	Increase in Regulatory Assets (b)	Charged to Operating Expenses (c)
		(in millions)		
APCo	$ 312	$ 75	$ 237	$ —
I&M	85	—	72	13
OPCo	53	—	—	53
PSO	34	34	—	—
SWEPCo	24	24	—	—
Non-Registrants	166	44	46	76
Total	$ 674	$ 177	$ 355	$ 142

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

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

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. Several parties, including AEP and one of its trade associations, have filed petitions for review of the Legacy CCR Rule with the U.S. Court of Appeals for the District of Columbia Circuit. The litigation is being held in abeyance. In December 2025, the Federal EPA informed the court that it anticipates publishing a proposed rule in January 2026 that should be finalized by October 2026, which will revise certain provisions of the Legacy CCR Rule for both legacy CCR surface impoundments and CCR management units. The Federal EPA further noted that it has been working to obtain technical information to inform its reconsideration and develop a record to support a proposal. Reconsideration of the rule will require a new round of notice-and-comment rulemaking.

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. Management cannot predict the outcome of the litigation or any further actions by the Federal EPA related to the rule.

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

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and non-hazardous materials. The Registrants currently incur costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2025, AGR, APCo, OPCo and SWEPCo are named as a Potentially Responsible Party (PRP) for one, one, two and one sites, respectively, by the Federal EPA for which alleged liability is unresolved. There are 11 additional sites for which APCo, I&M, KPCo, OPCo and SWEPCo received information requests which could lead to PRP designation. In those instances where a PRP or defendant has been named, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each Superfund site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. As of December 31, 2025, management's estimates do not anticipate material clean-up costs for identified Superfund sites.

NUCLEAR CONTINGENCIES (APPLIES TO AEP AND I&M)

I&M owns and operates the two-unit 2,296 MW Cook Plant under licenses granted by the NRC. I&M has a significant future financial obligation 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.

Decommissioning and Low-Level Waste Accumulation Disposal

The costs to decommission a nuclear plant are affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of Cook Plant. The most recent decommissioning cost study was performed in 2024. According to that study, stated in 2024 undiscounted dollars, the estimated cost of decommissioning and disposal of low-level radioactive waste was $2.4 billion, with additional ongoing costs of $7 million per year for post decommissioning storage of SNF and an eventual cost of $45 million for the subsequent decommissioning of the SNF storage facility. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. Decommissioning contributions received from customers are deposited in external trusts. Based on the funded status of the trusts, contributions were not collected from customers in 2025.

As of December 31, 2025 and 2024, the total decommissioning trust fund balances were $4.5 billion and $4 billion, respectively. The increase in the trust fund balance was driven by favorable investment performance in 2025. Trust fund earnings increase the fund assets and may decrease the amount remaining to be recovered from customers. Trust fund losses decrease the fund assets and may increase the amount remaining to be recovered from customers. The decommissioning costs (including unrealized gains and losses, interest and trust funds expenses) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to establish rates designed to collect the estimated costs of decommissioning the Cook Plant. However, future net income and cash flows would be reduced and financial condition could be impacted if the cost of SNF disposal and decommissioning increases and cannot be recovered.

Spent Nuclear Fuel Disposal

The federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one-mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant was collected from customers and remitted to the DOE through May 14, 2014. In May 2014, pursuant to court order from the U.S Court of Appeals for the District of Columbia Circuit, the DOE adjusted the fee to $0. As of December 31, 2025 and 2024, fees and related interest of $330 million and $316 million, respectively, for fuel consumed prior to April 7, 1983 were recorded as Long-term Debt and funds collected from customers along with related earnings totaling $381 million and $367 million, respectively, to pay the fee, were recorded as part of Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government’s delay in accepting SNF for permanent storage. Under the settlement agreement, I&M received $11 million, $12 million and $21 million in 2025, 2024 and 2023, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2025. The proceeds reduced costs for dry cask storage. As of December 31, 2025 and 2024, I&M deferred $25 million and $11 million, respectively, in Prepayments and Other Current Assets and $1 million and $15 million, respectively, in Deferred Charges and Other Noncurrent Assets on the balance sheets for dry cask storage and related operation and maintenance costs for recovery under this agreement. See “Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal” section of Note 11 for additional information.

Nuclear Insurance

I&M carries nuclear property insurance of $2.7 billion to cover a nuclear incident at Cook Plant including coverage for decontamination and stabilization, as well as premature decommissioning caused by a nuclear incident. Insurance coverage for a nonnuclear property incident at Cook Plant is $1 billion. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Coverage from these industry mutual insurance programs require a contingent financial obligation of up to $49 million for I&M’s current term, which is assessable if the insurer’s financial resources would be inadequate to pay for industry losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public nuclear liability arising from a nuclear incident of $16.3 billion and applies to any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $500 million of primary coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $332 million per nuclear incident on Cook Plant’s reactors payable in annual installments of $49 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is covered for public nuclear liability for the first $500 million through commercially available insurance. The next level of liability coverage of up to $15.8 billion would be covered by deferred premium assessments made under the Price-Anderson Act. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds, I&M would seek recovery of those amounts from customers through a rate increase. If recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

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. See "Nuclear Contingencies" section above for additional information.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cybersecurity incident, extreme weather or wildfire related liabilities or damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered through 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 EPA 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 dismissed the complaint at the Federal EPA's request. 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.

7. ACQUISITIONS, DISPOSITIONS AND IMPAIRMENTS

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

ACQUISITIONS

Wagon Wheel Wind Facility (Applies to AEP and SWEPCo)

In December 2025, SWEPCo acquired 100% of the equity interests in Wagon Wheel Project, LLC, the owner of the newly constructed Wagon Wheel wind facility located across multiple counties in Oklahoma. This facility, placed in service in December 2025, serves both retail and wholesale customers in Arkansas and Louisiana. SWEPCo's Louisiana jurisdictional share of the Wagon Wheel revenue requirement, net of PTC benefit, is recoverable through an authorized rider until the amounts are reflected in base rates. Recovery of the Arkansas portion of the Wagon Wheel revenue requirement began in February 2026 through base rates. Regulatory commission approval of the inclusion of the output from Wagon Wheel in retail rates resulted in various capital cost, performance and other guarantees for retail customers which could subject SWEPCo to future regulatory liabilities to retail customers.

The acquisition of Wagon Wheel 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 that the acquisition represents an asset acquisition. The table below summarizes the impact at acquisition on SWEPCo's balance sheets:

Plant Name	State	Fuel Type	Net Maximum Capacity (MWs)	Property, Plant and Equipment, Net	Operating Lease Assets	Asset Retirement Obligations
					(in millions)	
Wagon Wheel	OK	Wind	598	$ 1,272	$ 66	$ 20

Top Hat Wind Facility (Applies to AEP and APCo)

In November 2025, APCo acquired 100% of the equity interests in Top Hat Wind Energy, LLC, the owner of the newly constructed Top Hat wind facility located in Logan County, Illinois. This facility, placed in service in November 2025, serves both retail and wholesale customers in Virginia and West Virginia. Virginia and West Virginia jurisdictional shares of the Top Hat revenue requirement, net of PTC benefit, is recoverable through existing riders until the amounts are reflected in base rates. The acquisition of Top Hat 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 acquisition represents an asset acquisition. The table below summarizes the impact at acquisition on APCo's balance sheets:

Plant Name	State	Fuel Type	Net Maximum Capacity (MWs)	Property, Plant and Equipment, Net	Operating Lease Assets	Asset Retirement Obligations
					(in millions)	
Top Hat	IL	Wind	204	$ 562	$ 31	$ 4

Green Country Power Plant, Pixley Solar Energy Facility, Flat Ridge IV Wind Energy Facility and Flat Ridge V Wind Energy Facility (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 represent asset acquisitions.

Additionally, in June 2025, PSO completed the acquisition of 100% of the equity interests in Green Country Energy, LLC, the owner of a combined-cycle natural gas facility located in Jenks, Oklahoma, following approvals from both the FERC and the OCC. The transaction included the acquisition of a previously executed capacity sales agreement between Green Country Energy, LLC, as seller, and SWEPCo, as purchaser. 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 represents an asset acquisition. Asset acquisitions are accounted for using a cost accumulation model, with the cost of the acquisition allocated to the acquired assets and assumed liabilities based on their relative fair value. Upon closing of the transaction, PSO recognized Property, Plant and Equipment of $819 million, an intangible liability of $41 million for the fair value of the acquired SWEPCo capacity sales agreement and a regulatory liability of $50 million, reflective of the recognition and subsequent deferral of the gain from PSO's extinguished capacity sales agreement. The liabilities recognized for the capacity sales agreements will reduce PSO's revenue requirement to recover its overall investment in Green Country, which is recoverable through a rider authorized by the OCC until it is included in base rates for the depreciable life of the facility. 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.

Furthermore, in August 2025, PSO completed the acquisition of 100% of the equity interests in Flat Ridge V Wind Energy, LLC, the owner of the Flat Ridge V Wind Energy Facility located in Kingman and Harper Counties, Kansas. This facility, placed in service in August 2025, serves both retail and wholesale customers under similar recovery and regulatory provisions as the Flat Ridge IV and Pixley facilities. The acquisition of Flat Ridge V 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 acquisition of Flat Ridge V represents an asset acquisition.

In 2025, PSO expanded its generation portfolio by acquiring four electric generation facilities for an aggregate purchase price of $1.7 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)			
Green Country	OK	Natural Gas	904	$ 819	$ —	$ —	$ 91	(a)
Pixley	KS	Solar	189	380	9	12	—	
Flat Ridge IV	KS	Wind	135	305	7	3	—	
Flat Ridge V	KS	Wind	153	338	9	4	—	
Total			1,381	$ 1,842	$ 25	$ 19	$ 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.

Diversion Wind Farm (Applies to AEP and SWEPCo)

In December 2024, SWEPCo acquired 100% of the equity interests in Diversion Wind Energy, LLC, the owner of Diversion wind farm. The Diversion wind farm is a newly constructed 201 MW wind facility located in Baylor County, Texas and was placed in service in December 2024. Output from Diversion serves both retail and wholesale customers in Arkansas and Louisiana. SWEPCo's Louisiana jurisdictional share of the Diversion revenue requirement, net of PTC benefit, is recoverable through an authorized rider until the amounts are reflected in base rates. Recovery of the Arkansas portion of the Diversion revenue requirement is expected to begin in 2026 through base rates. Regulatory commission approval of the inclusion of the output from Diversion in retail rates resulted in various capital cost, performance and other guarantees for retail customers which could subject SWEPCo to future regulatory liabilities to retail customers.

In accordance with the guidance for "Business Combinations," management determined that the acquisition of the Diversion project represents an asset acquisition. As of December 31, 2024, SWEPCo had approximately $423 million of gross Property, Plant and Equipment, inclusive of capital expenditures after the acquisition, on the balance sheets related to the Diversion project. The acquisition also resulted in the recognition of $20 million of operating leases that provide for easement and access rights to the land that Diversion was built upon and $6 million of ARO.

Rock Falls Wind Facility (Applies to AEP and PSO)

In November 2022, PSO entered into an agreement to acquire the Rock Falls Wind Facility. In February 2023, the FERC approved PSO's acquisition of the Rock Falls Wind Facility under Section 203 of the Federal Power Act. In March 2023, PSO acquired an ownership interest in the entity that owned Rock Falls during its development and construction for $146 million. In accordance with the guidance for "Business Combinations," AEP management determined that the acquisition of the Rock Falls Wind Facility represents an asset acquisition. The lease obligations related to Rock Falls were not material at the time of acquisition.

DISPOSITIONS

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. AEP received cash proceeds of approximately $2.78 billion, net of transaction costs. Net proceeds were used to help finance AEP's capital plan.

Disposition of AEP OnSite Partners (Applies to AEP)

In April 2023, AEP initiated a sales process for its ownership in AEP OnSite Partners. AEP OnSite Partners targeted opportunities in distributed solar, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other energy solutions. In May 2024, AEP signed an agreement to sell AEP OnSite Partners to a nonaffiliated third-party. In September 2024, AEP completed the sale and received cash proceeds of approximately $318 million, net of taxes and transaction costs. The proceeds were used to pay down short-term debt.

Disposition of NMRD (Applies to AEP)

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

Disposition of the Competitive Contracted Renewables Portfolio (Applies to AEP)

In February 2022, AEP management announced the initiation of a process to sell all or a portion of AEP Renewables' competitive contracted renewables portfolio (the portfolio) within the Generation & Marketing segment. In late January 2023, AEP received final bids from interested parties. In February 2023, AEP's Board of Directors approved management's plan to sell the portfolio and AEP signed an agreement with a nonaffiliated party.

In August 2023, AEP completed the sale of the entire portfolio to the nonaffiliated party and received cash proceeds of approximately $1.2 billion, net of taxes and transaction costs. AEP recorded a pretax loss of $93 million ($73 million after-tax) for the year ended December 31, 2023 related to the sale.

IMPAIRMENTS

Internal-Use Software Impairment (Applies to all Registrants Except AEPTCo)

In the fourth quarter of 2025, as a result of evaluation of AEP's strategy and expectations for ongoing advancements in available technologies, including the expanded use of, and potential capabilities for, AI-centric software and other agile software functionality, AEP Management determined that previously selected technology for an in-process software development project to replace a legacy enterprise system was no longer probable of being completed and placed in service. As a result, the guidance for "Internal Use Software" requires the related capitalized costs to be reported at the lower of their carrying amount or fair value, if any, less costs to sell. AEP Management concluded the previously incurred application development costs have a fair value of zero and recognized a charge of $66 million recorded in Asset Impairments and Other Related Charges on the statements of income in the fourth quarter of 2025.

2012 Texas Base Rate Case (Applies to AEP and SWEPCo)

In December 2023, SWEPCo recorded a pretax, non-cash disallowance of $86 million in Asset Impairments and Other Related Charges on the statements of income due to regulatory disallowance of recovery of AFUDC on Turk Plant in the 2012 Texas Base Rate case.

NMRD (Applies to AEP)

In December 2023, as a result of sale negotiations AEP determined a decline in the fair value of AEP's investment in NMRD was other than temporary. In accordance with the accounting guidance for "Investment - Equity Method and Joint Ventures", in the fourth quarter of 2023 AEP recorded a pretax other than temporary impairment charge of $19 million which is presented in Equity Earnings (Losses) of Unconsolidated Subsidiaries on AEP's statement of income. AEP's determination of fair value utilized the accounting guidance for Fair Value Measurement market approach to valuation and was based on negotiations to sell the investment to a nonaffiliated third-party. The carrying value of the investment in NMRD was not material to AEP as of December 31, 2023.

8. BENEFIT PLANS

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

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see “Fair Value Measurements of Assets and Liabilities” and “Investments Held in Trust for Future Liabilities” sections of Note 1.

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.

Due to the Registrant Subsidiaries’ participation in AEP’s benefit plans, the assumptions used by the actuary, with the exception of the rate of compensation increase, and the accounting for the plans by each subsidiary are the same. This section details the assumptions that apply to all Registrants and the rate of compensation increase for each Registrant.

The Registrants recognize the funded status associated with defined benefit pension and OPEB plans on the balance sheets. Disclosures about the plans are required by the “Compensation – Retirement Benefits” accounting guidance. The Registrants recognize an asset for a plan’s overfunded status or a liability for a plan’s underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. The Registrants record a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions used in the measurement of the Registrants’ benefit obligations are shown in the following tables:

	Pension Plans		OPEB	
	December 31,			
Assumption	**2025**	**2024**	**2025**	**2024**
Discount Rate	5.50 %	5.65 %	5.50 %	5.60 %
Interest Crediting Rate	4.40 %	4.55 %	NA	NA

NA Not applicable.

Assumption – Rate of Compensation Increase (a) - Pension Plans

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
December 31, 2025	4.55 %	4.50 %	4.50 %	4.45 %	4.80 %	4.65 %	4.50 %
December 31, 2024	5.55 %	5.70 %	5.55 %	5.50 %	6.00 %	5.70 %	5.55 %

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate is the same for each Registrant.

For 2025, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with the average increase shown in the table above. The compensation increase rates reflect variations in each Registrants’ population participating in the pension plan.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions used in the measurement of each Registrants' benefit costs are shown in the following tables:

	Pension Plans			OPEB		
	Year Ended December 31,					
Assumption	2025	2024	2023	2025	2024	2023
Discount Rate	5.65 %	5.20 %	5.50 %	5.60 %	5.15 %	5.50 %
Interest Crediting Rate	4.55 %	4.05 %	4.25 %	NA	NA	NA
Expected Return on Plan Assets	7.00 %	7.30 %	7.50 %	6.50 %	6.75 %	7.25 %

NA Not applicable.

	Assumption – Rate of Compensation Increase (a) - Pension Plans						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
December 31, 2025	5.75 %	5.90 %	5.80 %	5.60 %	6.10 %	5.90 %	5.70 %
December 31, 2024	5.10 %	5.25 %	5.10 %	5.10 %	5.50 %	5.20 %	5.10 %
December 31, 2023	5.05 %	5.20 %	4.95 %	5.05 %	5.45 %	5.20 %	5.00 %

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, third-party forecasts and current prospects for economic growth. The expected return on plan assets is the same for each Registrant.

The health care trend rate assumptions used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	December 31, 2025	December 31, 2024
Initial	6.00 %	6.50 %
Ultimate	4.50 %	4.50 %
Year Ultimate Reached	2031	2029

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and compliance with the investment policy. As of December 31, 2025, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets, Funded Status and Amounts Recognized on the Balance Sheets

For the year ended December 31, 2025, the pension plans had an actuarial loss primarily due to a decrease in discount rates, and to a lesser extent the effect of demographic experience (updated census data on January 1, 2025). These losses were partially offset by decreasing the cash balance account interest crediting rate. For the year ended December 31, 2025, the OPEB plans had an actuarial gain primarily due to updated per capita cost assumptions (notably including guidance on Employer Group Waiver Plan subsidies as a result of Inflation Reduction Act). These gains were partially offset by updated discount and trend rates. For the year ended December 31, 2024, the pension plans had an actuarial gain primarily due to an increase in discount rates, and to a lesser extent the effect of demographic experience (updated census data on January 1, 2024). These gains were partially offset by increasing the cash balance account interest crediting rate, increasing the rate used to convert lump sums to annuities and updating the compensation increase rate to reflect the results of an experienced study conducted in 2024. For the year ended December 31, 2024, the OPEB plans had an actuarial gain primarily due to updated per capita cost assumptions and updated discount rates. These gains were partially offset by the addition of a life insurance administrative load of 5%, the effect of special termination benefits and earlier retirements due to the voluntary severance program that occurred in the second quarter of 2024 and assumption changes as a result of an experience study conducted in 2024.

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

Pension Plans

2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Change in Benefit Obligation				(in millions)			
Benefit Obligation as of January 1,	$ 3,872	$ 323	$ 453	$ 450	$ 351	$ 190	$ 228
Service Cost	96	9	9	13	9	6	8
Interest Cost	211	17	25	25	19	10	13
Actuarial Loss	46	7	11	5	6	2	4
Benefit Payments	(382)	(29)	(43)	(45)	(39)	(18)	(20)
Benefit Obligation as of December 31,	$ 3,843	$ 327	$ 455	$ 448	$ 346	$ 190	$ 233
Change in Fair Value of Plan Assets							
Fair Value of Plan Assets as of January 1,	$ 3,666	$ 288	$ 488	$ 507	$ 381	$ 200	$ 189
Actual Gain on Plan Assets	372	32	53	50	39	21	22
Company Contributions (a)	103	12	—	2	—	2	9
Benefit Payments	(382)	(29)	(43)	(45)	(39)	(18)	(20)
Fair Value of Plan Assets as of December 31,	$ 3,759	$ 303	$ 498	$ 514	$ 381	$ 205	$ 200
Funded (Underfunded) Status as of December 31,	$ (84)	$ (24)	$ 43	$ 66	$ 35	$ 15	$ (33)

2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Change in Benefit Obligation				(in millions)			
Benefit Obligation as of January 1,	$ 4,162	$ 343	$ 504	$ 477	$ 378	$ 202	$ 261
Service Cost	101	9	9	13	9	6	8
Interest Cost	207	17	25	24	19	10	12
Actuarial (Gain) Loss	(45)	6	(13)	(8)	(8)	—	(11)
Settlements	(329)	(35)	(42)	(33)	(23)	(18)	(33)
Benefit Payments	(224)	(17)	(30)	(23)	(24)	(10)	(9)
Benefit Obligation as of December 31,	$ 3,872	$ 323	$ 453	$ 450	$ 351	$ 190	$ 228
Change in Fair Value of Plan Assets							
Fair Value of Plan Assets as of January 1,	$ 4,118	$ 333	$ 550	$ 551	$ 419	$ 223	$ 227
Actual Gain on Plan Assets	87	7	10	12	9	5	4
Company Contributions (a)	14	—	—	—	—	—	—
Settlements	(329)	(35)	(42)	(33)	(23)	(18)	(33)
Benefit Payments	(224)	(17)	(30)	(23)	(24)	(10)	(9)
Fair Value of Plan Assets as of December 31,	$ 3,666	$ 288	$ 488	$ 507	$ 381	$ 200	$ 189
Funded (Underfunded) Status as of December 31,	$ (206)	$ (35)	$ 35	$ 57	$ 30	$ 10	$ (39)

(a) Contributions to the qualified pension plan were $95 million for the year ended December 31, 2025. No contributions were made to the qualified pension plan for the year ended December 31, 2024. Contributions to the non-qualified pension plans were $8 million and $14 million for the years ended December 31, 2025 and 2024, respectively.

OPEB

2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Change in Benefit Obligation				(in millions)			
Benefit Obligation as of January 1,	$ 647	$ 50	$ 102	$ 73	$ 63	$ 33	$ 41
Service Cost	4	—	1	—	—	—	—
Interest Cost	34	3	5	4	3	2	2
Actuarial (Gain) Loss	(50)	(1)	(8)	(5)	(4)	(2)	(2)
Benefit Payments	(105)	(9)	(17)	(13)	(11)	(6)	(7)
Participant Contributions	46	3	7	6	5	3	3
Benefit Obligation as of December 31,	$ 576	$ 46	$ 90	$ 65	$ 56	$ 30	$ 37
Change in Fair Value of Plan Assets							
Fair Value of Plan Assets as of January 1,	$ 1,776	$ 147	$ 256	$ 212	$ 185	$ 95	$ 121
Actual Gain on Plan Assets	262	27	39	32	24	17	21
Company Contributions	1	—	1	—	—	—	—
Participant Contributions	46	3	7	6	5	3	3
Benefit Payments	(105)	(9)	(17)	(13)	(11)	(6)	(7)
Fair Value of Plan Assets as of December 31,	$ 1,980	$ 168	$ 286	$ 237	$ 203	$ 109	$ 138
Funded Status as of December 31,	$ 1,404	$ 122	$ 196	$ 172	$ 147	$ 79	$ 101

2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Change in Benefit Obligation				(in millions)			
Benefit Obligation as of January 1,	$ 850	$ 66	$ 135	$ 99	$ 86	$ 44	$ 54
Service Cost	4	—	—	1	—	—	—
Interest Cost	42	3	7	5	4	2	3
Actuarial (Gain) Loss	(192)	(15)	(31)	(25)	(21)	(10)	(12)
Special/Contractual Termination Benefits	4	—	1	—	—	—	—
Benefit Payments	(106)	(8)	(17)	(13)	(11)	(6)	(7)
Participant Contributions	45	4	7	6	5	3	3
Benefit Obligation as of December 31,	$ 647	$ 50	$ 102	$ 73	$ 63	$ 33	$ 41
Change in Fair Value of Plan Assets							
Fair Value of Plan Assets as of January 1,	$ 1,673	$ 137	$ 243	$ 205	$ 177	$ 90	$ 111
Actual Gain on Plan Assets	160	14	22	14	14	8	14
Company Contributions	4	—	1	—	—	—	—
Participant Contributions	45	4	7	6	5	3	3
Benefit Payments	(106)	(8)	(17)	(13)	(11)	(6)	(7)
Fair Value of Plan Assets as of December 31,	$ 1,776	$ 147	$ 256	$ 212	$ 185	$ 95	$ 121
Funded Status as of December 31,	$ 1,129	$ 97	$ 154	$ 139	$ 122	$ 62	$ 80

Amounts Included on the Balance Sheets Related to Funded Status

<u>Pension Plans</u>

December 31, 2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Other Noncurrent Assets - Employee Benefits and Pension Assets	$ —	$ —	$ 43	$ 67	$ 35	$ 16	$ —
Other Current Liabilities – Accrued Short-term Benefit Liability	(6)	—	—	—	—	—	—
Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(78)	(24)	—	(1)	—	(1)	(33)
Funded (Underfunded) Status	$ (84)	$ (24)	$ 43	$ 66	$ 35	$ 15	$ (33)

December 31, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Other Noncurrent Assets - Employee Benefits and Pension Assets	$ —	$ —	$ 35	$ 58	$ 30	$ 11	$ —
Other Current Liabilities – Accrued Short-term Benefit Liability	(5)	(1)	—	—	—	—	—
Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(201)	(34)	—	(1)	—	(1)	(39)
Funded (Underfunded) Status	$ (206)	$ (35)	$ 35	$ 57	$ 30	$ 10	$ (39)

<u>OPEB</u>

December 31, 2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Other Noncurrent Assets - Employee Benefits and Pension Assets	$ 1,404	$ 122	$ 208	$ 172	$ 147	$ 79	$ 101
Other Current Liabilities – Accrued Short-term Benefit Liability	(2)	—	(1)	—	—	—	—
Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	2	—	(11)	—	—	—	—
Funded Status	$ 1,404	$ 122	$ 196	$ 172	$ 147	$ 79	$ 101

December 31, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Other Noncurrent Assets - Employee Benefits and Pension Assets	$ 1,130	$ 97	$ 168	$ 139	$ 122	$ 62	$ 80
Other Current Liabilities – Accrued Short-term Benefit Liability	(2)	—	(1)	—	—	—	—
Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	1	—	(13)	—	—	—	—
Funded Status	$ 1,129	$ 97	$ 154	$ 139	$ 122	$ 62	$ 80

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

The following tables show the components of the plans included in Regulatory Assets, Deferred Income Taxes and AOCI and the items attributable to the change in these components:

Pension Plans

December 31, 2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				**(in millions)**			
Net Actuarial Loss	$ 1,094	$ 185	$ 105	$ —	$ 135	$ 49	$ 79
Recorded as							
Regulatory Assets	$ 984	$ 173	$ 104	$ 9	$ 135	$ 49	$ 79
Deferred Income Taxes	23	2	—	(1)	—	—	—
Net of Tax AOCI	87	10	1	(8)	—	—	—

December 31, 2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				**(in millions)**			
Actuarial Gain During the Year	$ (44)	$ (3)	$ (5)	$ (6)	$ (5)	$ (4)	$ (3)
Amortization of Actuarial Loss	(16)	(1)	(2)	(2)	(1)	(1)	(1)
Change for the Year Ended December 31,	$ (60)	$ (4)	$ (7)	$ (8)	$ (6)	$ (5)	$ (4)

December 31, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				**(in millions)**			
Net Actuarial Loss	$ 1,154	$ 189	$ 112	$ 8	$ 141	$ 54	$ 83
Recorded as							
Regulatory Assets	$ 1,020	$ 177	$ 110	$ 18	$ 141	$ 54	$ 83
Deferred Income Taxes	28	2	—	(2)	—	—	—
Net of Tax AOCI	106	10	2	(8)	—	—	—

December 31, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				**(in millions)**			
Actuarial Loss During the Year	$ 188	$ 24	$ 19	$ 23	$ 16	$ 12	$ 2
Amortization of Actuarial Loss	(5)	—	—	(1)	—	—	—
Amounts Recognized Due to Settlement	(93)	(10)	(12)	(9)	(7)	(5)	(9)
Change for the Year Ended December 31,	$ 90	$ 14	$ 7	$ 13	$ 9	$ 7	$ (7)

OPEB

December 31, 2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				**(in millions)**			
Net Actuarial Gain	$ (241)	$ (18)	$ (40)	$ (21)	$ (23)	$ (7)	$ (15)
Prior Service Credit	(12)	(1)	(2)	(3)	(1)	(1)	(1)
Recorded as							
Regulatory Assets	$ (195)	$ (18)	$ (15)	$ (24)	$ (24)	$ (8)	$ (9)
Deferred Income Taxes	(12)	—	(6)	—	—	—	(1)
Net of Tax AOCI	(46)	(1)	(21)	—	—	—	(6)

December 31, 2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				**(in millions)**			
Actuarial Gain During the Year	$ (199)	$ (20)	$ (30)	$ (23)	$ (18)	$ (12)	$ (15)
Amortization of Prior Service Credit	3	—	—	(1)	1	—	—
Change for the Year Ended December 31,	$ (196)	$ (20)	$ (30)	$ (24)	$ (17)	$ (12)	$ (15)

December 31, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				**(in millions)**			
Net Actuarial (Gain) Loss	$ (42)	$ 2	$ (10)	$ 2	$ (5)	$ 5	$ —
Prior Service Credit	(15)	(1)	(2)	(2)	(2)	(1)	(1)
Recorded as							
Regulatory Assets	$ (56)	$ 1	$ (2)	$ (3)	$ (7)	$ 4	$ —
Deferred Income Taxes	—	—	(2)	1	—	—	—
Net of Tax AOCI	(1)	—	(8)	2	—	—	(1)

December 31, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				**(in millions)**			
Actuarial Gain During the Year	$ (240)	$ (20)	$ (37)	$ (26)	$ (23)	$ (13)	$ (18)
Amortization of Actuarial Loss	(3)	—	—	(1)	—	—	—
Amortization of Prior Service Credit	13	1	2	2	1	1	1
Change for the Year Ended December 31,	$ (230)	$ (19)	$ (35)	$ (25)	$ (22)	$ (12)	$ (17)

Determination of Pension Expense

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

Pension and OPEB Assets

The fair value tables within Pension and OPEB Assets present the classification of assets for AEP within the fair value hierarchy. All Level 1, 2, 3 and Other amounts can be allocated to the Registrant Subsidiaries using the percentages in the table below:

	Pension Plan		OPEB	
	December 31,			
Company	**2025**	**2024**	**2025**	**2024**
AEP Texas	8.1 %	7.9 %	8.5 %	8.3 %
APCo	13.2 %	13.3 %	14.4 %	14.4 %
I&M	13.7 %	13.8 %	12.0 %	11.9 %
OPCo	10.1 %	10.4 %	10.2 %	10.4 %
PSO	5.4 %	5.5 %	5.5 %	5.4 %
SWEPCo	5.3 %	5.2 %	7.0 %	6.8 %

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2025:

Asset Class	**Level 1**	**Level 2**	**Level 3**	**Other**	**Total**	**Year End Allocation**
			(in millions)			
Equities (a):						
Domestic	$ 109	$ —	$ —	$ —	$ 109	2.9 %
International	68	—	—	—	68	1.8 %
Common Collective Trusts (b)	228	—	—	901	1,129	30.0 %
Subtotal – Equities	405	—	—	901	1,306	34.7 %
Fixed Income (a):						
United States Government and Agency Securities	—	1,060	—	—	1,060	28.2 %
Corporate Debt	—	627	—	—	627	16.7 %
Foreign Debt	—	110	—	—	110	2.9 %
State and Local Government	—	21	—	—	21	0.6 %
Other – Asset Backed	—	5	—	—	5	0.1 %
Subtotal – Fixed Income	—	1,823	—	—	1,823	48.5 %
Infrastructure (b)	—	—	—	114	114	3.0 %
Real Estate (b)	—	—	—	221	221	5.9 %
Alternative Investments (b)	—	—	—	218	218	5.8 %
Cash and Cash Equivalents (b)	—	18	—	29	47	1.3 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	30	30	0.8 %
Total	$ 405	$ 1,841	$ —	$ 1,513	$ 3,759	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2025:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 643	$ —	$ —	$ —	$ 643	32.5 %
International	241	—	—	—	241	12.2 %
Common Collective Trusts (a)	85	—	—	287	372	18.8 %
Subtotal – Equities	969	—	—	287	1,256	63.5 %
Fixed Income:						
United States Government and Agency Securities	—	265	—	—	265	13.4 %
Corporate Debt	—	141	—	—	141	7.1 %
Foreign Debt	—	26	—	—	26	1.3 %
State and Local Government	84	4	—	—	88	4.4 %
Other – Asset Backed	—	2	—	—	2	0.1 %
Subtotal – Fixed Income	84	438	—	—	522	26.3 %
Trust Owned Life Insurance:						
International Equities	—	30	—	—	30	1.5 %
United States Bonds	—	110	—	—	110	5.6 %
Subtotal – Trust Owned Life Insurance	—	140	—	—	140	7.1 %
Cash and Cash Equivalents (a)	28	—	—	—	28	1.4 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	34	34	1.7 %
Total	$ 1,081	$ 578	$ —	$ 321	$ 1,980	100.0 %

(a) Amounts in “Other” column represent investments for which fair value is measured using net asset value per-share.
(b) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2024:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 327	$ —	$ —	$ —	$ 327	8.9 %
International	290	—	—	—	290	7.9 %
Common Collective Trusts (b)	176	—	—	473	649	17.7 %
Subtotal – Equities	793	—	—	473	1,266	34.5 %
Fixed Income (a):						
United States Government and Agency Securities	(2)	866	—	—	864	23.6 %
Corporate Debt	—	719	—	—	719	19.6 %
Foreign Debt	—	136	—	—	136	3.7 %
State and Local Government	—	26	—	—	26	0.7 %
Other – Asset Backed	—	1	—	—	1	— %
Subtotal – Fixed Income	(2)	1,748	—	—	1,746	47.6 %
Infrastructure (b)	—	—	—	113	113	3.1 %
Real Estate (b)	—	—	—	228	228	6.2 %
Alternative Investments (b)	—	—	—	224	224	6.1 %
Cash and Cash Equivalents (b)	—	41	—	27	68	1.9 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	21	21	0.6 %
Total	$ 791	$ 1,789	$ —	$ 1,086	$ 3,666	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2024:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 617	$ —	$ —	$ —	$ 617	34.7 %
International	267	—	—	—	267	15.0 %
Common Collective Trusts (a)	64	—	—	130	194	10.9 %
Subtotal – Equities	948	—	—	130	1,078	60.6 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	133	133	7.5 %
United States Government and Agency Securities	(1)	158	—	—	157	8.9 %
Corporate Debt	—	132	—	—	132	7.5 %
Foreign Debt	—	27	—	—	27	1.5 %
State and Local Government	58	5	—	—	63	3.5 %
Subtotal – Fixed Income	57	322	—	133	512	28.9 %
Trust Owned Life Insurance:						
International Equities	—	23	—	—	23	1.3 %
United States Bonds	—	118	—	—	118	6.7 %
Subtotal – Trust Owned Life Insurance	—	141	—	—	141	8.0 %
Cash and Cash Equivalents (a)	28	—	—	3	31	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	14	14	0.8 %
Total	$ 1,033	$ 463	$ —	$ 280	$ 1,776	100.0 %

(a) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

Accumulated Benefit Obligation

The accumulated benefit obligation for the pension plans is as follows:

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 3,559	$ 303	$ 433	$ 418	$ 319	$ 173	$ 212
Nonqualified Pension Plans	45	2	—	1	—	1	1
Total as of December 31, 2025	$ 3,604	$ 305	$ 433	$ 419	$ 319	$ 174	$ 213

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 3,602	$ 301	$ 434	$ 422	$ 326	$ 175	$ 210
Nonqualified Pension Plans	47	2	—	1	—	1	1
Total as of December 31, 2024	$ 3,649	$ 303	$ 434	$ 423	$ 326	$ 176	$ 211

Obligations in Excess of Fair Values

The tables below show the underfunded pension plans that had obligations in excess of plan assets.

Projected Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Projected Benefit Obligation	$ 3,843	$ 327	$ —	$ 1	$ 1	$ 2	$ 233
Fair Value of Plan Assets	3,759	303	—	—	—	—	200
Underfunded Projected Benefit Obligation as of December 31, 2025	$ (84)	$ (24)	$ —	$ (1)	$ (1)	$ (2)	$ (33)

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Projected Benefit Obligation	$ 3,872	$ 323	$ 1	$ 1	$ —	$ 1	$ 228
Fair Value of Plan Assets	3,666	288	—	—	—	—	189
Underfunded Projected Benefit Obligation as of December 31, 2024	$ (206)	$ (35)	$ (1)	$ (1)	$ —	$ (1)	$ (39)

Accumulated Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Accumulated Benefit Obligation	$ 45	$ 2	$ —	$ 1	$ —	$ 1	$ 213
Fair Value of Plan Assets	—	—	—	—	—	—	200
Underfunded Accumulated Benefit Obligation as of December 31, 2025	$ (45)	$ (2)	$ —	$ (1)	$ —	$ (1)	$ (13)

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Accumulated Benefit Obligation	$ 47	$ 303	$ —	$ 1	$ —	$ 1	$ 211
Fair Value of Plan Assets	—	288	—	—	—	—	189
Underfunded Accumulated Benefit Obligation as of December 31, 2024	$ (47)	$ (15)	$ —	$ (1)	$ —	$ (1)	$ (22)

Estimated Future Benefit Payments and Contributions

The estimated pension benefit payments and contributions to the trust are at least the minimum amount required by the Employee Retirement Income Security Act plus payment of unfunded non-qualified benefits. For the qualified pension plan, additional discretionary contributions may also be made to maintain the funded status of the plan. For OPEB plans, expected payments include the payment of unfunded benefits. The following table provides the estimated contributions and payments by Registrant for 2026:

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Pension Plans	$ 83	$ 11	$ —	$ 1	$ —	$ —	$ 8
OPEB	2	—	1	—	—	—	—

The tables below reflect the total benefits expected to be paid from the plan or from the Registrants' assets. The payments include the participants' contributions to the plan for their share of the cost. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for the pension benefits and OPEB are as follows:

Pension Plans	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2026	$ 357	$ 35	$ 43	$ 42	$ 32	$ 18	$ 21
2027	352	32	42	41	32	17	21
2028	352	32	41	41	31	18	21
2029	342	31	41	38	30	16	20
2030	331	29	40	38	29	16	20
Years 2031 to 2035, in Total	1,573	127	189	182	139	76	95

OPEB Benefit Payments	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2026	$ 111	$ 9	$ 17	$ 14	$ 11	$ 6	$ 8
2027	110	9	17	14	11	6	8
2028	108	9	17	13	11	6	8
2029	105	9	17	13	10	6	7
2030	104	8	16	13	10	6	7
Years 2031 to 2035, in Total	486	39	75	59	48	27	35

OPEB Medicare Subsidy Receipts	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2026	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2027	—	—	—	—	—	—	—
2028	—	—	—	—	—	—	—
2029	—	—	—	—	—	—	—
2030	—	—	—	—	—	—	—
Years 2031 to 2035, in Total	1	—	—	—	—	—	—

Components of Net Periodic Benefit Cost (Credit)

The following tables provide the components of net periodic benefit cost (credit) by Registrant for the plans:

Pension Plans

2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 96	$ 9	$ 9	$ 13	$ 9	$ 6	$ 8
Interest Cost	211	17	25	25	19	10	13
Expected Return on Plan Assets	(281)	(23)	(38)	(39)	(28)	(15)	(15)
Amortization of Net Actuarial Loss	16	1	2	2	1	1	1
Net Periodic Benefit Cost (Credit)	42	4	(2)	1	1	2	7
Capitalized Portion	(45)	(5)	(4)	(4)	(5)	(3)	(3)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ (3)	$ (1)	$ (6)	$ (3)	$ (4)	$ (1)	$ 4

2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 101	$ 9	$ 9	$ 13	$ 9	$ 6	$ 8
Interest Cost	207	17	25	24	19	10	12
Expected Return on Plan Assets	(320)	(25)	(43)	(42)	(33)	(17)	(17)
Amortization of Net Actuarial Loss	5	—	—	1	—	—	—
Settlements (a)	93	10	12	9	7	5	9
Net Periodic Benefit Cost	86	11	3	5	2	4	12
Capitalized Portion	(47)	(5)	(4)	(4)	(5)	(3)	(3)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 39	$ 6	$ (1)	$ 1	$ (3)	$ 1	$ 9

(a) AEP will seek recovery for the portion of pension settlement costs related to regulated operations. These costs were deferred as a regulatory asset for AEP, AEP Texas, APCo and PSO in the fourth quarter of 2024.

2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 94	$ 8	$ 9	$ 12	$ 8	$ 5	$ 8
Interest Cost	219	18	26	25	20	11	14
Expected Return on Plan Assets	(339)	(28)	(44)	(44)	(34)	(18)	(20)
Amortization of Net Actuarial Loss	2	—	—	—	—	—	—
Net Periodic Benefit Cost (Credit)	(24)	(2)	(9)	(7)	(6)	(2)	2
Capitalized Portion	(44)	(4)	(4)	(4)	(5)	(3)	(3)
Net Periodic Benefit Credit Recognized in Expense	$ (68)	$ (6)	$ (13)	$ (11)	$ (11)	$ (5)	$ (1)

OPEB

2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 4	$ —	$ 1	$ —	$ —	$ —	$ —
Interest Cost	34	3	5	4	3	2	2
Expected Return on Plan Assets	(113)	(9)	(17)	(13)	(11)	(6)	(8)
Amortization of Prior Service Credit	(3)	—	—	1	(1)	—	—
Net Periodic Benefit Credit	(78)	(6)	(11)	(8)	(9)	(4)	(6)
Capitalized Portion	(2)	—	—	—	—	—	—
Net Periodic Benefit Credit Recognized in Expense	$ (80)	$ (6)	$ (11)	$ (8)	$ (9)	$ (4)	$ (6)

2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 4	$ —	$ —	$ 1	$ —	$ —	$ —
Interest Cost	42	3	7	5	4	2	3
Expected Return on Plan Assets	(111)	(8)	(16)	(14)	(11)	(5)	(7)
Amortization of Prior Service Credit	(13)	(1)	(2)	(2)	(1)	(1)	(1)
Amortization of Net Actuarial Loss	3	—	—	1	—	—	—
Special/Contractual Termination Benefits	4	—	1	—	—	—	—
Net Periodic Benefit Credit	(71)	(6)	(10)	(9)	(8)	(4)	(5)
Capitalized Portion	(2)	—	—	—	—	—	—
Net Periodic Benefit Credit Recognized in Expense	$ (73)	$ (6)	$ (10)	$ (9)	$ (8)	$ (4)	$ (5)

2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 5	$ —	$ 1	$ 1	$ —	$ —	$ —
Interest Cost	46	4	7	5	4	2	3
Expected Return on Plan Assets	(110)	(9)	(16)	(13)	(12)	(6)	(7)
Amortization of Prior Service Credit	(63)	(5)	(9)	(9)	(6)	(4)	(5)
Amortization of Net Actuarial Loss	15	1	2	2	2	1	1
Net Periodic Benefit Credit	(107)	(9)	(15)	(14)	(12)	(7)	(8)
Capitalized Portion	(2)	—	—	—	—	—	—
Net Periodic Benefit Credit Recognized in Expense	$ (109)	$ (9)	$ (15)	$ (14)	$ (12)	$ (7)	$ (8)

American Electric Power System Retirement Savings Plan

AEPSC sponsors the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all AEP subsidiary employees who are not covered by a retirement savings plan of the UMWA. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the IRC and provides for company matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions.

The following table provides the cost for matching contributions to the retirement savings plans by Registrant:

Year Ended December 31,	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2025	$ 84	$ 7	$ 8	$ 11	$ 8	$ 6	$ 6
2024	82	7	8	11	8	5	7
2023	88	7	8	11	8	5	7

UMWA Benefits

Health and Welfare Benefits (Applies to AEP and APCo)

AEP provides health and welfare benefits negotiated with the UMWA for certain unionized employees, retirees and their survivors who meet eligibility requirements. APCo also provides the same UMWA health and welfare benefits for certain unionized mining retirees and their survivors who meet eligibility requirements. AEP administers the health and welfare benefits. Benefits are paid for APCo from its general assets and for AEP from a trust and its general assets.

Multiemployer Pension Benefits (Applies to AEP)

UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-1050282, Plan Number 002), a multiemployer plan. The UMWA pension benefits are administered by a board of trustees appointed in equal numbers by the UMWA and the Bituminous Coal Operators' Association (BCOA), an industry bargaining association. AEP makes contributions to the United Mine Workers of America 1974 Pension Plan based on provisions in its labor agreement and the plan documents. The UMWA pension plan is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. A withdrawing employer may be subject to a withdrawal liability, which is calculated based upon that employer's share of the plan's unfunded benefit obligations. If an employer fails to make required contributions or if its payments in connection with its withdrawal liability fall short of satisfying its share of the plan's unfunded benefit obligations, the remaining employers may be allocated a greater share of the remaining unfunded plan obligations. Under the Pension Protection Act of 2006 (PPA), the UMWA pension plan is in Critical Status for the plan year beginning July 1, 2025 and was in Critical Status for the plan year beginning July 1, 2024. As required under the PPA, the Plan adopted a Rehabilitation Plan in 2015. The Rehabilitation Plan has been updated annually, most recently April 25, 2025.

AEP affiliates contributed $471 thousand, $379 thousand and $396 thousand to the United Mine Workers of America 1974 Pension Plan for the years ended December 31, 2025, 2024 and 2023, respectively. The contributions did not include surcharges. An AEP affiliate, Cook Coal Terminal (CCT), was listed in the plan's 2023 Form 5500 as providing more than 5 percent of the total contributions for the plan year ending June 30, 2024. The plan's 2023 Form 5500 was filed in the second quarter of 2025.

Under the terms of the UMWA pension plan, contributions will be required to continue beyond the January 25, 2027 expiration of the current collective bargaining agreement between the CCT facility and the UMWA, whether or not the term of that agreement is extended or a subsequent agreement is entered, so long as both the UMWA pension plan remains in effect and an AEP affiliate continues to operate the facility covered by the current collective bargaining agreement. The contribution rate applicable would be determined in accordance with the terms of the UMWA pension plan by reference to the National Bituminous Coal Wage Agreement, subject to periodic revisions, between the UMWA and the BCOA. If the UMWA pension plan would terminate or an AEP affiliate would cease operation of the facility without arranging for a successor operator to assume its liability, the withdrawal liability obligation would be triggered.

AEP records a UMWA pension withdrawal liability on the balance sheet that is re-measured annually and is the estimated value of the company's anticipated contributions toward its proportionate share of the plan's unfunded vested liabilities. As of December 31, 2025 and 2024, the liability balance was $12 million and $12 million, respectively. AEP recovers the estimated value of its UMWA pension withdrawal liability through fuel clauses in certain regulated jurisdictions. AEP records a regulatory asset on the balance sheets when the UMWA pension withdrawal liability exceeds the cumulative billings collected and a regulatory liability on the balance sheets when the cumulative billings collected exceed the withdrawal liability. If any portion of the UMWA pension withdrawal liability is not recoverable, it could reduce future net income and cash flows and impact financial condition.

9. 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 present AEP's reportable segment income statement information for the years ended December 31, 2025, 2024 and 2023 and reportable segment balance sheet information as of December 31, 2025 and 2024. The significant expenses disclosed below align with the segment-level information that is regularly provided to the CODM.

2025	VIU	T&D	AEPTHCo	G&M	Total Reportable Segments	Corporate and Other (a)	Reconciling Adjustments	Consolidated
					(in millions)			
Revenues from:								
External Customers	$ 12,556	$ 6,097	$ 493	$ 2,697	$ 21,843	$ 33	$ —	$ 21,876
Other Operating Segments	263	50	1,884	65	2,262	111	(2,373) (b)	—
Total Revenues	12,819	6,147	2,377	2,762	24,105	144	(2,373)	21,876
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	4,056	943	—	2,325	7,324	—	(293)	7,031
Other Operation and Maintenance	3,884	2,318	194	83	6,479	74	(2,104)	4,449
Asset Impairments and Other Related Charges	35	31	—	—	66	—	—	66
Depreciation and Amortization	2,076	821	487	16	3,400	(20)	—	3,380
Taxes Other Than Income Taxes	532	744	328	2	1,606	1	24	1,631
Allowance for Equity Funds Used During Construction	74	77	94	—	245	—	—	245
Interest Expense	856	424	241	8	1,529	592	(95)	2,026
Income Tax Expense (Benefit)	(60)	173	42	95	250	(121)	—	129
Equity Earnings of Unconsolidated Subsidiaries	1	2	87	—	90	11	—	101
Other Segment Items (c)	(90)	(44)	105	(54)	(83)	(82)	95	(70)
Earnings (Loss) Attributable to AEP Common Shareholders	$ 1,605	$ 816	$ 1,161	$ 287	$ 3,869	$ (289)	$ —	$ 3,580
Gross Property Additions	$ 7,333	$ 2,978	$ 1,615	$ 12	$ 11,938	$ 38	$ (70)	$ 11,906
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

2024	VIU	T&D	AEPTHCo	G&M	Total Reportable Segments	Corporate and Other (a)	Reconciling Adjustments	Consolidated
					(in millions)			
Revenues from:								
External Customers	$ 11,414	$ 5,880	$ 425	$ 1,945	$ 19,664	$ 57	$ —	$ 19,721
Other Operating Segments	183	28	1,526	100	1,837	126	(1,963) (b)	—
Total Revenues	11,597	5,908	1,951	2,045	21,501	183	(1,963)	19,721
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	3,796	909	—	1,542	6,247	—	(311)	5,936
Other Operation and Maintenance	3,528	2,166	163	130	5,987	137	(1,672)	4,452
Asset Impairments and Other Related Charges	14	53	—	76	143	—	—	143
Depreciation and Amortization	1,971	880	440	21	3,312	(22)	—	3,290
Taxes Other Than Income Taxes	535	724	315	2	1,576	—	20	1,596
Allowance for Equity Funds Used During Construction	52	69	90	—	211	—	—	211
Interest Expense	724	406	222	17	1,369	613	(119)	1,863
Income Tax Expense (Benefit)	(282)	155	215	26	114	(153)	—	(39)
Equity Earnings (Loss) of Unconsolidated Subsidiaries	1	(1)	99	1	100	(6)	—	94
Other Segment Items (c)	(89)	(43)	(5)	(57)	(194)	(107)	119	(182)
Earnings (Loss) Attributable to AEP Common Shareholders	$ 1,453	$ 726	$ 790	$ 289	$ 3,258	$ (291)	$ —	$ 2,967
Gross Property Additions	$ 3,644	$ 2,344	$ 1,572	$ 35	$ 7,595	$ 467	$ (32)	$ 8,030
Total Assets	$ 54,997	$ 26,864	$ 18,012	$ 1,634	$ 101,507	$ 5,551 (d)	$ (3,980) (e)	$ 103,078
Investments in Equity Method Investees	$ 9	$ 2	$ 996	$ —	$ 1,007	$ 49	$ —	$ 1,056

2023	VIU	T&D	AEPTHCo	G&M	Total Reportable Segments	Corporate and Other (a)	Reconciling Adjustments	Consolidated
					(in millions)			
Revenues from:								
External Customers	$ 11,304	$ 5,677	$ 397	$ 1,543	$ 18,921	$ 61	$ —	$ 18,982
Other Operating Segments	146	36	1,332	89	1,603	107	(1,710) (b)	—
Total Revenues	11,450	5,713	1,729	1,632	20,524	168	(1,710)	18,982
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	4,150	1,215	—	1,488	6,853	—	(275)	6,578
Other Operation and Maintenance	3,211	1,948	142	133	5,434	103	(1,450)	4,087
Asset Impairments and Other Related Charges	86	—	—	—	86	—	—	86
Loss on the Sale of the Competitive Contracted Renewables Portfolio	—	—	—	93	93	—	—	93
Depreciation and Amortization	1,876	785	403	43	3,107	(17)	—	3,090
Taxes Other Than Income Taxes	513	668	290	6	1,477	—	15	1,492
Allowance for Equity Funds Used During Construction	46	46	83	—	175	—	—	175
Interest Expense	765	364	203	76	1,408	594	(195)	1,807
Income Tax Expense (Benefit)	(45)	140	166	(123)	138	(83)	—	55
Equity Earnings (Loss) of Unconsolidated Subsidiaries	1	—	83	(17)	67	(8)	—	59
Other Segment Items (c)	(149)	(60)	(12)	(75)	(296)	(179)	195	(280)
Earnings (Loss) Attributable to AEP Common Shareholders	$ 1,090	$ 699	$ 703	$ (26)	$ 2,466	$ (258)	$ —	$ 2,208
Gross Property Additions	$ 3,487	$ 2,467	$ 1,529	$ 13	$ 7,496	$ 36	$ 1	$ 7,533
Investments in Equity Method Investees	$ 10	$ 3	$ 906	$ 101	$ 1,020	$ 54	$ —	$ 1,074

(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 Period Benefit Cost and Net Income (Loss) Attributable to Noncontrolling Interests.
(d) Includes elimination of AEP Parent's investments in wholly-owned subsidiary companies.
(e) Reconciling Adjustments for Total Assets primarily include elimination of intercompany advances to affiliates and intercompany accounts receivable.

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

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business for APCo, I&M, PSO and SWEPCo, and an integrated electricity transmission and distribution business for AEP Texas and OPCo. Other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results. The CODM of each Registrant Subsidiary is the AEP President and CEO, who makes operating decisions, allocates resources to and assesses performance based on these reportable segments. The CODM uses net income (loss) that is reported on the Registrant Subsidiaries' statements of income as a measure of segment profit or loss in making these decisions. Net income (loss) includes intercompany revenues and expenses that are eliminated on the consolidated financial statements. The expenses disclosed on the Registrant Subsidiaries' statements of income align with the segment-level significant expenses that are regularly provided to the CODM. Total Assets is reported on the consolidated financial statements. Gross Property Additions for the Registrant Subsidiaries is represented by the sum of Construction Expenditures and Acquisition of Assets on the consolidated financial statements. See Registrant Subsidiaries statements of income, balance sheets and cash flows for details.

AEPTCo's Reportable Segments

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

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

The tables below present AEPTCo's reportable segment income statement information for the years ended December 31, 2025, 2024 and 2023 and reportable segment balance sheet information as of December 31, 2025 and 2024. The significant expenses disclosed below align with the segment-level information that is regularly provided to the CODM.

2025	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 450	$ —	$ —	$ 450
Sales to AEP Affiliates	1,869	—	—	1,869
Total Revenues	2,319	—	—	2,319
Other Operation and Maintenance	185	—	—	185
Depreciation and Amortization	478	—	—	478
Taxes Other Than Income Taxes	321	—	—	321
Interest Income	3	308	(306) (a)	5
Allowance for Equity Funds Used During Construction	93	—	—	93
Interest Expense	283	257	(306) (a)	234
Income Tax Expense	4	11	—	15
Other Segment Items (b)	—	109	—	109
Earnings Attributable to AEPTCo Common Shareholders	$ 1,144	$ (69) (c)	$ —	$ 1,075
Gross Property Additions	$ 1,579	$ —	$ —	$ 1,579
Total Assets	$ 17,983	$ 6,766 (d)	$ (6,750) (e)	$ 17,999

2024	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 379	$ —	$ —	$ 379
Sales to AEP Affiliates	1,512	—	—	1,512
Total Revenues	1,891	—	—	1,891
Other Operation and Maintenance	156	2	—	158
Depreciation and Amortization	431	—	—	431
Taxes Other Than Income Taxes	309	—	—	309
Interest Income	8	241	(239) (a)	10
Allowance for Equity Funds Used During Construction	89	—	—	89
Interest Expense	214	239	(239) (a)	214
Income Tax Expense	190	—	—	190
Earnings Attributable to AEPTCo Common Shareholders	$ 688	$ — (c)	$ —	$ 688
Gross Property Additions	$ 1,482	$ —	$ —	$ 1,482
Total Assets	$ 16,888	$ 8,670 (d)	$ (9,188) (e)	$ 16,370

2023	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 354	$ —	$ —	$ 354
Sales to AEP Affiliates	1,317	—	—	1,317
Total Revenues	1,671	—	—	1,671
Other Operation and Maintenance	129	—	—	129
Depreciation and Amortization	394	—	—	394
Taxes Other Than Income Taxes	283	—	—	283
Interest Income	4	218	(214) (a)	8
Allowance for Equity Funds Used During Construction	83	—	—	83
Interest Expense	194	215	(214) (a)	195
Income Tax Expense	145	2	—	147
Earnings Attributable to AEPTCo Common Shareholders	$ 613	$ 1 (c)	$ —	$ 614
Gross Property Additions	$ 1,503	$ —	$ —	$ 1,503

(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.

10. 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

Primary Risk Exposure	December 31, 2025							December 31, 2024						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)													
Commodity:														
Power (MWhs)	327	—	23	8	2	8	6	282	—	24	8	2	5	5
Natural Gas (MMBtus)	166	—	48	—	—	44	26	153	—	42	—	—	46	15
Heating Oil and Gasoline (Gallons)	8	2	1	2	1	1	1	8	2	1	2	1	1	1
Interest Rate (USD)	$ 40	$ —	$ —	$ —	$ —	$ —	$ —	$ 59	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt (USD)	$ 500	$ —	$ —	$ —	$ —	$ —	$ —	$ 950	$ —	$ —	$ —	$ —	$ —	$ —

Fair Value Hedging Strategies (Applies to AEP)

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

Cash Flow Hedging Strategies

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

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

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

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

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

According to the accounting guidance for "Derivatives and Hedging," the Registrants reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrants are required to post or receive cash collateral based on third-party contractual agreements and risk profiles. AEP netted cash collateral received from third-parties against short-term and long-term risk management assets in the amounts of $83 million and $87 million as of December 31, 2025 and 2024, respectively. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets for the Registrant Subsidiaries as of December 31, 2025 and 2024. 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 December 31, 2025 and 2024.

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

The following tables represent the gross fair value of the Registrants' derivative activity on the balance sheets. The derivative instruments are disclosed as gross. They are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging." Unless shown as a separate line on the balance sheets due to materiality, Current Risk Management Assets are included in Prepayments and Other Current Assets, Long-term Risk Management Assets are included in Deferred Charges and Other Noncurrent Assets, Current Risk Management Liabilities are included in Other Current Liabilities and Long-term Risk Management Liabilities are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

	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

	December 31, 2024						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Assets:				(in millions)			
Current Risk Management Assets							
Risk Management Contracts - Commodity	$ 425	$ —	$ 40	$ 29	$ —	$ 22	$ 19
Hedging Contracts - Commodity	54	—	—	—	—	—	—
Total Current Risk Management Assets	479	—	40	29	—	22	19
Long-term Risk Management Assets							
Risk Management Contracts - Commodity	475	—	2	1	—	2	—
Hedging Contracts - Commodity	85	—	—	—	—	—	—
Total Long-term Risk Management Assets	560	—	2	1	—	2	—
Total Assets	$ 1,039	$ —	$ 42	$ 30	$ —	$ 24	$ 19
Liabilities:							
Current Risk Management Liabilities							
Risk Management Contracts - Commodity	$ 304	$ —	$ 7	$ 11	$ 8	$ 8	$ 3
Hedging Contracts - Commodity	11	—	—	—	—	—	—
Hedging Contracts - Interest Rate	36	—	—	—	—	—	—
Total Current Risk Management Liabilities	351	—	7	11	8	8	3
Long-term Risk Management Liabilities							
Risk Management Contracts - Commodity	391	—	—	2	40	—	—
Hedging Contracts - Commodity	3	—	—	—	—	—	—
Hedging Contracts - Interest Rate	35	—	—	—	—	—	—
Total Long-term Risk Management Liabilities	429	—	—	2	40	—	—
Total Liabilities	$ 780	$ —	$ 7	$ 13	$ 48	$ 8	$ 3
Total MTM Derivative Contract Net Assets (Liabilities) Recognized	$ 259	$ —	$ 35	$ 17	$ (48)	$ 16	$ 16

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.

	December 31, 2025						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Assets:							
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

	December 31, 2024						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Assets:							
Current Risk Management Assets							
Gross Amounts Recognized	$ 479	$ —	$ 40	$ 29	$ —	$ 22	$ 19
Gross Amounts Offset	(269)	—	(4)	(11)	—	(1)	(1)
Net Amounts Presented	210	—	36	18	—	21	18
Long-term Risk Management Assets							
Gross Amounts Recognized	560	—	2	1	—	2	—
Gross Amounts Offset	(271)	—	(1)	(1)	—	(1)	—
Net Amounts Presented	289	—	1	—	—	1	—
Total Assets	$ 499	$ —	$ 37	$ 18	$ —	$ 22	$ 18
Liabilities:							
Current Risk Management Liabilities							
Gross Amounts Recognized	$ 351	$ —	$ 7	$ 11	$ 8	$ 8	$ 3
Gross Amounts Offset	(251)	—	(5)	(11)	(1)	(2)	(1)
Net Amounts Presented	100	—	2	—	7	6	2
Long-term Risk Management Liabilities							
Gross Amounts Recognized	429	—	—	2	40	—	—
Gross Amounts Offset	(205)	—	—	(2)	—	—	—
Net Amounts Presented	224	—	—	—	40	—	—
Total Liabilities	$ 324	$ —	$ 2	$ —	$ 47	$ 6	$ 2
Total MTM Derivative Contract Net Assets (Liabilities)	$ 175	$ —	$ 35	$ 18	$ (47)	$ 16	$ 16

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

Amount of Gain (Loss) Recognized on Risk Management Contracts

	Year Ended December 31, 2025						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Vertically Integrated Utilities Revenues	$ (9)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	102	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	—	(10)	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	7	—	7	—	—	—	—
Regulatory Assets (a)	(16)	—	—	—	15	(25)	(6)
Regulatory Liabilities (a)	394	—	124	28	1	116	100
Total Gain on Risk Management Contracts	$ 478	$ —	$ 131	$ 18	$ 16	$ 91	$ 94

	Year Ended December 31, 2024						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Vertically Integrated Utilities Revenues	$ (24)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(172)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	—	(24)	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	3	—	3	—	—	—	—
Regulatory Assets (a)	73	—	22	3	(2)	26	14
Regulatory Liabilities (a)	271	—	53	13	—	94	95
Total Gain (Loss) on Risk Management Contracts	$ 151	$ —	$ 78	$ (8)	$ (2)	$ 120	$ 109

	Year Ended December 31, 2023						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Vertically Integrated Utilities Revenues	$ 25	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(424)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	—	24	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	3	—	2	—	—	—	—
Other Operation	(1)	—	—	—	—	—	—
Maintenance	(1)	(1)	—	—	—	—	—
Regulatory Assets (a)	(95)	—	(22)	(3)	(14)	(30)	(16)
Regulatory Liabilities (a)	170	—	1	8	—	89	71
Total Gain (Loss) on Risk Management Contracts	$ (323)	$ (1)	$ (19)	$ 29	$ (14)	$ 59	$ 55

(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**	
	December 31, 2025	**December 31, 2024**	**December 31, 2025**	**December 31, 2024**
		(in millions)		
Long-term Debt (a) (b)	$ (484)	$ (899)	$ 15	$ 49

(a) Amounts included within Noncurrent Liabilities line item Long-term Debt on the balance sheet.
(b) Amounts include $(14) million and $(22) million as of December 31, 2025 and 2024, respectively, for the fair value hedge adjustment of hedged debt obligations for which hedge accounting has been discontinued.

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

	Years Ended December 31,		
	2025	**2024**	**2023**
		(in millions)	
Gain (Loss) on Interest Rate Contracts:			
Fair Value Hedging Instruments (a)	$ 42	$ 27	$ 29
Fair Value Portion of Long-term Debt (a)	(42)	(27)	(29)

(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 years ended 2025, 2024 and 2023, AEP applied cash flow hedging to outstanding power derivatives and the Registrant Subsidiaries did not.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the year ended 2025, the Registrants did not apply cash flow hedging to outstanding interest rate derivatives. During the year ended 2024, AEP, AEP Texas and PSO applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not. During the year ended 2023, AEP, AEP Texas, I&M, PSO and SWEPCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not.

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

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

Impact of Cash Flow Hedges on the Registrants' Balance Sheets

	December 31, 2025				December 31, 2024			
	AOCI Gain (Loss) Net of Tax		Portion Expected to be Reclassed to Net Income During the Next Twelve Months		AOCI Gain (Loss) Net of Tax		Portion Expected to be Reclassed to Net Income During the Next Twelve Months	
	Commodity	Interest Rate	Commodity	Interest Rate	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)							
AEP	$ 78	$ (1)	$ 31	$ —	$ 99	$ 3	$ 34	$ 3
AEP Texas	—	6	—	1	—	6	—	1
APCo	—	4	—	1	—	5	—	1
I&M	—	(5)	—	—	—	(5)	—	—
PSO	—	2	—	—	—	4	—	—
SWEPCo	—	1	—	—	—	1	—	—

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

Cross-Acceleration Triggers (Applies to AEP)

Certain interest rate derivative contracts contain cross-acceleration provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-acceleration provisions could be triggered if there was a non-performance event by the Registrants under any of their outstanding debt of at least $50 million and the lender on that debt has accelerated the entire repayment obligation. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-acceleration provisions in contracts. AEP had derivative contracts with cross-acceleration provisions in a net liability position of $30 million and $72 million and no cash collateral posted as of December 31, 2025 and 2024, respectively. If a cross-acceleration provision would have been triggered, settlement at fair value would have been required. The Registrant Subsidiaries' had no derivative contracts with cross-acceleration provisions outstanding as of December 31, 2025 and 2024.

Cross-Default Triggers (Applies to AEP, APCo, PSO and SWEPCo)

In addition, a majority of non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third-party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. AEP had derivative contracts with cross-default provisions in a net liability position of $183 million and $164 million and no cash collateral posted as of December 31, 2025 and 2024, respectively, after considering contractual netting arrangements. 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. APCo, PSO and SWEPCo had derivative contracts with cross-default provisions in a net liability position of $1 million, $4 million and $2 million, respectively, and no cash collateral posted as of December 31, 2024. If a cross-default provision would have been triggered, settlement at fair value would have been required. The other Registrant Subsidiaries had no derivative contracts with cross-default provisions in a net liability position as of December 31, 2025 and 2024.

11. FAIR VALUE MEASUREMENTS

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

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:

	December 31,			
	2025		2024	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
	(in millions)			
AEP	$ 47,322	$ 44,930	$ 42,643	$ 38,965
AEP Texas	7,016	6,586	6,442	5,831
AEPTCo	6,599	5,812	5,768	4,853
APCo	6,259	6,147	5,661	5,346
I&M	3,561	3,288	3,494	3,154
OPCo	3,718	3,331	3,716	3,203
PSO	3,526	3,349	2,856	2,562
SWEPCo	4,974	4,603	3,981	3,432

Fair Value Measurements of Other Temporary Investments (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. See "Other Temporary Investments" section of Note 1 for additional information.

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

	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

	December 31, 2024			
Other Temporary Investments and Restricted Cash	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
		(in millions)		
Restricted Cash (a)	$ 43	$ —	$ —	$ 43
Other Cash Deposits	13	—	—	13
Fixed Income Securities – Mutual Funds (b)	167	—	(5)	162
Equity Securities – Mutual Funds	13	27	—	40
Total Other Temporary Investments and Restricted Cash	$ 236	$ 27	$ (5)	$ 258

(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:

	Years Ended December 31,		
	2025	**2024**	**2023**
		(in millions)	
Proceeds from Investment Sales	$ 26	$ 27	$ 7
Purchases of Investments	22	21	19
Gross Realized Gains on Investment Sales	4	6	1
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)

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF are recorded at fair value. See "Nuclear Trust Funds" section of Note 1 for additional information.

The following is a summary of nuclear trust fund investments:

	December 31,							
	2025				2024			
	Fair Value	Gross Unrealized Gains	Gross Unrealized Losses	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Gross Unrealized Losses	Other-Than-Temporary Impairments
	(in millions)							
Cash and Cash Equivalents	$ 29	$ —	$ —	$ —	$ 24	$ —	$ —	$ —
Fixed Income Securities:								
United States Government	1,351	22	(1)	(15)	1,323	8	(5)	(20)
Corporate Debt	376	6	(7)	(6)	210	1	(10)	(6)
Subtotal Fixed Income Securities	1,727	28	(8)	(21)	1,533	9	(15)	(26)
Equity Securities - Domestic	3,160	2,621	(1)	—	2,838	2,289	—	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 4,916	$ 2,649	$ (9)	$ (21)	$ 4,395	$ 2,298	$ (15)	$ (26)

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

	Years Ended December 31,		
	2025	2024	2023
	(in millions)		
Proceeds from Investment Sales	$ 2,909	$ 2,851	$ 2,788
Purchases of Investments	2,959	2,902	2,845
Gross Realized Gains on Investment Sales	120	126	99
Gross Realized Losses on Investment Sales	5	12	27

The base cost of fixed income securities was $1.7 billion and $1.5 billion as of December 31, 2025 and 2024, respectively. The base cost of equity securities was $540 million and $549 million as of December 31, 2025 and 2024, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2025 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 402
After 1 year through 5 years	709
After 5 years through 10 years	223
After 10 years	393
Total	$ 1,727

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

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

	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) (d)	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) (d)	$ 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

Assets:	December 31, 2024				
	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 43	$ —	$ —	$ —	$ 43
Other Cash Deposits (a)	—	—	—	13	13
Fixed Income Securities – Mutual Funds	162	—	—	—	162
Equity Securities – Mutual Funds (b)	40	—	—	—	40
Total Other Temporary Investments and Restricted Cash	245	—	—	13	258
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	3	597	292	(518)	374
Cash Flow Hedges:					
Commodity Hedges (c)	—	116	22	(13)	125
Total Risk Management Assets	3	713	314	(531)	499
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	10	—	—	14	24
Fixed Income Securities:					
United States Government	—	1,323	—	—	1,323
Corporate Debt	—	210	—	—	210
Subtotal Fixed Income Securities	—	1,533	—	—	1,533
Equity Securities – Domestic (b)	2,838	—	—	—	2,838
Total Spent Nuclear Fuel and Decommissioning Trusts	2,848	1,533	—	14	4,395
Total Assets	$ 3,096	$ 2,246	$ 314	$ (504)	$ 5,152
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 4	$ 534	$ 148	$ (434)	$ 252
Cash Flow Hedges:					
Commodity Hedges (c)	—	13	—	(13)	—
Fair Value Hedges	—	72	—	—	72
Total Risk Management Liabilities	$ 4	$ 619	$ 148	$ (447)	$ 324

AEP Texas

Assets:	December 31, 2025 Level 1	Level 2	Level 3 (in millions)	Other	Total
Restricted Cash for Securitized Funding	$ 14	$ —	$ —	$ —	$ 14

Assets:	December 31, 2024 Level 1	Level 2	Level 3 (in millions)	Other	Total
Restricted Cash for Securitized Funding	$ 24	$ —	$ —	$ —	$ 24

APCo

Assets:	December 31, 2025 Level 1	Level 2	Level 3 (in millions)	Other	Total
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

Assets:	December 31, 2024 Level 1	Level 2	Level 3 (in millions)	Other	Total
Restricted Cash for Securitized Funding	$ 16	$ —	$ —	$ —	$ 16
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	7	35	(5)	37
Total Assets	$ 16	$ 7	$ 35	$ (5)	$ 53
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 7	$ —	$ (5)	$ 2

I&M

	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)	$ —

	December 31, 2024				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 19	$ 7	$ (8)	$ 18
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	10	—	—	14	24
Fixed Income Securities:					
United States Government	—	1,323	—	—	1,323
Corporate Debt	—	210	—	—	210
Subtotal Fixed Income Securities	—	1,533	—	—	1,533
Equity Securities - Domestic (b)	2,838	—	—	—	2,838
Total Spent Nuclear Fuel and Decommissioning Trusts	2,848	1,533	—	14	4,395
Total Assets	$ 2,848	$ 1,552	$ 7	$ 6	$ 4,413
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 9	$ 1	$ (10)	$ —

OPCo

	December 31, 2025				
	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ —	$ 33	$ —	$ 33

	December 31, 2024				
	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ —	$ 47	$ —	$ 47

PSO

	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

	December 31, 2024				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 3	$ 21	$ (2)	$ 22
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 7	$ 1	$ (2)	$ 6

SWEPCo

	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

	December 31, 2024				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 3	$ —	$ —	$ —	$ 3
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	1	18	(1)	18
Total Assets	$ 3	$ 1	$ 18	$ (1)	$ 21
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 2	$ 1	$ (1)	$ 2

(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 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 energy contracts.

(e) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.

(f) The December 31, 2024 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 1 matures $(1) million in 2025; Level 2 matures $(16) million in 2025, $(43) million in periods 2026-2028 and $4 million in periods 2029-2030; Level 3 matures $106 million in 2025, $45 million in periods 2026-2028, $9 million in periods 2029-2030 and $(16) million in periods 2031-2034. Risk management commodity contracts are substantially comprised of energy 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:

Year Ended December 31, 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)	157	50	13	—	38	43
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	19	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	16	—	—	—	—	—
Settlements	(286)	(85)	(19)	7	(58)	(59)
Transfers into Level 3 (d) (e)	1	—	—	—	—	—
Transfers out of Level 3 (e)	(2)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	188	81	9	7	41	34
Balance as of December 31, 2025	$ 259	$ 81	$ 9	$ (33)	$ 41	$ 35

Year Ended December 31, 2024	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2023	$ 139	$ 22	$ 3	$ (51)	$ 19	$ 11
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	90	24	7	(1)	26	24
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	15	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	4	—	—	—	—	—
Settlements	(168)	(46)	(10)	8	(45)	(36)
Transfers into Level 3 (d) (e)	7	—	—	—	—	—
Transfers out of Level 3 (e)	(6)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	85	35	6	(3)	20	18
Balance as of December 31, 2024	$ 166	$ 35	$ 6	$ (47)	$ 20	$ 17

Year Ended December 31, 2023	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2022	$ 160	$ 69	$ 5	$ (40)	$ 24	$ 14
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	52	(12)	4	(4)	30	20
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	71	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(17)	—	—	—	—	—
Settlements	(172)	(57)	(9)	6	(53)	(34)
Transfers into Level 3 (d) (e)	(6)	—	—	—	—	—
Transfers out of Level 3 (e)	4	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	47	22	3	(13)	18	11
Balance as of December 31, 2023	$ 139	$ 22	$ 3	$ (51)	$ 19	$ 11

(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
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)

December 31, 2024

Company	Type of Input	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Input/Range Low	Input/Range High	Input/Range Weighted Average (b)
		(in millions)						
AEP	Energy Contracts	$ 221	$ 145	Discounted Cash Flow	Forward Market Price	$ 2.75	$ 149.30	$ 49.34
AEP	FTRs	93	3	Discounted Cash Flow	Forward Market Price	(29.48)	19.70	0.24
APCo	FTRs	35	—	Discounted Cash Flow	Forward Market Price	(0.25)	9.32	1.56
I&M	FTRs	7	1	Discounted Cash Flow	Forward Market Price	(4.07)	9.32	1.34
OPCo	Energy Contracts	—	47	Discounted Cash Flow	Forward Market Price	14.53	72.40	42.44
PSO	FTRs	21	1	Discounted Cash Flow	Forward Market Price	(29.48)	10.54	(3.88)
SWEPCo	FTRs	18	1	Discounted Cash Flow	Forward Market Price	(29.48)	10.54	(3.88)

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

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

Uncertainty of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

12. INCOME TAXES

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

Income Tax Expense (Benefit)

The details of the Registrants' Income Tax Expense (Benefit) as reported are as follows:

Year Ended December 31, 2025	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (209)	$ 27	$ 148	$ 42	$ (3)	$ 27	$ (221)	$ (180)
Deferred	298	70	(173)	43	(14)	42	149	89
Total Federal	89	97	(25)	85	(17)	69	(72)	(91)
State and Local:								
Current	28	4	18	2	19	(2)	—	3
Deferred	12	—	22	(1)	(1)	5	2	(7)
Total State and Local	40	4	40	1	18	3	2	(4)
Income Tax Expense (Benefit)	$ 129	$ 101	$ 15	$ 86	$ 1	$ 72	$ (70)	$ (95)

Year Ended December 31, 2024	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (3)	$ 22	$ 75	$ 80	$ 17	$ 42	$ (119)	$ (112)
Deferred	(58)	77	89	(18)	(119)	(3)	20	(86)
Total Federal	(61)	99	164	62	(102)	39	(99)	(198)
State and Local:								
Current	(5)	3	6	13	7	3	—	2
Deferred	27	—	20	—	—	10	(1)	12
Total State and Local	22	3	26	13	7	13	(1)	14
Income Tax Expense (Benefit)	$ (39)	$ 102	$ 190	$ 75	$ (95)	$ 52	$ (100)	$ (184)

Year Ended December 31, 2023	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (117)	$ 20	$ 94	$ 62	$ 94	$ 46	$ (61)	$ (88)
Deferred	116	63	52	(60)	(57)	3	3	60
Total Federal	(1)	83	146	2	37	49	(58)	(28)
State and Local:								
Current	69	3	9	6	21	—	—	1
Deferred	(13)	—	(8)	6	1	5	4	(6)
Total State and Local	56	3	1	12	22	5	4	(5)
Income Tax Expense (Benefit)	$ 55	$ 86	$ 147	$ 14	$ 59	$ 54	$ (54)	$ (33)

The following are reconciliations for the Registrants between the federal income taxes computed by multiplying pretax income by the federal statutory tax rate and the income taxes reported:

AEP	Year Ended December 31, 2025		2024		2023	
	(dollars in millions)					
Net Income	$ 3,696		$ 2,976		$ 2,213	
Income Tax Expense (Benefit)	129		(39)		55	
Pretax Income	$ 3,825		$ 2,937		$ 2,268	
	Amount	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
U.S. Federal Statutory Tax Rate	$ 803	21.0 %	$ 617	21.0 %	$ 476	21.0 %
State and Local Income Taxes, Net (a)	31	0.8 %	17	0.6 %	44	1.9 %
Tax Credits:						
Production Tax Credits	(244)	(6.4)%	(214)	(7.3)%	(175)	(7.7)%
Investment Tax Credits	(3)	(0.1)%	(58)	(2.0)%	(50)	(2.2)%
Other Credits	(4)	(0.1)%	(9)	(0.3)%	(1)	— %
Non-Taxable or Non-Deductible Items	—	— %	(3)	(0.1)%	1	— %
Changes in Unrecognized Tax Benefits	3	0.1 %	7	0.2 %	(5)	(0.2)%
Other Adjustments:						
Reversal of Origination Flow-Through	18	0.5 %	22	0.7 %	24	1.1 %
Tax Reform Excess ADIT Reversal	(62)	(1.6)%	(92)	(3.1)%	(151)	(6.7)%
Remeasurement of Excess ADIT	(383)	(10.0)%	(262)	(8.9)%	(46)	(2.0)%
AFUDC Equity	(41)	(1.1)%	(42)	(1.4)%	(38)	(1.7)%
Other	11	0.3 %	(22)	(0.7)%	(24)	(1.1)%
Income Tax Expense (Benefit)	$ 129		$ (39)		$ 55	
Effective Income Tax Rate	3.4 %		(1.3)%		2.4 %	

(a) In 2025, state taxes in West Virginia and local taxes in Ohio contributed to the majority of the tax effect. In 2024, local taxes in Ohio contributed to the majority of the tax effect. In 2023, state taxes in Indiana and West Virginia contributed to the majority of the tax effect.

AEP Texas	Year Ended December 31, 2025		2024		2023	
	(dollars in millions)					
Net Income	$ 488		$ 420		$ 370	
Income Tax Expense	101		102		86	
Pretax Income	$ 589		$ 522		$ 456	
	Amount	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
U.S. Federal Statutory Tax Rate	$ 124	21.0 %	$ 110	21.0 %	$ 96	21.0 %
State and Local Income Taxes, Net (a)	3	0.5 %	2	0.4 %	2	0.4 %
Tax Credits	(1)	(0.2)%	(1)	(0.2)%	(1)	(0.2)%
Other Adjustments:						
Tax Reform Excess ADIT Reversal	(11)	(1.9)%	(5)	(1.0)%	(6)	(1.3)%
Remeasurement of Excess ADIT	—	— %	6	1.1 %	—	— %
AFUDC Equity	(10)	(1.7)%	(9)	(1.7)%	(5)	(1.1)%
Other	(4)	(0.6)%	(1)	— %	—	— %
Income Tax Expense	$ 101		$ 102		$ 86	
Effective Income Tax Rate	17.1 %		19.6 %		18.8 %	

(a) State taxes in Texas contributed to the majority of the tax effect.

AEPTCo	Year Ended December 31, 2025		2024		2023	
			(dollars in millions)			
Net Income	$ 1,184		$ 688		$ 614	
Income Tax Expense	15		190		147	
Pretax Income	$ 1,199		$ 878		$ 761	
	Amount	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
U.S. Federal Statutory Tax Rate	$ 252	21.0 %	$ 185	21.0 %	$ 160	21.0 %
State and Local Income Taxes, Net (a)	31	2.6 %	20	2.3 %	1	0.1 %
Other Adjustments:						
Remeasurement of Excess ADIT	(256)	(21.4)%	—	— %	—	— %
AFUDC Equity	(16)	(1.3)%	(16)	(1.8)%	(15)	(2.0)%
Other	4	0.4 %	1	0.2 %	1	0.2 %
Income Tax Expense	$ 15		$ 190		$ 147	
Effective Income Tax Rate	1.3 %		21.7 %		19.3 %	

(a) In 2025 and 2024, state taxes in Indiana and West Virginia contributed to the majority of the tax effect. In 2023, state taxes in West Virginia contributed to the majority of the tax effect.

APCo	Year Ended December 31, 2025		2024		2023	
			(dollars in millions)			
Net Income	$ 457		$ 422		$ 294	
Income Tax Expense	86		75		14	
Pretax Income	$ 543		$ 497		$ 308	
	Amount	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
U.S. Federal Statutory Tax Rate	$ 114	21.0 %	$ 104	21.0 %	$ 65	21.0 %
State and Local Income Taxes, Net (a)	1	0.2 %	10	2.0 %	10	3.2 %
Tax Credits	(4)	(0.7)%	(1)	(0.2)%	—	— %
Other Adjustments:						
Reversal of Origination Flow-Through	6	1.1 %	5	1.0 %	9	2.9 %
Tax Reform Excess ADIT Reversal	(15)	(2.8)%	(30)	(6.0)%	(17)	(5.5)%
Remeasurement of Excess ADIT	(24)	(4.4)%	—	— %	(46)	(14.9)%
Removal Costs	(5)	(0.9)%	(11)	(2.2)%	(5)	(1.6)%
AFUDC Equity	(2)	(0.4)%	(2)	(0.4)%	(4)	(1.3)%
Flow-Through of CAMT	18	3.3 %	—	— %	—	— %
Other	(3)	(0.6)%	—	(0.1)%	2	0.8 %
Income Tax Expense	$ 86		$ 75		$ 14	
Effective Income Tax Rate	15.8 %		15.1 %		4.6 %	

(a) In 2025, state taxes in Virginia and West Virginia contributed to the majority of the tax effect. In 2024 and 2023, state taxes in West Virginia contributed to the majority of the tax effect.

I&M	Year Ended December 31, 2025		2024		2023	
			(dollars in millions)			
Net Income	$ 414		$ 391		$ 336	
Income Tax Expense (Benefit)	1		(95)		59	
Pretax Income	$ 415		$ 296		$ 395	
	Amount	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
U.S. Federal Statutory Tax Rate	$ 87	21.0 %	$ 62	21.0 %	$ 83	21.0 %
State and Local Income Taxes, Net (a)	14	3.4 %	6	2.0 %	18	4.6 %
Tax Credits:						
Production Tax Credits	(53)	(12.8)%	(69)	(23.3)%	—	— %
Other Credits	(3)	(0.7)%	(2)	(0.7)%	(2)	(0.5)%
Other Adjustments:						
Reversal of Origination Flow-Through	6	1.4 %	5	1.7 %	6	1.5 %
Tax Reform Excess ADIT Reversal	(10)	(2.4)%	(16)	(5.4)%	(33)	(8.4)%
Remeasurement of Excess ADIT	(38)	(9.2)%	(73)	(24.7)%	—	— %
Removal Costs	—	— %	(6)	(2.0)%	(12)	(3.0)%
Other	(2)	(0.5)%	(2)	(0.7)%	(1)	(0.3)%
Income Tax Expense (Benefit)	$ 1		$ (95)		$ 59	
Effective Income Tax Rate	0.2 %		(32.1)%		14.9 %	

(a) State Taxes in Indiana contributed to the majority of the tax effect.

OPCo	Year Ended December 31, 2025		2024		2023	
			(dollars in millions)			
Net Income	$ 328		$ 306		$ 328	
Income Tax Expense	72		52		54	
Pretax Income	$ 400		$ 358		$ 382	
	Amount	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
U.S. Federal Statutory Tax Rate	$ 84	21.0 %	$ 75	21.0 %	$ 80	21.0 %
State and Local Income Taxes, Net (a)	3	0.8 %	11	3.1 %	4	1.0 %
Other Adjustments:						
Tax Reform Excess ADIT Reversal	(12)	(3.0)%	(31)	(8.7)%	(29)	(7.6)%
AFUDC Equity	(4)	(1.0)%	(4)	(1.1)%	(3)	(0.8)%
Other	1	0.2 %	1	0.3 %	2	0.6 %
Income Tax Expense	$ 72		$ 52		$ 54	
Effective Income Tax Rate	18.0 %		14.6 %		14.2 %	

(a) Local taxes in Ohio municipalities contributed to the majority of the tax effect.

PSO	2025		2024		2023	
	Year Ended December 31,					
	(dollars in millions)					
Net Income	$ 252		$ 249		$ 209	
Income Tax Expense (Benefit)	(70)		(100)		(54)	
Pretax Income	$ 182		$ 149		$ 155	
	Amount	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
U.S. Federal Statutory Tax Rate	$ 38	21.0 %	$ 31	21.0 %	$ 33	21.0 %
State and Local Income Taxes, Net (a)	2	1.1 %	(1)	(0.7)%	3	1.9 %
Tax Credits:						
Production Tax Credits	(88)	(48.4)%	(74)	(49.7)%	(64)	(41.3)%
Other Credits	(1)	(0.5)%	(2)	(1.3)%	(1)	(0.6)%
Other Adjustments:						
Tax Reform Excess ADIT Reversal	(5)	(2.7)%	(6)	(4.0)%	(23)	(14.8)%
Remeasurement of Excess ADIT	(14)	(7.7)%	(49)	(32.9)%	—	— %
Other	(2)	(1.3)%	1	1.1 %	(2)	(0.7)%
Income Tax Expense (Benefit)	$ (70)		$ (100)		$ (54)	
Effective Income Tax Rate	(38.5)%		(66.5)%		(34.5) %	

(a) State taxes in Oklahoma contributed to the majority of the tax effect.

SWEPCo	2025		2024		2023	
	Year Ended December 31,					
	(dollars in millions)					
Net Income	$ 391		$ 326		$ 224	
Income Tax Expense (Benefit)	(95)		(184)		(33)	
Pretax Income	$ 296		$ 142		$ 191	
	Amount	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
U.S. Federal Statutory Tax Rate	$ 62	21.0 %	$ 30	21.0 %	$ 40	21.0 %
State and Local Income Taxes, Net (a)	(3)	(1.0)%	11	7.7 %	(4)	(2.1)%
Tax Credits						
Production Tax Credits	(98)	(33.1)%	(71)	(50.0)%	(67)	(35.1)%
Non-Taxable or Non-Deductible Items	—	— %	(1)	(0.7)%	—	— %
Other Adjustments:						
Tax Reform Excess ADIT Reversal	(6)	(2.0)%	(4)	(2.8)%	(13)	(6.8)%
Remeasurement of Excess ADIT	(46)	(15.5)%	(147)	(103.5)%	—	— %
Disallowance Cost	—	— %	—	— %	12	6.3 %
Other	(4)	(1.5)%	(2)	(1.3)%	(1)	(0.6)%
Income Tax Expense (Benefit)	$ (95)		$ (184)		$ (33)	
Effective Income Tax Rate	(32.1)%		(129.6)%		(17.3) %	

(a) State taxes in Louisiana contributed to the majority of the tax effect.

Income Taxes Paid

The following tables show the amount of income taxes paid or (received) on an annual basis, disaggregated by federal and state jurisdictions, for each Registrant:

Year Ended December 31, 2025	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(dollars in millions)				
Federal	$ 70	$ 46	$ 191	$ 88	$ 23	$ 62	$ (158)	$ (91)
State and Local:								
IN	$ 16	$ —	$ 11	$ —	$ 14	$ —	$ —	$ —
MI	—	—	—	—	4	—	—	—
TX	5	4	—	—	—	—	—	1
WV	8	—	11	17	1	—	—	—
All Other	4	—	1	—	1	—	—	—
Total To/(From) Tax Authority	$ 103	$ 50	$ 214	$ 105	$ 43	$ 62	$ (158)	$ (90)
Transfer Credits	(187)	—	—	—	—	—	(90)	(97)
Total Cash Paid/(Received)	$ (84)	$ 50	$ 214	$ 105	$ 43	$ 62	$ (248)	$ (187)

Year Ended December 31, 2024	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(dollars in millions)				
Federal	$ 100	$ 11	$ 43	$ 48	$ 17	$ 19	$ (15)	$ (15)
State and Local:								
IN	$ 7	$ —	$ —	$ —	$ 7	$ —	$ —	$ —
WV	9	—	—	—	—	—	—	—
All Other	17	—	—	—	—	—	—	—
Total To/(From) Tax Authority	$ 133	$ 11	$ 43	$ 48	$ 24	$ 19	$ (15)	$ (15)
Transfer Credits	(202)	—	—	—	—	—	(96)	(89)
Total Cash Paid/(Received)	$ (69)	$ 11	$ 43	$ 48	$ 24	$ 19	$ (111)	$ (104)

Year Ended December 31, 2023	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(dollars in millions)				
Federal	$ 38	$ 12	$ 87	$ 47	$ 93	$ 39	$ (11)	$ (41)
State and Local:								
IN	$ 16	$ —	$ —	$ —	$ 16	$ —	$ —	$ —
OH	10	—	1	—	—	—	—	—
TX	4	—	—	—	—	—	—	—
All Other	10	—	—	—	—	—	—	—
Total To/(From) Tax Authority	$ 78	$ 12	$ 88	$ 47	$ 109	$ 39	$ (11)	$ (41)
Transfer Credits	(102)	—	—	—	—	—	(35)	(41)
Total Cash Paid/(Received)	$ (24)	$ 12	$ 88	$ 47	$ 109	$ 39	$ (46)	$ (82)

Net Deferred Tax Liability

The following tables show elements of the net deferred tax liability and significant temporary differences for each Registrant:

Year Ended December 31, 2025	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(dollars in millions)				
Deferred Tax Assets	$ 2,786	$ 131	$ 170	$ 411	$ 1,160	$ 171	$ 287	$ 328
Deferred Tax Liabilities	(13,737)	(1,561)	(1,651)	(2,541)	(2,379)	(1,439)	(1,400)	(1,786)
Net Deferred Tax Liabilities	$ (10,951)	$ (1,430)	$ (1,481)	$ (2,130)	$ (1,219)	$ (1,268)	$ (1,113)	$ (1,458)
Property Related Temporary Differences	$ (9,456)	$ (1,442)	$ (1,526)	$ (1,881)	$ (49)	$ (1,333)	$ (1,195)	$ (1,477)
Amounts Due to Customers for Future Income Taxes	641	105	44	109	57	92	74	74
Securitized Assets	(211)	(28)	—	(19)	—	—	—	(50)
Regulatory Assets	(902)	(73)	(4)	(308)	(46)	(48)	(60)	(119)
Accrued Nuclear Decommissioning	(1,180)	—	—	—	(1,180)	—	—	—
Net Operating Loss Carryforward	155	—	—	—	—	—	44	45
Valuation Allowance	(49)	—	—	—	—	—	—	(3)
Tax Credit Carryforward	148	10	—	33	—	43	33	—
Operating Lease Liability	166	12	1	23	14	11	32	50
Investment in Partnership	(306)	—	—	—	—	(1)	—	(1)
All Other, Net	43	(14)	4	(87)	(15)	(32)	(41)	23
Net Deferred Tax Liabilities	$ (10,951)	$ (1,430)	$ (1,481)	$ (2,130)	$ (1,219)	$ (1,268)	$ (1,113)	$ (1,458)

Year Ended December 31, 2024	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(dollars in millions)				
Deferred Tax Assets	$ 2,652	$ 139	$ 173	$ 379	$ 1,072	$ 187	$ 267	$ 293
Deferred Tax Liabilities	(12,624)	(1,462)	(1,452)	(2,413)	(2,248)	(1,388)	(1,198)	(1,564)
Net Deferred Tax Liabilities	$ (9,972)	$ (1,323)	$ (1,279)	$ (2,034)	$ (1,176)	$ (1,201)	$ (931)	$ (1,271)
Property Related Temporary Differences	$ (8,940)	$ (1,364)	$ (1,417)	$ (1,785)	$ (190)	$ (1,291)	$ (1,010)	$ (1,353)
Amounts Due to Customers for Future Income Taxes	780	109	121	119	73	96	81	90
Securitized Assets	(133)	(27)	—	(26)	—	—	—	(81)
Regulatory Assets	(966)	(63)	—	(302)	(49)	(45)	(53)	(87)
Accrued Nuclear Decommissioning	(1,052)	—	—	—	(1,052)	—	—	—
Net Operating Loss Carryforward	110	—	2	—	—	3	28	36
Valuation Allowance	(35)	—	—	—	—	—	—	—
Tax Credit Carryforward	198	4	—	—	40	39	27	32
Operating Lease Liability	145	12	—	16	14	13	27	36
Investment in Partnership	(302)	—	—	—	—	(1)	—	(2)
All Other, Net	223	6	15	(56)	(12)	(15)	(31)	58
Net Deferred Tax Liabilities	$ (9,972)	$ (1,323)	$ (1,279)	$ (2,034)	$ (1,176)	$ (1,201)	$ (931)	$ (1,271)

Federal and State Income Tax Audit Status

AEP is not currently under IRS audit and the statute of limitations (SOL) for the IRS to examine AEP and subsidiaries originally filed federal return has expired for tax years prior to 2022. In July 2025, AEP received notification that its 2023 federal income tax return was selected for IRS examination. However, this examination has yet to begin.

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.

Net Income Tax Operating Loss Carryforward

As of December 31, 2025, AEP, PSO and SWEPCo have state income tax net operating loss deferred tax assets as indicated in the table below:

Company	State/Municipality	Future State Income Tax Benefit	Years of Expiration
AEP	Arkansas	$ 15	2031 - 2035
AEP	Illinois	5	2039 - 2041
AEP	Kentucky	11	2030 - 2037
AEP	Louisiana	41	Indefinite
AEP	Michigan	1	2029 - 2032
AEP	Ohio Municipal	62	2026 - 2030
AEP	Oklahoma	54	2037
AEP	Tennessee	4	2032 - 2040
PSO	Oklahoma	55	2037
SWEPCo	Arkansas	15	2031 - 2035
SWEPCo	Louisiana	41	Indefinite

Tax Credit Carryforward

As of December 31, 2025, AEP and the Registrants have federal tax credit carryforwards as indicated in the table below. The federal tax credit carryforwards are entirely CAMT credits which have an indefinite carryforward period. AEP and the Registrants anticipate future federal taxable income will be sufficient to realize the tax benefits of the CAMT credits.

As of December 31, 2025, AEP and PSO have state tax credit carryforwards as indicated in the table below, which have an indefinite carryforward period.

Company	Total Federal Tax Credit Carryforward	Total State Tax Credit Carryforward
	(dollars in millions)	
AEP	$ 108	$ 41
AEP Texas	10	—
APCo	28	—
OPCo	43	—
PSO	—	41

Valuation Allowance

AEP assesses the available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that it is more-likely-than-not that AEP will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount. Objective evidence evaluated includes whether AEP has a history of recognizing income, future reversals of existing temporary differences and tax planning strategies.

Valuation allowance activity for the years ended December 31, 2025, 2024 and 2023 were not material.

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 or influence 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 prospective and has no material impact on the current period financial statements.

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. This guidance is not expected to have a material impact on the Registrants.

On September 30, 2025, the Department of Treasury and the IRS issued interim guidance regarding the application of CAMT, Notice 2025-49. This guidance is not expected to have a material impact on the Registrants.

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.

13. LEASES

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

The Registrants lease property, plant and equipment including, but not limited to, fleet, information technology and real estate leases. These leases require payments of non-lease components, including related property taxes, operating and maintenance costs. AEP does not separate non-lease components from associated lease components. Many of these leases have purchase or renewal options. Leases not renewed are often replaced by other leases. Options to renew or purchase a lease are included in the measurement of lease assets and liabilities if it is reasonably certain the Registrant will exercise the option.

Lease obligations are measured using the discount rate implicit in the lease when that rate is readily determinable. AEP has visibility into the rate implicit in the lease when assets are leased from selected financial institutions under master leasing agreements. When the implicit rate is not readily determinable, the Registrants measure their lease obligation using their estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk-free rate and a secured credit spread relative to the lessee on a matched maturity basis.

Operating lease rentals and finance lease amortization costs are generally charged to Other Operation and Maintenance expense in accordance with ratemaking treatment for regulated operations. Interest on finance lease liabilities is generally charged to Interest Expense. Lease costs associated with capital projects are included in Property, Plant and Equipment on the balance sheets. For regulated operations with finance leases, a finance lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Finance leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs were as follows:

Year Ended December 31, 2025	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Cost	$ 137	$ 18	$ 1	$ 20	$ 20	$ 17	$ 14	$ 20
Finance Lease Cost:								
Amortization of Right-of-Use Assets	51	8	—	9	6	4	3	4
Interest on Lease Liabilities	10	2	—	1	2	1	1	1
Total Lease Rental Costs (a)	$ 198	$ 28	$ 1	$ 30	$ 28	$ 22	$ 18	$ 25

Year Ended December 31, 2024	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Cost	$ 146	$ 32	$ 1	$ 18	$ 20	$ 17	$ 14	$ 18
Finance Lease Cost:								
Amortization of Right-of-Use Assets	64	8	—	9	7	5	3	13
Interest on Lease Liabilities	12	1	—	2	2	1	1	1
Total Lease Rental Costs (a)	$ 222	$ 41	$ 1	$ 29	$ 29	$ 23	$ 18	$ 32

Year Ended December 31, 2023	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Cost	$ 150	$ 34	$ 1	$ 19	$ 20	$ 17	$ 14	$ 18
Finance Lease Cost:								
Amortization of Right-of-Use Assets	69	8	—	8	7	5	3	20
Interest on Lease Liabilities	12	1	—	2	2	1	1	1
Total Lease Rental Costs (a)	$ 231	$ 43	$ 1	$ 29	$ 29	$ 23	$ 18	$ 39

(a) Excludes variable and short-term lease costs, which were immaterial.

Supplemental information related to leases are shown in the tables below:

December 31, 2025	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
Weighted-Average Remaining Lease Term (years):								
Operating Leases	17.33	4.33	3.29	13.03	3.73	4.04	25.59	29.02
Finance Leases	4.53	4.80	0.00	4.42	5.12	4.24	4.61	5.60
Weighted-Average Discount Rate:								
Operating Leases	4.74 %	4.57 %	4.51 %	5.08 %	4.61 %	4.36 %	4.48 %	4.96 %
Finance Leases	6.36 %	5.99 %	— %	5.73 %	9.04 %	5.74 %	5.71 %	5.90 %

December 31, 2024	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
Weighted-Average Remaining Lease Term (years):								
Operating Leases	12.80	4.45	2.29	5.39	4.43	4.64	23.68	21.97
Finance Leases	4.81	5.04	0.00	4.09	4.83	4.58	5.44	6.14
Weighted-Average Discount Rate:								
Operating Leases	3.89 %	4.29 %	4.55 %	4.20 %	4.11 %	4.17 %	3.76 %	3.60 %
Finance Leases	6.43 %	5.73 %	— %	6.69 %	9.07 %	5.59 %	5.48 %	5.73 %

Year Ended December 31, 2025	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Cash paid for amounts included in the measurement of lease liabilities:								
Operating Cash Flows Used for Operating Leases	$ 135	$ 18	$ 1	$ 20	$ 20	$ 17	$ 13	$ 20
Operating Cash Flows Used for Finance Leases	10	1	—	1	2	1	1	1
Financing Cash Flows Used for Finance Leases	51	8	—	9	6	4	3	4
Non-cash Acquisitions Under Operating Leases	$ 190	$ 12	$ 1	$ 44	$ 17	$ 4	$ 28	$ 70

Year Ended December 31, 2024	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Cash paid for amounts included in the measurement of lease liabilities:								
Operating Cash Flows Used for Operating Leases	$ 144	$ 32	$ 1	$ 18	$ 20	$ 17	$ 13	$ 17
Operating Cash Flows Used for Finance Leases	12	1	—	2	2	1	1	2
Financing Cash Flows Used for Finance Leases	65	8	—	9	7	5	3	14
Non-cash Acquisitions Under Operating Leases	$ 82	$ 6	$ 1	$ 9	$ 15	$ 5	$ 3	$ 27

The following tables show property, plant and equipment under finance leases and noncurrent assets under operating leases and related obligations recorded on the balance sheets. Unless shown as a separate line on the balance sheets due to materiality, net operating lease assets are included in Deferred Charges and Other Noncurrent Assets, current finance lease obligations are included in Other Current Liabilities and long-term finance lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets. Lease obligations are not recognized on the balance sheets for lease agreements with a lease term of less than twelve months.

December 31, 2025	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Property, Plant and Equipment Under Finance Leases:								
Generation	$ 48	$ —	$ —	$ 40	$ 5	$ —	$ 1	$ 2
Other Property, Plant and Equipment	291	53	—	19	38	28	23	29
Total Property, Plant and Equipment	339	53	—	59	43	28	24	31
Accumulated Amortization	184	29	—	44	25	15	13	14
Net Property, Plant and Equipment Under Finance Leases	$ 155	$ 24	$ —	$ 15	$ 18	$ 13	$ 11	$ 17
Obligations Under Finance Leases:								
Noncurrent Liability	$ 112	$ 17	$ —	$ 10	$ 13	$ 8	$ 8	$ 13
Liability Due Within One Year	43	7	—	4	4	4	3	4
Total Obligations Under Finance Leases	$ 155	$ 24	$ —	$ 14	$ 17	$ 12	$ 11	$ 17

December 31, 2024	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Property, Plant and Equipment Under Finance Leases:								
Generation	$ 74	$ —	$ —	$ 42	$ 17	$ —	$ 1	$ 2
Other Property, Plant and Equipment	284	53	—	19	38	30	23	30
Total Property, Plant and Equipment	358	53	—	61	55	30	24	32
Accumulated Amortization	194	28	—	42	33	16	12	13
Net Property, Plant and Equipment Under Finance Leases	$ 164	$ 25	$ —	$ 19	$ 22	$ 14	$ 12	$ 19
Obligations Under Finance Leases:								
Noncurrent Liability	$ 117	$ 18	$ —	$ 11	$ 16	$ 10	$ 9	$ 15
Liability Due Within One Year	47	7	—	8	6	4	3	4
Total Obligations Under Finance Leases	$ 164	$ 25	$ —	$ 19	$ 22	$ 14	$ 12	$ 19

December 31, 2025	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Assets	$ 661	$ 52	$ 3	$ 95	$ 52	$ 50	$ 126	$ 198
Obligations Under Operating Leases:								
Noncurrent Liability	$ 578	$ 40	$ 2	$ 81	$ 37	$ 37	$ 122	$ 195
Liability Due Within One Year	100	14	1	15	17	13	11	7
Total Obligations Under Operating Leases	$ 678	$ 54	$ 3	$ 96	$ 54	$ 50	$ 133	$ 202

December 31, 2024	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Assets	$ 580	$ 54	$ 2	$ 67	$ 52	$ 60	$ 106	$ 141
Obligations Under Operating Leases:								
Noncurrent Liability	$ 504	$ 43	$ 1	$ 54	$ 40	$ 48	$ 102	$ 138
Liability Due Within One Year	92	13	1	14	12	12	10	8
Total Obligations Under Operating Leases	$ 596	$ 56	$ 2	$ 68	$ 52	$ 60	$ 112	$ 146

Future minimum lease payments consisted of the following as of December 31, 2025:

Finance Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2026	$ 52	$ 8	$ —	$ 5	$ 5	$ 4	$ 4	$ 5
2027	41	6	—	3	5	3	3	4
2028	30	4	—	2	4	2	2	3
2029	21	3	—	2	3	1	1	3
2030	15	2	—	1	2	1	1	2
After 2030	21	5	—	2	3	1	2	4
Total Future Minimum Lease Payments	180	28	—	15	22	12	13	21
Less: Imputed Interest	25	4	—	1	5	—	2	4
Estimated Present Value of Future Minimum Lease Payments	$ 155	$ 24	$ —	$ 14	$ 17	$ 12	$ 11	$ 17

Operating Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2026	$ 133	$ 17	$ 1	$ 20	$ 19	$ 16	$ 13	$ 21
2027	114	14	1	19	15	14	12	19
2028	99	11	1	16	13	12	11	17
2029	71	7	—	12	8	7	9	14
2030	47	5	—	8	2	3	7	12
After 2030	607	7	—	68	2	3	178	339
Total Future Minimum Lease Payments	1,071	61	3	143	59	55	230	422
Less: Imputed Interest	393	7	—	47	5	5	97	220
Estimated Present Value of Future Minimum Lease Payments	$ 678	$ 54	$ 3	$ 96	$ 54	$ 50	$ 133	$ 202

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 December 31, 2025, the maximum potential loss by the Registrants for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was as follows:

Company	Maximum Potential Loss	
	(in millions)	
AEP	$	38
AEP Texas		9
APCo		5
I&M		4
OPCo		6
PSO		4
SWEPCo		4

Lessor Activity

The Registrants' lessor activity was immaterial as of and for the years ended December 31, 2025 and December 31, 2024, respectively.

14. VOLUNTARY SEVERANCE PROGRAM

In April 2024, management announced a voluntary severance program designed to achieve a reduction in the size of AEP's workforce. Approximately 7,400 of AEP's 16,800 employees were eligible to participate in the program. Approximately 1,000 employees chose to take the voluntary severance package and substantially all terminated employment in July 2024. The severance program provides two weeks of base pay for every year of service with a minimum of four weeks and a maximum of 52 weeks of base pay. Certain positions impacted by the voluntary severance program were refilled to maintain safe, effective and efficient operations. The program was completed to help offset increasing operating expenses and high interest costs.

AEP recorded a charge to expense in the second quarter of 2024 related to this voluntary severance program.

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Severance Expense Incurred	$ 122	$ 20	$ 11	$ 26	$ 15	$ 15	$ 10	$ 17

These expenses were primarily included in Other Operation and Maintenance on the statements of income and Other Current Liabilities on the balance sheets. Settlement accounting was triggered for the qualified pension plan in November 2024 under the accounting guidance for "Compensation - Retirement Benefits" and a settlement charge of $90 million was recorded. As of December 31, 2025, all incurred expenses have been settled. AEP will seek approval for the pension expense related to regulated operations. See Note 8 - Benefit Plans for additional information associated with the plan.

15. FINANCING ACTIVITIES

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

Common Stock (Applies to AEP)

The following table is a reconciliation of common stock share activity:

Shares of AEP Common Stock	Issued	Held in Treasury	
Balance, December 31, 2022	525,099,321	11,233,240	
Issued	2,269,836	—	
Treasury Stock Reissued	—	(10,048,668)	(a)
Balance, December 31, 2023	527,369,157	1,184,572	
Issued	6,725,373	—	
Treasury Stock Reacquired	—	2,243	
Balance, December 31, 2024	534,094,530	1,186,815	
Issued	7,953,758	—	
Balance, December 31, 2025	542,048,288	1,186,815	

(a) Reissued Treasury Stock used to fulfill share commitments related to AEP's Equity Units.

ATM Program

In November 2025, AEP filed a prospectus supplement and executed an Equity Distribution Agreement, pursuant to which AEP may sell, from time to time, up to an aggregate of $3.5 billion of its common stock through an ATM offering program, including an equity forward sales component. The compensation paid to the selling agents by AEP may be up to 2% of the gross offering proceeds of the shares. For the year ended 2025, AEP issued 176,402 shares of common stock and received net cash proceeds of $21 million under the ATM program. As of December 31, 2025, approximately $3.5 billion of equity is available for issuance under the ATM program.

Forward Sale of Equity

In March 2025, AEP entered into separate forward sale agreements with non-affiliate forward purchasers relating to 22,549,020 shares of AEP's common stock at an initial price of $102.00 per share, exclusive of an underwriting discount equal to $2.244 per share. Except in certain specified circumstances that would require physical share settlement, AEP may elect to settle the forward sale transaction by means of physical, cash or net share settlement. The timing of the settlement of the forward sale agreements is also at AEP's discretion, and management currently expects settlement to occur on or prior to December 31, 2026. To the extent the forward sale agreements are physically settled, AEP will issue common stock to the forward purchasers and receive cash proceeds based on the applicable forward sale price on the settlement date as defined in the forward sale agreements. For the year ended 2025, AEP issued 5,022,229 shares of common stock and received net cash proceeds of $500 million. As of December 31, 2025, AEP expects approximately $1.7 billion of net cash proceeds from the remaining physical settlement of the forward sale agreements and management anticipates using any future proceeds for general corporate purposes, which may include capital contributions to utility subsidiaries, acquisitions or repayment of debt. The forward sale transactions will be classified as equity transactions because they are indexed to AEP's common stock and physical settlement is within AEP's control.

Long-term Debt

The following table details long-term debt outstanding:

Company	Maturity	Weighted-Average Interest Rate as of December 31, 2025	Interest Rate Ranges as of December 31, 2025	Interest Rate Ranges as of December 31, 2024	Outstanding as of December 31, 2025	Outstanding as of December 31, 2024
AEP					(in millions)	
Senior Unsecured Notes	2026-2055	4.45%	1.63%-8.13%	1.00%-8.13%	$ 37,190	$ 36,411
Pollution Control Bonds (a)	2026-2038 (b)	3.62%	2.40%-4.70%	0.63%-4.70%	1,637	1,771
Notes Payable – Nonaffiliated (c)	2026-2034	5.97%	2.43%-6.89%	0.93%-6.89%	683	610
Securitization Bonds	2028-2045 (d)	4.71%	2.29%-5.30%	2.06%-4.88%	984	578
Spent Nuclear Fuel Obligation (e)					330	316
Junior Subordinated Notes	2027-2054	5.83%	3.88%-7.05%	3.88%-7.05%	4,681	2,579
Other Long-term Debt	2026-2059	4.88%	3.00%-13.72%	3.00%-13.72%	1,817	378
Total Long-term Debt Outstanding					$ 47,322	$ 42,643
AEP Texas						
Senior Unsecured Notes	2026-2055	4.62%	2.10%-6.76%	2.10%-6.76%	$ 6,472	$ 5,874
Pollution Control Bonds (a)	2029-2030 (b)	3.88%	2.60%-4.55%	2.60%-4.55%	441	440
Securitization Bonds	2029 (d)	2.29%	2.29%	2.06%-2.29%	102	127
Other Long-term Debt	2059	4.50%	4.50%	4.50%	1	1
Total Long-term Debt Outstanding					$ 7,016	$ 6,442
AEPTCo						
Senior Unsecured Notes	2026-2053	4.21%	2.75%-5.52%	2.75%-5.52%	$ 6,100	$ 5,768
Other Long-term Debt	2028	4.83%	4.83%	—%	499	—
Total Long-term Debt Outstanding					$ 6,599	$ 5,768
APCo						
Senior Unsecured Notes	2027-2050	4.84%	2.70%-7.00%	2.70%-7.00%	$ 4,688	$ 4,984
Pollution Control Bonds (a)	2028-2038 (b)	3.92%	3.30%-3.70%	0.63%-4.22%	379	430
Securitization Bonds	2028 (d)	3.77%	3.77%	3.77%	92	120
Other Long-term Debt	2026-2028	4.89%	4.83%-13.72%	5.75%-13.72%	1,100	127
Total Long-term Debt Outstanding					$ 6,259	$ 5,661
I&M						
Senior Unsecured Notes	2028-2053	4.52%	3.25%-6.05%	3.25%-6.05%	$ 2,847	$ 2,845
Pollution Control Bonds (a)	2029 (b)	3.70%	3.70%	0.75%-3.05%	149	190
Notes Payable – Nonaffiliated (c)	2026-2030	5.24%	3.44%-6.41%	0.93%-6.41%	235	143
Spent Nuclear Fuel Obligation (e)					330	316
Total Long-term Debt Outstanding					$ 3,561	$ 3,494
OPCo						
Senior Unsecured Notes	2030-2051	4.16%	1.63%-6.60%	1.63%-6.60%	$ 3,718	$ 3,716
Total Long-term Debt Outstanding					$ 3,718	$ 3,716
PSO						
Senior Unsecured Notes	2026-2051	4.59%	2.20%-6.63%	2.20%-6.63%	$ 3,525	$ 2,854
Other Long-term Debt	2027	3.00%	3.00%	3.00%	1	2
Total Long-term Debt Outstanding					$ 3,526	$ 2,856
SWEPCo						
Senior Unsecured Notes	2026-2051	3.73%	1.65%-6.20%	1.65%-6.20%	$ 3,653	$ 3,650
Notes Payable – Affiliated	2028	4.24%	4.24%	—%	1,000	—
Securitization Bonds	2039 (d)	4.88%	4.88%	4.88%	321	331
Total Long-term Debt Outstanding					$ 4,974	$ 3,981

(a) For certain series of Pollution Control Bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and insurance policies support certain series. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year - Nonaffiliated on the balance sheets.

(b) Certain Pollution Control Bonds are subject to redemption earlier than the maturity date.

(c) Notes payable represent outstanding promissory notes issued under term loan agreements and credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(d) Dates represent the scheduled final payment dates for the securitization bonds. The legal maturity date is one to two years later. These bonds have been classified for maturity and repayment purposes based on the scheduled final payment date.

(e) Spent Nuclear Fuel Obligation consists of a liability along with accrued interest for disposal of SNF. See “Spent Nuclear Fuel Disposal” section of Note 6 for additional information.

As of December 31, 2025, outstanding long-term debt was payable as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2026	$ 3,194	$ 75	$ 425	$ 1,131	$ 117	$ —	$ 51	$ 917
2027	2,453	26	—	356	68	—	—	17
2028	3,468	526	559	413	388	—	—	1,593
2029	2,887	627	55	—	162	—	100	19
2030	1,809	942	60	—	1	350	—	20
After 2030	33,896	4,871	5,566	4,400	2,855	3,400	3,400	2,434
Principal Amount	47,707	7,067	6,665	6,300	3,591	3,750	3,551	5,000
Unamortized Discount, Net and Debt Issuance Costs	(385)	(51)	(66)	(41)	(30)	(32)	(25)	(26)
Total Long-term Debt Outstanding	$ 47,322	$ 7,016	$ 6,599	$ 6,259	$ 3,561	$ 3,718	$ 3,526	$ 4,974

Financing Activities Subsequent Events

In January 2026, AEPTCo issued $114 million of variable rate Other Long-term Debt due in 2028.

In January 2026, I&M retired $11 million of Notes Payable related to DCC Fuel.

In January 2026, Transource Energy issued $14 million of variable rate Other Long-term Debt due in 2028.

In February 2026, AEP made capital contributions of $81 million, $38 million and $128 million to APCo, OPCo and SWEPCo, respectively.

In February 2026, AEP Texas retired $12 million of Securitization Bonds.

In February 2026, APCo retired $14 million of Securitization Bonds.

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 0.9% of consolidated tangible net assets as of December 31, 2025. 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's 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 most restrictive dividend limitation for certain AEP subsidiaries is through the Federal Power Act restriction, while for other AEP subsidiaries the most restrictive dividend limitation is through the credit agreements. As of December 31, 2025, the maximum amount of restricted net assets of AEP's subsidiaries that may not be distributed to the Parent in the form of a loan, advance or dividend was $20.5 billion.

The Federal Power Act restriction limits the ability of the AEP subsidiaries owning hydroelectric generation to pay dividends out of retained earnings. Additionally, the credit agreement covenant restrictions can limit the ability of the AEP subsidiaries to pay dividends out of retained earnings. As of December 31, 2025, the amount of any such restrictions were as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Restricted Retained Earnings	$ 2,690 (a)	$ 904	$ —	$ 901	$ 663	$ —	$ 17	$ —

(a) Includes the restrictions of consolidated and non-consolidated subsidiaries.

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. AEP may not declare or pay any cash dividend or distribution on its common stock during any period when AEP defers interest on its junior subordinated notes. As of December 31, 2025, AEP had $15.1 billion of available retained earnings to pay dividends to common shareholders. AEP paid $2.0 billion, $1.9 billion and $1.8 billion of dividends to common shareholders for the years ended December 31, 2025, 2024 and 2023, respectively.

Lines of Credit and Short-term Debt (Applies to AEP and SWEPCo)

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. As of December 31, 2025, AEP had $6 billion in revolving credit facilities to support its commercial paper program.

Securitized Debt for Receivables, for the year ended 2025, had a weighted-average interest rate of 4.46% and a maximum amount outstanding of $900 million. The commercial paper program, for the year ended 2025, had a weighted-average yield of 4.47% and a maximum amount outstanding of $2.9 billion. AEP's outstanding short-term debt was as follows:

		December 31,			
		2025		2024	
Company	**Type of Debt**	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
		(in millions)		**(in millions)**	
AEP	Securitized Debt for Receivables (b)	$ 900	4.00 %	$ 900	4.73 %
AEP	Commercial Paper	605	3.92 %	1,618	4.70 %
SWEPCo	Notes Payable	3	6.30 %	6	6.69 %
	Total Short-term Debt	$ 1,508		$ 2,524	

(a) Weighted-average rate of all borrowings outstanding as of December 31, 2025 and 2024, respectively.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

Corporate Borrowing Program (Applies to 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 December 31, 2025 and 2024 are included in Advances to Affiliates and Advances from Affiliates, respectively, on the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and corresponding authorized borrowing limits are described in the following tables:

Year Ended December 31, 2025:

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 December 31, 2025	Authorized Short-term Borrowing Limit	
			(in millions)				
AEP Texas	$ 468	$ 486	$ 159	$ 94	$ (188)	$ 750	
AEPTCo	404	312	176	50	(140)	1,070	(a)
APCo	264	464	126	25	(192)	750	
I&M	145	290	71	132	192	750	
OPCo	271	166	120	82	(79)	600	
PSO	505	391	183	166	(171)	750	
SWEPCo	472	1,117	254	110	23	750	

Year Ended December 31, 2024:

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 December 31, 2024	Authorized Short-term Borrowing Limit	
			(in millions)				
AEP Texas	$ 375	$ 274	$ 234	$ 165	$ (285)	$ 600	
AEPTCo	313	332	72	138	(73)	820	(a)
APCo	400	132	103	30	(77)	750	
I&M	136	8	59	4	(127)	500	
OPCo	310	183	181	94	115	600	
PSO	309	315	171	288	232	750	
SWEPCo	362	59	250	57	(275)	750	

(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 tables does not include short-term lending activity of certain AEP nonutility subsidiaries. AEP Texas' wholly-owned subsidiary, AEP Texas North Generation Company, LLC and SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC participate in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of December 31, 2025 and 2024 are included in Advances to Affiliates on each subsidiaries' balance sheets. The Nonutility Money Pool participants' money pool activity is described in the following tables:

Year Ended December 31, 2025:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of December 31, 2025
		(in millions)	
AEP Texas	$ 7	$ 7	$ 7
SWEPCo	2	2	—

Year Ended December 31, 2024:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of December 31, 2024
		(in millions)	
AEP Texas	$ 7	$ 7	$ 7
SWEPCo	3	3	2

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs. The amounts of outstanding loans to and borrowings from AEP as of December 31, 2025 and 2024 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 limits are described in the following tables:

Year Ended December 31, 2025:

Company	Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of December 31, 2025	Loans to AEP as of December 31, 2025	Authorized Short-term Borrowing Limit (a)
				(in millions)			
AEPTCo Parent	$ 107	$ 153	$ 18	$ 54	$ —	$ 70	$ —
SWTCo	2	—	2	—	2	—	50
Midwest Transmission Holdings	—	36	—	4	—	—	—

Year Ended December 31, 2024:

Company	Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of December 31, 2024	Loans to AEP as of December 31, 2024	Authorized Short-term Borrowing Limit (a)
				(in millions)			
AEPTCo Parent	$ 49	$ 149	$ 15	$ 57	$ —	$ 20	$ —
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:

	Years Ended December 31,		
	2025	2024	2023
Maximum Interest Rate	4.83 %	5.79 %	5.81 %
Minimum Interest Rate	3.40 %	4.74 %	4.66 %

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

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for the Years Ended December 31,			Average Interest Rate for Funds Loaned to the Utility Money Pool for the Years Ended December 31,		
Company	2025	2024	2023	2025	2024	2023
AEP Texas	4.60 %	5.48 %	5.46 %	4.19 %	5.45 %	5.71 %
AEPTCo	4.48 %	5.51 %	5.41 %	4.44 %	5.50 %	5.56 %
APCo	4.50 %	5.51 %	5.54 %	4.46 %	5.41 %	5.54 %
I&M	4.69 %	5.40 %	5.14 %	4.12 %	5.44 %	5.57 %
OPCo	4.43 %	5.70 %	5.43 %	4.70 %	5.20 %	5.60 %
PSO	4.51 %	5.50 %	5.51 %	4.68 %	4.79 %	5.35 %
SWEPCo	4.67 %	5.41 %	5.34 %	4.29 %	4.78 %	5.72 %

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

Year Ended December 31,	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
2025	AEP Texas	4.76 %	3.89 %	4.52 %
2025	SWEPCo	4.76 %	4.62 %	4.69 %
2024	AEP Texas	5.79 %	4.74 %	5.46 %
2024	SWEPCo	5.79 %	4.74 %	5.45 %
2023	AEP Texas	5.81 %	4.66 %	5.54 %
2023	SWEPCo	5.81 %	4.66 %	5.56 %

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

Year Ended December 31,	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
2025	4.76 %	3.89 %	4.76 %	3.89 %	4.55 %	4.43 %
2024	5.79 %	4.66 %	5.79 %	4.66 %	5.53 %	5.56 %
2023	5.81 %	4.53 %	5.81 %	4.53 %	5.56 %	5.51 %

Interest expense related to short-term borrowing activities with the Utility Money Pool, Nonutility Money Pool and direct borrowing financing relationship are included in Interest Expense on each of the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries incurred interest expense for all short-term borrowing activities as follows:

	Years Ended December 31,		
Company	2025	2024	2023
		(in millions)	
AEP Texas	$ 5	$ 7	$ 11
AEPTCo	8	4	8
APCo	7	6	17
I&M	2	4	3
OPCo	4	4	10
PSO	6	9	2
SWEPCo	6	14	8

Interest income related to short-term lending activities with the Utility Money Pool, Nonutility Money Pool and direct borrowing financing relationship are included in Interest Income, unless shown as Other Income due to materiality, on each of the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries earned interest income for all short-term lending activities as follows:

Company	Years Ended December 31, 2025	2024	2023
		(in millions)	
AEP Texas	$ 1	$ 4	$ —
AEPTCo	4	11	7
APCo	1	2	1
I&M	3	—	2
OPCo	1	3	—
PSO	2	1	2
SWEPCo	3	—	—

Credit Facilities

See "Letters of Credit" section of Note 6 for additional information.

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 December 31, 2025, the affiliated utility subsidiaries were in compliance with all requirements under the agreement.

Accounts receivable information for AEP Credit was as follows:

	Years Ended December 31, 2025	2024	2023
		(dollars in millions)	
Effective Interest Rates on Securitization of Accounts Receivable	4.46 %	5.39 %	5.33 %
Net Uncollectible Accounts Receivable Written Off	$ 34	$ 29	$ 31

	December 31, 2025	2024
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 1,230	$ 1,117
Short-term – Securitized Debt of Receivables	900	900
Delinquent Securitized Accounts Receivable	66	56
Bad Debt Reserves Related to Securitization	42	45
Unbilled Receivables Related to Securitization	368	336

AEP Credit's delinquent customer accounts receivable represent accounts greater than 30 days past due.

Securitized Accounts Receivables – AEP Credit (Applies to 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 agreement were:

Company	December 31, 2025	December 31, 2024
	(in millions)	
APCo	$ 203	$ 193
I&M	175	161
OPCo	501	471
PSO	140	111
SWEPCo	169	154

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

Company	Years Ended December 31, 2025	2024	2023
		(in millions)	
APCo	$ 14	$ 16	$ 17
I&M	15	15	16
OPCo	30	30	30
PSO	13	14	15
SWEPCo	15	18	19

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

Company	Years Ended December 31, 2025	2024	2023
		(in millions)	
APCo	$ 1,992	$ 1,954	$ 1,820
I&M	2,415	2,105	2,055
OPCo	3,332	3,198	3,339
PSO	1,926	1,781	1,945
SWEPCo	1,853	1,838	1,866

16. STOCK-BASED COMPENSATION

The disclosures in this note apply to AEP only. The impact of AEP's share-based compensation plans is insignificant to the financial statements of the Registrant Subsidiaries.

AEP's long-term incentive plan available for eligible employees and directors, the American Electric Power System 2015 Long-Term Incentive Plan (2015 LTIP), was replaced prospectively for new grants by the American Electric Power System 2024 Long-Term Incentive Plan (2024 LTIP) effective in April 2024. The 2024 LTIP provides for a maximum of 10 million AEP common shares to be available for grant to eligible employees and directors. As of December 31, 2025, 8,909,934 shares remained available for issuance under the 2024 LTIP. No new awards may be granted under the 2015 LTIP. To the extent the issuance of a share is subject to an outstanding award under the 2015 LTIP, the issuance of that share will take place under the 2015 LTIP. Awards granted under the 2024 LTIP may be made in the form of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards. All types of shares issued under the 2024 LTIP including stock options, stock appreciation rights, restricted stock units and performance shares reduce the shares remaining available for grants at a rate of 1 to 1. Cash settled awards do not reduce the number of shares remaining available under the 2024 LTIP. The following sections provide further information regarding each type of stock-based compensation award granted under these plans.

Performance Shares

Performance shares are settled in AEP common stock and reduce the aggregate share authorization. The number of performance shares held at the end of the three-year performance period is multiplied by the performance score for such period to determine the actual number of performance shares that participants realize. The performance score can range from 0% to 200% and is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the Human Resources Committee of AEP's Board of Directors (HR Committee).

Certain employees must satisfy a minimum stock ownership requirement. If those employees have not met their stock ownership requirement, their performance shares are mandatorily deferred upon vesting into AEP career shares to the extent needed to meet their stock ownership requirement. AEP career shares are a form of non-qualified deferred compensation that has a value equivalent to a share of AEP common stock but cannot be sold or transferred and do not have voting rights. AEP career shares are settled in AEP common stock after the participant's termination of employment.

AEP career shares are recorded in Paid-in Capital on the balance sheets. Amounts equivalent to cash dividends on both performance shares and AEP career shares accrue as additional shares. Management records compensation cost for performance shares over an approximately three-year vesting period. Performance shares are recorded as temporary equity on the balance sheets until the vesting date and compensation cost is calculated at fair value based on the performance metrics for each grant. Performance shares granted in 2025 have two performance metrics: (a) three-year cumulative operating earnings per-share with a 50% weight and (b) relative total shareholder return with a 50% weight. Performance shares granted in 2024 and 2023 have three performance metrics: (a) three-year cumulative operating earnings per-share with a 50% weight, (b) relative total shareholder return with a 40% weight and (c) generation capacity additions, which focused on additions that maintain reliability for 2024 grants, and renewable generation additions for 2023 grants. The three-year cumulative operating earnings per-share and generation capacity additions metrics are adjusted quarterly for changes in performance relative to the metric approved by the HR Committee. The total shareholder return metric is measured relative to a peer group of similar companies and is based on a third-party Monte Carlo valuation. The value related to this metric does not change over the three-year vesting period.

The HR Committee awarded performance shares and reinvested dividends on outstanding performance shares and AEP career shares as follows:

Performance Shares	Years Ended December 31, 2025	2024	2023
Awarded Shares (in thousands)	498	441	487
Weighted-Average Share Fair Value at Grant Date	$ 123.42	$ 99.76	$ 98.63
Vesting Period (in years)	3	3	3

Performance Shares and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31, 2025	2024	2023
Awarded Shares (in thousands)	53	66	81
Weighted-Average Fair Value at Grant Date	$ 107.71	$ 91.75	$ 82.02
Vesting Period (in years)	(a)	(a)	(a)

(a) The vesting period for the reinvested dividends on performance shares is equal to the remaining life of the related performance shares. Dividends on AEP career shares vest immediately when the dividend is awarded but are not settled in AEP common stock until after the participant's AEP employment ends.

Performance scores and final awards are determined and approved by the HR Committee in accordance with the pre-established performance measures within approximately two months after the end of the performance period.

The performance scores and shares earned for the three-year periods were as follows:

Performance Shares	Years Ended December 31, 2025 (b)	2024	2023
Performance Score	137.1 %	109.8 %	106.1 %
Performance Shares Earned	477,932	477,487	540,863
Performance Shares Mandatorily Deferred as AEP Career Shares	12,337	39,172	70,377
Performance Shares Voluntarily Deferred into the Incentive Compensation Deferral Program	19,503	21,245	22,716
Performance Shares to be Settled (a)	446,092	417,070	447,770

(a) Performance shares settled in AEP common stock in the quarter following the end of the year shown.
(b) Performance shares earned, deferred and settled were calculated based on the estimated performance score.

The settlements were as follows:

Performance Shares and AEP Career Shares	Years Ended December 31, 2025	2024	2023
		(in millions)	
AEP Common Stock Settlements for Performance Shares	$ 45	$ 38	$ 42
AEP Common Stock Settlements for Career Share Distributions	13	8	8

A summary of the status of AEP's nonvested Performance Shares as of December 31, 2025 and changes during the year ended December 31, 2025 were as follows:

Nonvested Performance Shares	Shares	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2025	778	$ 100.97
Awarded	498	123.42
Dividends	41	107.80
Vested (a)	(353)	100.41
Forfeited	(157)	106.44
Nonvested as of December 31, 2025	807	114.36

(a) The vested Performance Shares will be converted to an estimated 446 thousand shares based on the closing share price on the day before settlement.

Monte Carlo Valuation

AEP engages a third-party for a Monte Carlo valuation to calculate the fair value of the total shareholder return metric for the performance shares awarded during and after 2017. The valuations use a lattice model and the expected volatility assumptions used were the historical volatilities for AEP and the members of their peer group. The assumptions used in the Monte Carlo valuations were as follows:

Assumptions	Years Ended December 31, 2025	2024	2023
Valuation Period (in years) (a)	2.86	2.85	2.87
Expected Volatility Minimum	18.86 %	18.79 %	21.23 %
Expected Volatility Maximum	46.96 %	33.29 %	39.00 %
Expected Volatility Average	23.26 %	22.34 %	25.35 %
Dividend Rate (b)	— %	— %	— %
Risk Free Rate	4.28 %	4.43 %	4.32 %

(a) Period from award date to vesting date.
(b) Equivalent to reinvesting dividends.

Restricted Stock Units and Unrestricted Shares

The HR Committee grants restricted stock units (RSUs), which generally vest, subject to the participant's continued AEP employment, over at least three years in approximately equal annual increments. The RSUs accrue dividends as additional RSUs. The additional RSUs granted as dividends vest on the same date, subject to the participant's continued AEP employment, as the underlying RSUs. RSUs are converted into shares of AEP common stock upon vesting. The RSU compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of RSUs granted by the grant date market closing price. The maximum contractual term of outstanding RSUs is approximately 60 months from the grant date. The HR Committee also occasionally grants unrestricted shares that are immediately vested and paid.

The HR Committee awarded RSUs, including additional units awarded as dividends, and unrestricted shares as follows:

RSUs and Unrestricted Shares	Years Ended December 31, 2025	2024	2023
Awarded RSUs and Granted Unrestricted Shares (in thousands)	440	417	268
Weighted-Average Grant Date Fair Value	$ 105.04	$ 87.85	$ 88.52

The total fair value and total intrinsic value of RSUs vested and unrestricted shares granted were as follows:

RSUs and Unrestricted Shares	Years Ended December 31, 2025	2024	2023
		(in millions)	
Fair Value of RSUs Vested and Unrestricted Shares Granted	$ 22	$ 26	$ 19
Intrinsic Value of RSUs Vested and Unrestricted Shares Granted (a)	26	27	19

(a) Intrinsic value is calculated as market price at the vesting date or, for unrestricted shares, the grant date.

A summary of the status of AEP's nonvested RSUs as of December 31, 2025 and changes during the year ended December 31, 2025 were as follows:

Nonvested RSUs	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2025	477	$ 88.37
Awarded, Including Unrestricted Shares	440	105.04
Vested, Including Unrestricted Shares	(243)	89.63
Forfeited	(76)	90.10
Nonvested as of December 31, 2025	598	100.13

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2025 was $69 million and the weighted-average remaining contractual life was 2.1 years.

Other Stock-Based Plans

AEP also has a Stock Unit Accumulation Plan (SUAP) for Non-Employee Directors providing each non-employee director with AEP stock units as a substantial portion of the compensation for their services as a director. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The stock units granted to non-employee directors are fully vested on their grant date. Stock units are paid to directors upon termination of their board service or up to 10 years later if the participant so elects.

Management records compensation costs for stock units when the units are awarded.

After five years of service on the Board of Directors, non-employee directors receive subsequent AEP stock units as contributions to an AEP stock fund under the Stock Unit Accumulation Plan. Such amounts may be exchanged into other market-based investment options available to employees that participate in AEP's Incentive Compensation Deferral Plan. These balances are paid in cash upon termination of board service or up to 10 years later if the participant so elects.

AEP common stock provided for stock unit distributions were immaterial for the years ended December 31, 2025, 2024 and 2023.

The Board of Directors awarded stock units, including units awarded for dividends, as follows:

	Years Ended December 31,		
Stock Unit Accumulation Plan for Non-Employee Directors	**2025**	**2024**	**2023**
Awarded Units (in thousands)	16	19	20
Weighted-Average Grant Date Fair Value	$ 109.25	$ 91.42	$ 82.14

Share-based Compensation Plans

The compensation cost for share-based payment arrangements, the actual tax benefit from the tax deductions for compensation cost recognized in income and the total compensation cost capitalized were as follows:

	Years Ended December 31,		
Share-based Compensation Plans	**2025**	**2024**	**2023**
		(in millions)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 53	$ 53	$ 51
Actual Tax Benefit	8	7	6
Total Compensation Cost Capitalized	17	14	15

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on the statements of income.

As of December 31, 2025, there was $95 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the 2015 LTIP and the 2024 LTIP. Unrecognized compensation cost related to unvested share-based arrangements will change as the fair value of performance shares is adjusted each period and as forfeitures for all award types are realized. AEP's unrecognized compensation cost will be recognized over a weighted-average period of 1.6 years.

Under the 2015 LTIP and 2024 LTIP, AEP is permitted to use authorized but unissued shares, treasury shares, shares acquired in the open market specifically for distribution under these plans, or any combination thereof to fulfill share commitments. AEP's current practice is generally to use authorized but unissued shares to fulfill share commitments. The number of shares used to fulfill share commitments is generally reduced to offset tax withholding obligations.

17. RELATED PARTY TRANSACTIONS

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

For other related party transactions, also see "Income Taxes and Investment and Production Tax Credits" section of Note 1, "Corporate Borrowing Program" and "Securitized Accounts Receivables – AEP Credit" sections of Note 15 and "Gigawatt AI" section of Note 18.

Intercompany Billings

The Registrant Subsidiaries and other AEP subsidiaries perform certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

Power Coordination Agreement (Applies to all Registrant Subsidiaries except AEP Texas and AEPTCo)

Effective January 1, 2014, the FERC approved the PCA. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective Off-system Sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement. AEPSC conducts only gasoline, diesel fuel, energy procurement and risk management activities on OPCo's behalf.

Joint License Agreement (Applies to all Registrant Subsidiaries except AEP Texas and SWEPCo)

AEPTCo entered into a 50-year joint license agreement with APCo, I&M, KPCo, OPCo and PSO, respectively, allowing either party to occupy the granting party's facilities or real property. In addition, AEPTCo entered into a 5-year joint license agreement with APCo and WPCo. After the expiration of these agreements, the term shall automatically renew for successive one-year terms unless either party provides notice. The joint license billing provides compensation to the granting party for the cost of carrying assets, including depreciation expense, property taxes, interest expense, return on equity and income taxes. AEPTCo recorded the costs related to these agreements in Other Operation expense on the statements of income. APCo, I&M, KPCo, OPCo, PSO and WPCo recorded income related to these agreements in Sales to AEP Affiliates on the statements of income. The impact of the joint license agreement for the years ended December 31, 2025, 2024 and 2023 was not material.

Unit Power Agreements (Applies to I&M)

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the energy and capacity available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all of its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The UPA will continue in effect until the debt obligations of AEGCo secured by the Rockport Plant have been satisfied and discharged (currently expected to be December 2028). I&M's direct purchases from AEGCo were $268 million, $209 million and $181 million for the years ended December 31, 2025, 2024 and 2023, respectively. These direct purchases are presented as Purchased Electricity from AEP Affiliates on I&M's statements of income.

Ohio Auctions (Applies to OPCo)

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. AEP Energy and AEPEP participate in the auction process and have been awarded tranches of OPCo's SSO load. OPCo's auction purchases were $65 million, $98 million and $87 million for the years ended December 31, 2025, 2024 and 2023, respectively. These direct purchases are presented as Purchased Electricity from AEP Affiliates on OPCo's statements of income.

Sales and Purchases of Property

Certain AEP subsidiaries had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions and the net book value of all sales and purchases for the years ended December 31, 2025, 2024 and 2023 were not material. These sales and purchases are recorded in Property, Plant and Equipment on the balance sheets.

Charitable Contributions to AEP Foundation

The AEP Foundation is funded by AEP and its utility operating units. The AEP Foundation provides a permanent, ongoing resource for charitable initiatives and multi-year commitments in the communities served by AEP and initiatives outside of AEP's 11-state service area. The AEP Foundation is not consolidated by AEP. Charitable contributions to the AEP Foundation were not made in 2024 or 2023. Charitable contributions were recorded in Other Operation expenses on the statements of income as follows for the year ended December 31, 2025:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Contributions to AEP Foundation	$ 10	$ 1	$ 2	$ 2	$ 1	$ 1	$ 1	$ 1

Other Related Party Contributions

For the year ended December 31, 2023, AEP made contributions of $80 thousand to Clean Affordable Reliable Coalition (CARE), a 501(c)(6) organization established to encourage communication, discussion and concerted action related to tax policy associated with clean, affordable and reliable power initiatives. These contributions were made in the ordinary course of business. AEP was a member of CARE and provided the organization its primary financial support. In addition, an employee of AEP served as a board member of the organization during 2023. AEP management has determined these contributions are Related Party transactions under ASC 850 based on AEP's ability to significantly influence the management and operating policies of CARE. AEP made no contributions to CARE in 2024 or 2025.

Beginning in August 2024, an officer of AEP also served as a member of the board of directors of a company that is a vendor of certain AEP subsidiaries. From August 2024 through December 2024, AEP purchased $44 million of distribution and transmission infrastructure services from the related party vendor in the ordinary course of business. Of this amount, $25 million was incurred by AEP Texas and $13 million was incurred by PSO. The amounts incurred by the remaining Registrant Subsidiaries were not significant. No amounts were incurred in 2025.

I&M Barging, Urea Transloading and Other Services (Applies to APCo and I&M)

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services in Other Revenues – Affiliated on the statements of income. The affiliated companies recorded these costs paid to I&M as fuel expenses or other operation expenses. The amounts of affiliated expenses were:

	Years Ended December 31,		
Company	**2025**	**2024**	**2023**
		(in millions)	
AEGCo	$ 15	$ 10	$ 9
APCo	36	47	39
WPCo	7	8	11

Competitive Contracted Renewables PPAs (Applies to I&M, OPCo and SWEPCo)

Prior to acquisition, Fowler Ridge 2 had PPAs with I&M and OPCo and Flat Ridge 2 had a PPA with SWEPCo for a portion of their energy production. The amounts of purchased electricity by I&M and OPCo were $8 million and $16 million, respectively, in 2023. See Note 7 - Acquisitions, Dispositions and Impairments for additional information related to the disposal of the 50% interests in Fowler Ridge 2 which was included in the August 2023 sale of the Competitive Contracted Renewables Portfolio.

Transmission Service Charges

The AEP East Companies are parties to the TA, which defines how transmission costs through the PJM OATT are allocated among the AEP East Companies on a 12-month average coincident peak basis. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to AEP East Companies through the PJM OATT. PSO, SWEPCo and AEPSC are parties to the TCA in connection with the operation of the transmission assets of PSO and SWEPCo. Under the TCA, AEPSC is responsible for monitoring the reliability of their transmission systems and administering the OATT. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to PSO and SWEPCo through the SPP OATT. Pursuant to an order from the PUCT, ETT bills AEP Texas for its ERCOT wholesale transmission services.

The charges discussed above are recorded in Other Operation expenses on the statements of income. AEPTCo recorded affiliated transmission revenues in Sales to AEP Affiliates on the statements of income. Refer to the Affiliated Revenues section below for amounts related to these transactions.

The following table shows the net transmission service charges recorded by the Registrant Subsidiaries:

	Years Ended December 31,		
Company	**2025**	**2024**	**2023**
		(in millions)	
AEP Texas	$ 31	$ 31	$ 29
APCo	440	381	365
I&M	269	253	226
OPCo	789	696	665
PSO	171	127	100
SWEPCo	84	65	49

Affiliated Revenues

The tables below represent revenues from affiliates, net of respective provisions for refund, by type of revenue for the Registrant Subsidiaries. Related party revenues are shown in Sales to AEP Affiliates, Provision for Refund - Affiliated and Other Revenues - Affiliated, respectively, on the Registrant Subsidiaries' statements of income.

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2025							
Direct Sales to East Affiliates	$ —	$ —	$ 165	$ —	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—	—	—	—	4	—
Transmission Revenues	—	1,848	99	(1)	13	—	81
Other Revenues	5	21	15	70	32	5	2
Total Affiliated Revenues	$ 5	$ 1,869	$ 279	$ 69	$ 45	$ 9	$ 83

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2024							
Direct Sales to East Affiliates	$ —	$ —	$ 159	$ —	$ —	$ —	$ —
Transmission Revenues	—	1,491	79	(9)	(7)	—	61
Other Revenues	5	21	10	75	30	7	1
Total Affiliated Revenues	$ 5	$ 1,512	$ 248	$ 66	$ 23	$ 7	$ 62

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2023							
Direct Sales to East Affiliates	$ —	$ —	$ 159	$ —	$ —	$ —	$ —
Transmission Revenues	—	1,304	71	(11)	3	—	45
Barging, Urea Transloading and Other Transportation Services	—	—	—	59	—	—	—
Other Revenues	5	13	9	9	28	1	2
Total Affiliated Revenues	$ 5	$ 1,317	$ 239	$ 57	$ 31	$ 1	$ 47

18. 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 nonconsolidated VIEs are accounted for under the equity method of accounting.

Consolidated Variable Interests Entities

Sabine (Applies to AEP and SWEPCo)

Sabine is a mining operator whose purpose was to provide mining services to SWEPCo's Pirkey Plant until its retirement in March 2023. Sabine's post-production operations primarily consist of reclamation and other land-related activities. The terms of these services are governed by a lignite mining agreement between SWEPCo and Sabine. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements with Sabine's creditors, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the lignite mining agreement, SWEPCo is required to pay an amount equal to Sabine's operating costs plus a management fee and SWEPCo holds an option agreement to purchase Sabine, which SWEPCo exercised in 2023. As a result, SWEPCo will take direct control over reclamation activities in October 2026. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's balance sheets.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $155 million. Since SWEPCo uses self-bonding, the guarantee commits SWEPCo to complete the reclamation, in the event, Sabine does not complete the work. This guarantee ends upon completion of reclamation activities expected by 2037 with an estimated cost of $68 million. Actual costs may vary due to inflation and changes in reclamation scope. SWEPCo recovers these costs through its fuel clauses. As of December 31, 2025, SWEPCo has recorded an ARO of $66 million and has paid or accrued $113 million for reclamation costs billed by Sabine. To date, SWEPCo has collected $102 million from customers for reclamation costs and expects to collect an additional $77 million recorded in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

DCC Fuel (Applies to AEP and I&M)

I&M has nuclear fuel lease agreements with DCC Fuel, which was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each DCC Fuel entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2025, 2024 and 2023 were $119 million, $111 million and $97 million, respectively. The leases qualify as finance leases because title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on I&M's control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The finance leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on I&M's balance sheets.

Restoration Funding (Applies to AEP and AEP Texas)

Restoration Funding was formed for the sole purpose of issuing and servicing securitization bonds related to storm restoration of AEP Texas' distribution system primarily due to damage caused by Hurricane Harvey. Management concluded that AEP Texas is the primary beneficiary of Restoration Funding because AEP Texas has the power to direct the most significant activities of the VIE and AEP Texas' equity interest could potentially be significant. Therefore, AEP Texas is required to consolidate Restoration Funding. As of December 31, 2025 and 2024, $25 million and $24 million of the securitized bonds were included in Long-term Debt Due Within One Year - Nonaffiliated, respectively, and $78 million and $102 million were included in Long-term Debt - Nonaffiliated, respectively, on the balance sheets. Restoration Funding's securitized assets were $94 million and $117 million as of December 31, 2025 and 2024, respectively, which are presented separately on the face of the balance sheets.

The securitized restoration assets represent the right to impose and collect Texas storm restoration costs from customers receiving electric transmission or distribution service from AEP Texas under-recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to AEP Texas or any other AEP entity. AEP Texas acts as the servicer for Restoration Funding's securitized assets and remits all related amounts collected from customers to Restoration Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Restoration Funding's assets and liabilities on the balance sheets.

Appalachian Consumer Rate Relief Funding (Applies to AEP and APCo)

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. As of December 31, 2025 and 2024, $30 million and $28 million of the securitized bonds were included in Long-term Debt Due Within One Year - Nonaffiliated, respectively, and $62 million and $91 million were included in Long-term Debt - Nonaffiliated, respectively, on the balance sheets. Appalachian Consumer Rate Relief Funding's securitized assets were $78 million and $106 million as of December 31, 2025 and 2024, respectively, which are presented separately on the face of the balance sheets.

The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on APCo's balance sheets.

Storm Recovery Funding (Applies to AEP and SWEPCo)

Storm Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to storm recovery primarily related to SWEPCo's distribution system. Management concluded that SWEPCo is the primary beneficiary of Storm Recovery Funding because SWEPCo has the power to direct the most significant activities of the VIE and SWEPCo's equity interest could potentially be significant. Therefore, SWEPCo is required to consolidate Storm Recovery Funding. As of December 31, 2025 and 2024, $17 million and $23 million of the securitized bonds were included in Long-term Debt Due Within One Year - Nonaffiliated, respectively, and $304 million and $309 million were included in Long-term Debt - Nonaffiliated, respectively, on the balance sheets. Storm Recovery Funding's securitized assets were $315 million and $331 million as of December 31, 2025 and 2024, respectively, which are presented separately on the face of the balance sheets.

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

Cost Recovery Funding (Applies to AEP)

In June 2025, Cost Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to plant retirement costs, deferred storm costs related to 2020, 2021, 2022 and 2023 major storms, deferred purchased power expenses, under-recovered purchased power rider costs and issuance-related expenses, including KPSC advisor expenses. Management concluded that KPCo is the primary beneficiary of Cost Recovery Funding because KPCo has the power to direct the most significant activities of the VIE and KPCo's equity interest could potentially be significant. Therefore, KPCo is required to consolidate Cost Recovery Funding. As of December 31, 2025, $16 million of the securitized bonds was included in Long-term Debt Due Within One Year and $453 million was included in Long-term Debt on the balance sheet. Cost Recovery Funding's securitized assets were $462 million as of December 31, 2025, which was presented separately on the face of the balance sheet.

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

AEP Credit (Applies to AEP)

AEP Credit is a wholly-owned subsidiary of Parent. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 35% of AEP Credit's short-term borrowing needs in excess of third-party financings. Any third-party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on AEP's control of AEP Credit, management concluded that AEP is the primary beneficiary and is required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the balance sheets. See "Securitized Accounts Receivables - AEP Credit" section of Note 15.

EIS (Applies to AEP)

AEP's subsidiaries participate in one protected cell of EIS for seven lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third-parties access to this insurance. AEP's subsidiaries and any allowed third-parties share in the insurance coverage, premiums and risk of loss from claims. Based on AEP's control and the structure of the protected cell of EIS, management concluded that AEP is the primary beneficiary of the protected cell and is required to consolidate the protected cell of EIS. The insurance premium expense to the protected cell for the years ended December 31, 2025, 2024 and 2023 was $39 million, $37 million and $34 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

Transource Energy (Applies to AEP)

Transource Energy was formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates. AEP has an 86.5% equity and voting ownership interest and the remaining 13.5% interest is held by a single third-party owner. Management concluded that Transource Energy is a VIE and that AEP is the primary beneficiary because AEP has the power to direct the most significant activities of the entity and AEP's equity interest could potentially be significant. Therefore, AEP is required to consolidate Transource Energy. Transource Energy's activities consist of the development, construction and operation of FERC-regulated transmission assets in Missouri, West Virginia, Pennsylvania, Maryland and Oklahoma. Transource Energy has a credit facility agreement where borrowings are loaned through intercompany lending agreements to its subsidiaries. The creditor to the agreement has no recourse to the general credit of AEP. Transource Energy's credit facility agreement contains certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. See the tables below for the classification of Transource Energy's assets and liabilities on the balance sheets.

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

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.

December 31, 2024

	Consolidated VIEs							
	SWEPCo Sabine	I&M DCC Fuel	AEP Texas Restoration Funding	APCo Appalachian Consumer Rate Relief Funding	SWEPCo Storm Recovery Funding	AEP Credit	Protected Cell of EIS	Transource Energy
	(in millions)							
ASSETS								
Current Assets	$ 6	$ 79	$ 21	$ 14	$ 3	$ 1,118	$ 219	$ 40
Net Property, Plant and Equipment	—	132	—	—	—	—	—	598
Other Noncurrent Assets	111	64	122 (a)	110 (b)	332	11	—	4
Total Assets	$ 117	$ 275	$ 143	$ 124	$ 335	$ 1,129	$ 219	$ 642
LIABILITIES AND EQUITY								
Current Liabilities	$ 20	$ 79	$ 31	$ 31	$ 24	$ 1,069	$ 55	$ 57
Noncurrent Liabilities	96	196	111	91	309	1	96	274
Equity	1	—	1	2	2	59	68	311
Total Liabilities and Equity	$ 117	$ 275	$ 143	$ 124	$ 335	$ 1,129	$ 219	$ 642

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

Non-Consolidated Significant Variable Interests - AEP

AEPSC (Applies to Registrant Subsidiaries)

AEPSC, a wholly-owned subsidiary of Parent, is consolidated by AEP. Parent is the sole equity owner of AEPSC and controls the activities of AEPSC. AEPSC provides certain managerial and professional services to AEP's subsidiaries. The costs of the services are based on a direct-charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant variable interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

	Years Ended December 31,		
Company	**2025**	**2024**	**2023**
		(in millions)	
AEP Texas	$ 278	$ 243	$ 229
AEPTCo	319	290	270
APCo	352	335	325
I&M	189	188	178
OPCo	282	283	270
PSO	176	157	139
SWEPCo	207	194	185

The carrying amount and classification of variable interest in AEPSC's accounts payable were as follows:

	December 31,			
	2025		**2024**	
Company	**As Reported on the Balance Sheet**	**Maximum Exposure**	**As Reported on the Balance Sheet**	**Maximum Exposure**
		(in millions)		
AEP Texas	$ 51	$ 51	$ 26	$ 26
AEPTCo	54	54	29	29
APCo	52	52	36	36
I&M	32	32	25	25
OPCo	47	47	35	35
PSO	29	29	19	19
SWEPCo	32	32	22	22

AEGCo (Applies to I&M)

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Units 1 and 2. AEGCo sells its portion of the output from the Rockport Plant to I&M. AEP has agreed to provide AEGCo with the funds necessary to satisfy all the debt obligations of AEGCo. I&M is considered to have a significant variable interest in AEGCo due to these transactions. I&M is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. In the event AEGCo requires financing or other support outside the billings to I&M, it would be provided by AEP. AEGCo's billings to I&M for the years ended December 31, 2025, 2024 and 2023 were $268 million, $209 million and $181 million, respectively. The carrying amounts of I&M's liabilities associated with AEGCo as of December 31, 2025 and 2024 were $19 million and $14 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liabilities.

AEP Development Services (Applies to OPCo)

AEP Development Services, LLC (Devco), a wholly-owned subsidiary of Parent, is consolidated by AEP. Devco was formed for the purpose of developing, constructing and installing energy projects for the regulated operating companies across the AEP system. In the fourth quarter of 2024, Devco executed a purchase agreement with Bloom Energy, acquiring 100 MWs of solid oxide fuel cells. Devco contemporaneously executed an affiliated services agreement with OPCo to establish the terms and conditions for Devco to design, procure, construct and ultimately sell customer-sited, behind-the-meter fuel cell generation facilities to OPCo. Sales of fuel cell generation facilities will be made for OPCo to meet its obligations arising from bilateral customer-sited renewable energy resource agreements (CSRERAs) entered with its commercial customers. Sales are generally expected to close when a fuel cell generation facility is mechanically complete and will be sold at net book value plus reimbursement for the costs of Devco's services. OPCo will own and operate the fuel cell generation facilities, and sell power produced by them to its customers under the terms of the applicable CSRERAs.

Devco is a VIE because its operations and activities, including the initial 100 MWs purchase of fuel cells from Bloom Energy, are entirely financed by Parent through borrowings from the Nonutility Money Pool. Parent controls the significant activities of Devco and is exposed to its potential losses to the extent sales of completed fuel cell generation facilities to OPCo are insufficient to cover its costs of operations. AEP intends to recover its investment through the fulfillment of contractual commitments to deploy and install fuel cells to provide electricity service to customers. Based on AEP's control of Devco, management concluded that AEP is the primary beneficiary and is required to consolidate Devco. In addition, OPCo has a noncontrolling variable interest in Devco because of the pricing structure for the sales of fuel cell generation facilities. As of December 31, 2025 and 2024, the amounts of CWIP were $480 million and $457 million, respectively, and borrowings from the Nonutility Money Pool were $485 million and $456 million, respectively, on the balance sheets.

Non-Consolidated Significant Variable Interests - Registrant Subsidiaries

DHLC (Applies to AEP and SWEPCo)

DHLC is a mining operator which previously sold 50% of the lignite produced to SWEPCo and 50% to CLECO. The operations of DHLC are governed by the lignite mining agreement among SWEPCo, CLECO and DHLC. SWEPCo and CLECO share the executive board seats and voting rights equally. In accordance with the lignite mining agreement, each entity is responsible for 50% of DHLC's obligations, including debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee earned by DHLC. In April 2020, SWEPCo and CLECO jointly filed a notification letter to the LPSC providing notice of the cessation of lignite mining. SWEPCo's total billings from DHLC for the years ended December 31, 2025, 2024 and 2023 were not material. DHLC paid dividends of $1 million, $1 million, and $1 million to SWEPCo for the years ended December 31, 2025, 2024 and 2023, respectively. SWEPCo does not have the power to control decision making that significantly impacts the economic performance of DHLC because such power is shared with CLECO. As a result, SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although it holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

SWEPCo's investment in DHLC was:

	December 31,			
	2025		2024	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 7	$ 7	$ 7	$ 7
Retained Earnings	1	1	1	1
SWEPCo's Share of Obligations	—	11	—	16
Total Investment in DHLC	$ 8	$ 19	$ 8	$ 24

OVEC (Applies to AEP and OPCo)

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2025, AEP's ownership in OVEC was 43.47%. Parent owns 39.17% and OPCo owns 4.3%. APCo, I&M and OPCo are members to an intercompany power agreement. The Registrants' power participation ratios are 15.69% for APCo, 7.85% for I&M and 19.93% for OPCo. Participants of this agreement are entitled to receive and are obligated to pay for all OVEC generating capacity, approximately 2,400 MWs, in proportion to their respective power participation ratios. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, including outstanding indebtedness, and provide a return on capital. The intercompany power agreement ends in June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests. OVEC financed capital expenditures in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at its two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2025 and 2024, OVEC's outstanding indebtedness was approximately $873 million and $997 million, respectively. Although they are not an obligor or guarantor, the Registrants' are responsible for their respective ratio of OVEC's outstanding debt through the intercompany power agreement. Principal and interest payments related to OVEC's outstanding indebtedness are disclosed in accordance with the accounting guidance for "Commitments." See the "Commitments" section of Note 6 for additional information.

AEP is not required to consolidate OVEC as it is not the primary beneficiary, although AEP and OPCo each hold a significant variable interest in OVEC. Power to control decision making that significantly impacts the economic performance of OVEC is shared amongst the owners through their representation on the Board of Directors of OVEC and the representation of the sponsoring companies on the Operating Committee under the intercompany power agreement.

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. Upon completion of the transaction, Parent will remain responsible for the financial and other obligations of AGR under the intercompany power agreement. In December 2025, the PUCO approved the application and a decision from the FERC is expected in the first half of 2026.

AEP's investment in OVEC was:

	December 31,			
	2025		2024	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 5	$ 5	$ 5	$ 5
AEP's Share of OVEC Debt (a)	—	379	—	433
Total Investment in OVEC	$ 5	$ 384	$ 5	$ 438

(a) Based on the Registrants' power participation ratios, APCo, I&M and OPCo's share of OVEC debt was $137 million, $68 million and $174 million as of December 31, 2025, respectively, and $156 million, $78 million and $199 million as of December 31, 2024, respectively.

Power purchased by the Registrant Subsidiaries from OVEC is included in Purchased Electricity, Fuel and Other Consumables Used for Electric Generation and Purchased Electricity for Resale on the statements of income and is shown in the table below:

	Years Ended December 31,		
Company	2025	2024	2023
	(in millions)		
APCo	$ 120	$ 134	$ 122
I&M	60	67	61
OPCo	153	170	155

Equity Method Investments in Unconsolidated Entities (Applies to AEP)

For a discussion of the equity method of accounting, see the “Equity Method Investments in Unconsolidated Entities” section of Note 1.

ETT

ETT designs, acquires, constructs, owns and operates certain transmission facilities in ERCOT. BHE, a nonaffiliated entity, holds a 50% membership interest in ETT and AEP Transmission Holdco holds a 50% membership interest in ETT. As a result, AEP, through its wholly-owned subsidiary, holds a 50% membership interest in ETT. As of December 31, 2025 and 2024, AEP’s investment in ETT was $969 million and $897 million, respectively. AEP’s equity earnings associated with ETT were $80 million, $86 million and $74 million for the years ended December 31, 2025, 2024 and 2023, respectively.

Gigawatt AI

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 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. Contingent upon GWAI’s achievement of defined performance-based milestones, AEP will invest up to an additional $100 million for up to an additional 10% of GWAI’s common stock. In January 2026, AEP made an additional $25 million investment for an incremental 2.5% interest in GWAI’s common stock because of GWAI’s achievement of a performance-based milestone. 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 $100 million 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 December 31, 2025, AEP’s carrying value of the investment in GWAI was $100 million, which was initially recognized at cost in Deferred Charges and Other Noncurrent Assets on the balance sheet. AEP’s proportionate share of GWAI’s losses was immaterial for the year ended December 31, 2025.

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 December 31, 2025.

19. PROPERTY, PLANT AND EQUIPMENT

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

Property, Plant and Equipment is shown functionally on the face of the balance sheets. The following tables include the total plant balances as of December 31, 2025 and 2024:

December 31, 2025	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo	
					(in millions)					
Regulated Property, Plant and Equipment										
Generation	$ 28,252	(a)	$ —	$ —	$ 7,886	$ 5,415	$ —	$ 4,365	$ 6,621	(a)
Transmission	42,557		8,229	16,542	5,277	2,055	3,916	1,433	3,302	
Distribution	33,364		6,835	—	5,938	3,823	7,661	3,987	3,242	
Other	7,731		1,236	571	1,127	1,011	1,277	1,289	726	
CWIP	7,613	(a)	1,766	2,005	802	397	811	635	712	(a)
Less: Accumulated Depreciation	27,879		2,204	1,915	6,360	4,829	2,992	2,749	3,288	
Total Regulated Property, Plant and Equipment - Net	91,638		15,862	17,203	14,670	7,872	10,673	8,960	11,315	
Nonregulated Property, Plant and Equipment - Net	736		2	—	43	72	11	4	26	
Total Property, Plant and Equipment - Net	$ 92,374		$ 15,864	$ 17,203	$ 14,713	$ 7,944	$ 10,684	$ 8,964	$ 11,341	

December 31, 2024	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo	
					(in millions)					
Regulated Property, Plant and Equipment										
Generation	$ 24,695	(a)	$ —	$ —	$ 7,273	$ 5,439	$ —	$ 2,772	$ 5,288	(a)
Transmission	38,871		7,547	14,913	5,001	1,958	3,664	1,345	2,864	
Distribution	31,062		6,250	—	5,569	3,535	7,244	3,699	3,007	
Other	6,545		1,173	516	1,023	947	1,245	547	683	
CWIP	6,322	(a)	1,118	1,965	743	330	691	379	627	(a)
Less: Accumulated Depreciation	25,794		2,046	1,578	6,031	4,607	2,883	2,215	3,049	
Total Regulated Property, Plant and Equipment - Net	81,701		14,042	15,816	13,578	7,602	9,961	6,527	9,420	
Nonregulated Property, Plant and Equipment - Net	715		2	—	35	77	10	5	26	
Total Property, Plant and Equipment - Net	$ 82,416		$ 14,044	$ 15,816	$ 13,613	$ 7,679	$ 9,971	$ 6,532	$ 9,446	

(a) AEP and SWEPCo's regulated generation and regulated CWIP include amounts related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.

Depreciation, Depletion and Amortization

The Registrants provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide total regulated annual composite depreciation rates and depreciable lives for the Registrants:

AEP

	2025		2024		2023	
Functional Class of Property	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges (in years)**
Generation	2.3% - 5.0%	20 - 162	2.7% - 4.9%	20 - 162	2.7% - 4.7%	20 - 162
Transmission	1.8% - 2.7%	15 - 79	2.1% - 2.7%	15 - 79	2.0% - 2.7%	15 - 78
Distribution	2.7% - 3.4%	7 - 85	2.8% - 3.5%	7 - 85	2.9% - 3.6%	7 - 85
Other	1.5% - 8.7%	5 - 75	3.0% - 8.9%	5 - 75	3.8% - 9.1%	5 - 75

AEP Texas

	2025		2024		2023	
Functional Class of Property	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**
Transmission	2.3%	50 - 79	2.2%	50 - 79	2.2%	50 - 75
Distribution	2.7%	15 - 74	2.8%	15 - 74	2.9%	7 - 70
Other	5.8%	5 - 54	5.9%	5 - 54	6.0%	5 - 50

AEPTCo

	2025		2024		2023	
Functional Class of Property	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**
Transmission	2.7%	24 - 78	2.7%	24 - 78	2.6%	24 - 78
Other	7.4%	5 - 58	7.1%	5 - 58	7.0%	5 - 58

APCo

	2025		2024		2023	
Functional Class of Property	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**
Generation	3.0%	20 - 162	3.2%	35 - 162	3.3%	35 - 162
Transmission	2.3%	15 - 78	2.3%	15 - 78	2.3%	15 - 78
Distribution	3.3%	15 - 60	3.5%	12 - 60	3.6%	12 - 60
Other	6.6%	5 - 55	6.8%	5 - 55	7.4%	5 - 55

I&M

	2025		2024		2023	
Functional Class of Property	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**
Generation	5.0%	20 - 132	4.9%	20 - 132	4.7%	20 - 132
Transmission	2.6%	44 - 67	2.6%	44 - 67	2.5%	44 - 67
Distribution	2.7%	15 - 76	2.8%	15 - 76	2.9%	14 - 71
Other	8.7%	5 - 45	8.9%	5 - 45	9.1%	5 - 45

OPCo

	2025		2024		2023	
Functional Class of Property	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**
Transmission	2.3%	39 - 60	2.3%	39 - 60	2.3%	39 - 60
Distribution	2.9%	11 - 70	3.1%	11 - 70	3.1%	11 - 70
Other	6.0%	5 - 50	5.9%	5 - 50	6.4%	5 - 50

PSO

Functional Class of Property	2025 Annual Composite Depreciation Rate	2025 Depreciable Life Ranges (in years)	2024 Annual Composite Depreciation Rate	2024 Depreciable Life Ranges (in years)	2023 Annual Composite Depreciation Rate	2023 Depreciable Life Ranges (in years)
Generation	2.3%	30 - 78	3.3%	30 - 78	3.0%	25 - 75
Transmission	2.6%	41 - 75	2.6%	41 - 75	2.6%	41 - 75
Distribution	2.8%	15 - 85	2.8%	15 - 85	2.9%	15 - 85
Other	6.8%	5 - 58	6.6%	5 - 58	6.8%	5 - 58

SWEPCo

Functional Class of Property	2025 Annual Composite Depreciation Rate	2025 Depreciable Life Ranges (in years)	2024 Annual Composite Depreciation Rate	2024 Depreciable Life Ranges (in years)	2023 Annual Composite Depreciation Rate	2023 Depreciable Life Ranges (in years)
Generation	3.4%	30 - 65	3.7%	30 - 65	2.9%	30 - 65
Transmission	2.1%	46 - 70	2.2%	46 - 70	2.2%	46 - 70
Distribution	2.9%	7 - 75	2.9%	7 - 75	2.9%	7 - 75
Other	6.9%	5 - 58	6.7%	5 - 58	8.5%	5 - 58

The following table includes the nonregulated annual composite depreciation rate ranges and nonregulated depreciable life ranges for AEP. With the exception of I&M, the Registrants' depreciation rate ranges and depreciable life ranges are not meaningful for nonregulated property for 2025, 2024 and 2023.

Functional Class of Property	2025 Annual Composite Depreciation Rate Ranges (a)	2025 Depreciable Life Ranges (a) (in years)	2024 Annual Composite Depreciation Rate Ranges (a)	2024 Depreciable Life Ranges (a) (in years)	2023 Annual Composite Depreciation Rate Ranges	2023 Depreciable Life Ranges (in years)
Generation	1.9% - 7.6%	39 - 61	1.8% - 6.0%	39 - 61	4.8% - 6.7%	10 - 61
Transmission	NA	NA	NA	NA	2.5%	62
Distribution	NA	NA	NA	NA	NA	NA
Other	10.3%	5 - 35	9.7%	5 - 35	10.6%	5 - 35

(a) I&M's annual composite depreciation rate for Generation property is 1.9% and the depreciable life is 39 years.
NA Not applicable.

For regulated operations, the composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to Accumulated Depreciation and Amortization on the balance sheets. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (Applies to all Registrants except AEPTCo)

Listed below are significant changes to the Registrants ARO balances as of December 31, 2025 and 2024:

- In April 2024, the Federal EPA finalized revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land. In the second quarter of 2024, AEP evaluated the applicability of the rule to current and former plant sites and incurred ARO liabilities of $602 million and revised cash flow estimates by an additional $72 million based on initial cost estimates. See the "Federal EPA's Revised CCR Rule" section of Note 6 for additional information.
- In December 2024, I&M recorded a $176 million revision as a result of the completion of the latest Cook Plant nuclear decommissioning study. I&M's ARO related to nuclear decommissioning costs for the Cook Plant was $2.1 billion and $2 billion as of December 31, 2025 and 2024. As of December 31, 2025 and 2024, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $4.5 billion and $4 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's balance sheets.

The following is a reconciliation of the 2025 and 2024 aggregate carrying amounts of ARO by Registrant:

Company	ARO as of December 31, 2024	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of December 31, 2025
			(in millions)			
AEP(b)(c)(d)(e)(f)(g)	$ 3,612	$ 170	$ 45	$ (103)	$ (12)	$ 3,712
AEP Texas (e)	4	—	—	—	—	4
APCo (b)(e)(f)(g)	802	42	4	(19)	(51)	778
I&M (b)(c)(e)	2,094	86	—	(2)	4	2,182
OPCo (b)(e)	56	4	—	(1)	1	60
PSO (b)(e)(f)(g)	122	8	19	(3)	(3)	143
SWEPCo (b)(d)(e)(f)(g)	279	16	20	(65)	40	290

Company	ARO as of December 31, 2023	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of December 31, 2024
			(in millions)			
AEP (b)(c)(d)(e)(f)	$ 3,031	$ 140	$ 612	$ (102)	$ (69)	$ 3,612
AEP Texas (e)	5	—	—	(1)	—	4
APCo (b)(e)(f)	464	28	247	(18)	81	802
I&M (b)(c)(e)	2,106	80	86	(2)	(176)	2,094
OPCo (b)(e)	2	1	53	—	—	56
PSO (b)(e)(f)	84	6	34	(2)	—	122
SWEPCo (b)(d)(e)(f)	282	16	30	(69)	20	279

(a) Unless discussed above, primarily related to ash ponds, landfills and mine reclamation, generally due to changes in estimated closure area, volumes and/or unit costs.
(b) Includes ARO related to ash disposal facilities.
(c) Includes ARO related to nuclear decommissioning costs for the Cook Plant.
(d) Includes ARO related to Sabine and DHLC.
(e) Includes ARO related to asbestos removal.
(f) Includes ARO related to renewables.
(g) Includes ARO related to incurred ARO liabilities due to the acquisitions in 2025. See the "Acquisitions" section of Note 7 for additional information.

Allowance for Funds Used During Construction and Interest Capitalization

The Registrants' amounts of allowance for equity funds used during construction are summarized in the following table:

Company	Years Ended December 31, 2025	2024	2023
		(in millions)	
AEP	$ 245	$ 211	$ 175
AEP Texas	53	46	28
AEPTCo	93	89	83
APCo	17	16	12
I&M	18	13	11
OPCo	25	23	17
PSO	11	7	8
SWEPCo	23	14	11

The Registrants' amounts of allowance for borrowed funds used during construction, including capitalized interest, are summarized in the following table:

Company	Years Ended December 31, 2025	2024	2023
		(in millions)	
AEP	$ 154	$ 130	$ 117
AEP Texas	28	31	23
AEPTCo	37	34	31
APCo	10	11	14
I&M	10	9	8
OPCo	13	13	14
PSO	9	10	5
SWEPCo	13	15	10

Jointly-owned Electric Facilities (Applies to AEP, I&M, PSO and SWEPCo)

The Registrants have electric facilities that are jointly-owned with affiliated and nonaffiliated companies. Using its own financing, each participating company is obligated to pay its share of the costs of these jointly-owned facilities in the same proportion as its ownership interest. Each Registrant's proportionate share of the operating costs associated with these facilities is included in its statements of income and the investments and accumulated depreciation are reflected in its balance sheets under Property, Plant and Equipment as follows:

			Registrant's Share as of December 31, 2025		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Flint Creek Generating Station, Unit 1 (a)	Coal	50.0 %	$ 406	$ 2	$ 208
Turk Generating Plant (a)	Coal	73.3 %	1,520	1	381
Total			$ 1,926	$ 3	$ 589
I&M					
Rockport Generating Plant (b)(c)	Coal	50.0 %	$ 1,353	$ 16	$ 1,341
PSO					
North Central Wind Energy Facilities (d)(e)	Wind	45.5 %	$ 912	$ 3	$ 101
SWEPCo					
Flint Creek Generating Station, Unit 1 (a)	Coal	50.0 %	$ 406	$ 2	$ 208
Turk Generating Plant (a)	Coal	73.3 %	1,520	1	381
North Central Wind Energy Facilities (d)(e)	Wind	54.5 %	1,093	4	128
Total			$ 3,019	$ 7	$ 717

			Registrant's Share as of December 31, 2024		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Flint Creek Generating Station, Unit 1 (a)	Coal	50.0 %	$ 404	$ 4	$ 189
Turk Generating Plant (a)	Coal	73.3 %	1,517	1	350
Total			$ 1,921	$ 5	$ 539
I&M					
Rockport Generating Plant (b)(c)	Coal	50.0 %	$ 1,345	$ 11	$ 1,182
PSO					
North Central Wind Energy Facilities (d)(e)	Wind	45.5 %	$ 912	$ 1	$ 78
SWEPCo					
Flint Creek Generating Station, Unit 1 (a)	Coal	50.0 %	$ 404	$ 4	$ 189
Turk Generating Plant (a)	Coal	73.3 %	1,517	1	350
North Central Wind Energy Facilities (d)(e)	Wind	54.5 %	1,094	1	98
Total			$ 3,015	$ 6	$ 637

(a) Operated by SWEPCo.
(b) Operated by I&M
(c) AEGCo owns 50%
(d) Operated by PSO.
(e) PSO and SWEPCo own undivided interests of 45.5% and 54.5% of the NCWF, respectively.

20. REVENUE FROM CONTRACTS WITH CUSTOMERS

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

Disaggregated Revenues from Contracts with Customers

The tables below represent AEP's reportable segment revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Year Ended December 31, 2025						
	VIU	T&D	AEPTHCo	G&M	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 4,969	$ 2,785	$ —	$ —	$ —	$ —	$ 7,754
Commercial Revenues	3,068	1,626	—	—	—	—	4,694
Industrial Revenues (a)	2,718	533	—	—	—	(1)	3,250
Other Retail Revenues	242	60	—	—	—	—	302
Total Retail Revenues	10,997	5,004	—	—	—	(1)	16,000
Wholesale and Competitive Retail Revenues:							
Generation Revenues	1,033	—	—	187	—	—	1,220
Transmission Revenues (b)	533	812	2,275	—	—	(2,017)	1,603
Retail, Trading and Marketing Revenues (c)	—	—	—	2,463	—	(66)	2,397
Total Wholesale and Competitive Retail Revenues	1,566	812	2,275	2,650	—	(2,083)	5,220
Other Revenues from Contracts with Customers (d)	236	259	36	10	137	(196)	482
Total Revenues from Contracts with Customers	12,799	6,075	2,311	2,660	137	(2,280)	21,702
Other Revenues:							
Alternative Revenue Programs (e)	29	51	66	—	—	(85)	61
Other Revenues (f)	(9)	21	—	102	7	(8)	113
Total Other Revenues	20	72	66	102	7	(93)	174
Total Revenues	$ 12,819	$ 6,147	$ 2,377	$ 2,762	$ 144	$ (2,373)	$ 21,876

(a) Amounts include affiliated and nonaffiliated revenues.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for AEP Transmission Holdco were $1.8 billion. The affiliated revenues for Vertically Integrated Utilities were $211 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for Generation & Marketing were $66 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for Corporate and Other were $113 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 affiliated and nonaffiliated revenues. The affiliated revenues for AEP Transmission Holdco were $57 million. The remaining affiliated amounts were immaterial.
(f) Generation & Marketing includes economic hedge activity.

	Year Ended December 31, 2024						
	VIU	**T&D**	**AEPTHCo**	**G&M**	**Corporate and Other**	**Reconciling Adjustments**	**AEP Consolidated**
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 4,562	$ 2,756	$ —	$ —	$ —	$ —	$ 7,318
Commercial Revenues	2,731	1,567	—	—	—	—	4,298
Industrial Revenues (a)	2,659	515	—	—	—	(1)	3,173
Other Retail Revenues	232	56	—	—	—	—	288
Total Retail Revenues	10,184	4,894	—	—	—	(1)	15,077
Wholesale and Competitive Retail Revenues:							
Generation Revenues	748	—	—	103	—	—	851
Transmission Revenues (b)	483	770	1,978	—	—	(1,620)	1,611
Renewable Generation Revenues (a)	—	—	—	23	—	(4)	19
Retail, Trading and Marketing Revenues (c)	—	—	—	2,081	1	(96)	1,986
Total Wholesale and Competitive Retail Revenues	1,231	770	1,978	2,207	1	(1,720)	4,467
Other Revenues from Contracts with Customers (d)	227	198	26	4	185	(214)	426
Total Revenues from Contracts with Customers	11,642	5,862	2,004	2,211	186	(1,935)	19,970
Other Revenues:							
Alternative Revenue Programs (e)	(22)	26	(53)	—	—	(30)	(79)
Other Revenues (a) (f)	(23)	20	—	(166)	(3)	2	(170)
Total Other Revenues	(45)	46	(53)	(166)	(3)	(28)	(249)
Total Revenues	$ 11,597	$ 5,908	$ 1,951	$ 2,045	$ 183	$ (1,963)	$ 19,721

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $1.6 billion and Vertically Integrated Utilities was $177 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $96 million. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Corporate and Other was $137 million. The remaining affiliated amounts were immaterial.

(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

(f) Generation & Marketing includes economic hedge activity.

	Year Ended December 31, 2023						
	VIU	**T&D**	**AEPTHCo**	**G&M**	**Corporate and Other**	**Reconciling Adjustments**	**AEP Consolidated**
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 4,479	$ 2,609	$ —	$ —	$ —	$ —	$ 7,088
Commercial Revenues	2,679	1,497	—	—	—	—	4,176
Industrial Revenues (a)	2,748	642	—	—	—	(1)	3,389
Other Retail Revenues	243	51	—	—	—	—	294
Total Retail Revenues	10,149	4,799	—	—	—	(1)	14,947
Wholesale and Competitive Retail Revenues:							
Generation Revenues	663	—	—	111	—	—	774
Transmission Revenues (b)	444	702	1,749	—	—	(1,418)	1,477
Renewable Generation Revenues (a)	—	—	—	81	—	(7)	74
Retail, Trading and Marketing Revenues (c)	—	—	—	1,836	1	(82)	1,755
Total Wholesale and Competitive Retail Revenues	1,107	702	1,749	2,028	1	(1,507)	4,080
Other Revenues from Contracts with Customers (d)	204	208	17	9	151	(160)	429
Total Revenues from Contracts with Customers	11,460	5,709	1,766	2,037	152	(1,668)	19,456
Other Revenues:							
Alternative Revenue Programs (e)	(35)	(20)	(37)	—	—	(26)	(118)
Other Revenues (a) (f)	25	24	—	(405)	16	(16)	(356)
Total Other Revenues	(10)	4	(37)	(405)	16	(42)	(474)
Total Revenues	$ 11,450	$ 5,713	$ 1,729	$ 1,632	$ 168	$ (1,710)	$ 18,982

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $1.5 billion and Vertically Integrated Utilities was $205 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $82 million. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Corporate and Other was $100 million. The remaining affiliated amounts were immaterial.

(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

(f) Generation & Marketing includes economic hedge activity.

The tables below represent revenues from contracts with customers, net of respective provisions for refund, by type of revenue for the Registrant Subsidiaries:

	Year Ended December 31, 2025						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 758	$ —	$ 1,863	$ 895	$ 2,026	$ 884	$ 856
Commercial Revenues	474	—	775	802	1,151	554	636
Industrial Revenues (a)	161	—	799	603	373	369	403
Other Retail Revenues	43	—	111	5	17	107	12
Total Retail Revenues	1,436	—	3,548	2,305	3,567	1,914	1,907
Wholesale Revenues:							
Generation Revenues (b)	—	—	372	581	—	25	196
Transmission Revenues (c)	717	2,213	175	51	95	46	195
Total Wholesale Revenues	717	2,213	547	632	95	71	391
Other Revenues from Contracts with Customers (d)	41	36	88	114	218	34	38
Total Revenues from Contracts with Customers	2,194	2,249	4,183	3,051	3,880	2,019	2,336
Other Revenues:							
Alternative Revenue Programs (e)	5	70	26	(9)	46	3	18
Other Revenues (a)	—	—	—	(11)	22	—	—
Total Other Revenues	5	70	26	(20)	68	3	18
Total Revenues	$ 2,199	$ 2,319	$ 4,209	$ 3,031	$ 3,948	$ 2,022	$ 2,354

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for APCo were $165 million primarily relating 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 $1.8 billion, $79 million and $75 million, respectively. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for I&M were $70 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.

(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues. Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for AEPTCo were $56 million. The remaining affiliated amounts were immaterial.

	Year Ended December 31, 2024						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 725	$ —	$ 1,772	$ 847	$ 2,031	$ 800	$ 726
Commercial Revenues	467	—	764	605	1,101	510	558
Industrial Revenues (a)	141	—	813	596	374	349	368
Other Retail Revenues	39	—	113	5	17	100	9
Total Retail Revenues	1,372	—	3,462	2,053	3,523	1,759	1,661
Wholesale Revenues:							
Generation Revenues (b)	—	—	305	394	—	9	177
Transmission Revenues (c)	673	1,925	185	41	96	42	172
Total Wholesale Revenues	673	1,925	490	435	96	51	349
Other Revenues from Contracts with Customers (d)	36	26	87	116	162	39	33
Total Revenues from Contracts with Customers	2,081	1,951	4,039	2,604	3,781	1,849	2,043
Other Revenues:							
Alternative Revenue Programs (e)	(1)	(60)	(6)	(8)	27	(3)	(7)
Other Revenues (a)	—	—	—	(24)	20	—	—
Total Other Revenues	(1)	(60)	(6)	(32)	47	(3)	(7)
Total Revenues	$ 2,080	$ 1,891	$ 4,033	$ 2,572	$ 3,828	$ 1,846	$ 2,036

(a) Amounts include affiliated and nonaffiliated revenues.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $159 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $1.6 billion, APCo was $87 million and SWEPCo was $65 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $75 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

	Year Ended December 31, 2023						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 656	$ —	$ 1,613	$ 842	$ 1,954	$ 831	$ 800
Commercial Revenues	415	—	700	575	1,082	539	609
Industrial Revenues (a)	145	—	778	614	497	423	416
Other Retail Revenues	35	—	106	5	15	113	10
Total Retail Revenues	1,251	—	3,197	2,036	3,548	1,906	1,835
Wholesale Revenues:							
Generation Revenues (b)	—	—	288	327	—	12	177
Transmission Revenues (c)	619	1,704	181	39	83	37	151
Total Wholesale Revenues	619	1,704	469	366	83	49	328
Other Revenues from Contracts with Customers (d)	36	16	74	120	172	22	29
Total Revenues from Contracts with Customers	1,906	1,720	3,740	2,522	3,803	1,977	2,192
Other Revenues:							
Alternative Revenue Programs (e)	(4)	(49)	(19)	(11)	(15)	—	(9)
Other Revenues (a)	—	—	—	25	23	—	—
Total Other Revenues	(4)	(49)	(19)	14	8	—	(9)
Total Revenues	$ 1,902	$ 1,671	$ 3,721	$ 2,536	$ 3,811	$ 1,977	$ 2,183

(a) Amounts include affiliated and nonaffiliated revenues.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $159 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $1.4 billion, APCo was $93 million and SWEPCo was $73 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $68 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

Performance Obligations

AEP has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for “Revenue from Contracts with Customers” allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity’s measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. AEP subsidiaries elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for AEP’s subsidiaries are summarized as follows:

Retail Revenues

AEP’s subsidiaries within the Vertically Integrated Utilities and Transmission and Distribution Utilities segments have performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer’s usage requirements.

Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between AEP’s subsidiaries and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice. Payments from REPs are due to AEP Texas within 35 days.

Wholesale Revenues - Generation

AEP's subsidiaries within the Vertically Integrated Utilities and Generation & Marketing segments have performance obligations to sell electricity to wholesale customers from generation assets in PJM, SPP and ERCOT. The performance obligation to deliver electricity from generation assets is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Wholesale generation revenues are variable as they are subject to the customer's usage requirements.

AEP's subsidiaries within the Vertically Integrated Utilities and Generation & Marketing segments also have performance obligations to stand ready in order to promote grid reliability. Stand ready services are sold into PJM's RPM capacity market. RPM entails a base auction and at least three incremental auctions for a specific PJM delivery year, with the incremental auctions spanning three years. The performance obligation to stand ready is satisfied over time and the consideration for which is variable until the occurrence of the final incremental auction, at which point the performance obligation becomes fixed.

Payments from the RTO for stand ready services are typically received within one week from the issuance of the invoice, which is typically issued weekly. Gross margin resulting from generation sales within the Vertically Integrated Utilities segment are primarily subject to margin sharing agreements with customers and vary by state, where the revenues are reflected gross in the disaggregated revenues tables above.

APCo has a performance obligation to supply wholesale electricity to KGPCo through a PPA. The FERC regulates the cost-based wholesale power transactions between APCo and KGPCo. The purchased power agreement includes a component for the recovery of transmission costs under the FERC OATT. The transmission cost component of purchased power is cost-based and regulated by the Tennessee Regulatory Authority. APCo's performance obligation under the purchased power agreement is satisfied over time as KGPCo simultaneously receives and consumes the wholesale electricity. APCo's revenues from the purchased power agreement are presented within the Generation Revenues line in the disaggregated revenues tables above.

Wholesale Revenues - Transmission

AEP's subsidiaries within the Vertically Integrated Utilities, Transmission and Distribution Utilities and AEP Transmission Holdco segments have performance obligations to transmit electricity to wholesale customers through assets owned and operated by AEP subsidiaries. The performance obligation to provide transmission services in PJM, SPP and ERCOT is partially fixed for a period of one year or less. Payments from the RTO for transmission services are typically received within one week from the issuance of the invoice, which is issued monthly for SPP and ERCOT and weekly for PJM.

AEP subsidiaries within the PJM and SPP regions collect revenues through transmission formula rates. The FERC-approved rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations," and are therefore presented as such in the disaggregated revenues tables above. AEP subsidiaries within the ERCOT region collect revenues through a combination of base rates and interim Transmission Costs of Services filings that are approved by the PUCT.

The AEP East Companies are parties to the TA, which defines how transmission costs are allocated among the AEP East Companies on a 12-month average coincident peak basis. PSO, SWEPCo and AEPSC are parties to the TCA by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. AEPTCo is a transmission owner within the PJM and SPP regions providing transmission services to affiliates in accordance with the OATT, TA and TCA. Affiliate revenues as a result of the respective TA and the TCA are reflected as Transmission Revenues in the disaggregated revenues tables above.

Marketing, Competitive Retail and Renewable Revenues

AEP's subsidiaries within the Generation & Marketing segment have performance obligations to deliver electricity to competitive retail and wholesale customers. Performance obligations for marketing and competitive retail are satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are primarily variable as they are subject to customer's usage requirements; however, certain contracts mandate a delivery of a set quantity of electricity at a predetermined price, resulting in a fixed performance obligation.

Payment terms under marketing arrangements typically follow standard Edison Electric Institute and International Swaps and Derivatives Association terms, which call for payment in 20 days. Payments for competitive retail and offtake arrangements for renewable assets range from 15 to 60 days and are dependent on the product sold, location and the creditworthiness of customer. Invoices for marketing arrangements, competitive retail and offtake arrangements for renewable assets are issued monthly.

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 December 31, 2025. Fixed performance obligations primarily include electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. The Registrants elected to apply the exemption to not disclose the value of unsatisfied performance obligations for contracts with an original expected term of one year or less. Due to the annual establishment of revenue requirements, transmission revenues are excluded from the table below. The Registrant Subsidiaries amounts shown in the table below include affiliated and nonaffiliated revenues.

Company	2026	2027-2028	2029-2030	After 2030	Total
			(in millions)		
AEP	$ 85	$ 86	$ 39	$ 16	$ 226
APCo	16	32	23	12	83
I&M	4	9	5	2	20

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 any material contract assets as of December 31, 2025 and 2024.

When the Registrants receive consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheet 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 any material contract liabilities as of December 31, 2025 and 2024.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on the Registrants' balance sheets within the Accounts Receivable - Customers line item. The Registrants' 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 December 31, 2025 and 2024. See "Securitized Accounts Receivable - AEP Credit" section of Note 15 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:

Years Ended December 31,	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
2025	$ 146	$ 113	$ 67	$ 74	$ 22	$ 65
2024	132	84	55	64	13	21

Contract Costs

Contract costs to obtain or fulfill a contract for AEP subsidiaries within the Generation & Marketing segment are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and are neither bifurcated nor reclassified between current and noncurrent assets on the Registrants' balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Other Operation on the Registrants' income statements. The Registrants did not have material contract costs as of December 31, 2025 and 2024.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Headquarters
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-1000
AEP is incorporated in the State of New York.

Stock Exchange Listing - The Company's common stock is traded principally on the NASDAQ Stock Market under the ticker symbol AEP.

Internet Home Page - Information about AEP, including financial documents, Securities and Exchange Commission (SEC) filings, news releases, investor presentations, shareholder information and customer service information, is available on the Company's home page on the Internet at www.AEP.com/investors.

Inquiries Regarding Your Stock Holdings - Registered shareholders (shares that you own, in your name) should contact the Company's transfer agent, listed below, if you have questions about your account, address changes, stock transfer, lost certificates, direct deposits, dividend checks and other administrative matters. You should have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
For overnight deliveries:
Computershare Trust Company, N.A.
150 Royall St.
Suite 101
Canton, MA 02021
Telephone Response Group:1-800-328-6955
Internet address: www.computershare.com/investor
Hearing Impaired #: TDD: 1-800-952-9245

Beneficial Holders - (Stock held in a bank or brokerage account) - When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name, and this is sometimes referred to as "street name" or a "beneficial owner." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, questions about your account should be directed to your broker.

Dividend Reinvestment and Direct Stock Purchase Plan - A Dividend Reinvestment and Direct Stock Purchase Plan is available to all investors. It is an economical and convenient method of purchasing shares of AEP common stock, through initial cash investments, cash dividends and/or additional optional cash purchases. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent or by visiting www.AEP.com/investors/stock.

Financial Community Inquiries - Institutional investors or securities analysts who have questions about the Company should direct inquiries to Darcy Reese, 614-716-2614, dlreese@aep.com; Individual shareholders should contact Rhonda Owens-Paul, 614-716-2819, rkowens-paul@aep.com.

Number of Shareholders - As of February 12, 2026, there were approximately 42,275 registered shareholders and approximately 1,733,057 shareholders holding stock in street name through a bank or broker. There were 541,059,995 shares outstanding as of February 12, 2026.

Form 10-K - Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2025. A copy can be obtained via mail with a written request to AEP Investor Relations, by telephone at 1-800-237-2667 or electronically at rkowens-paul@AEP.com. A copy of our Form 10-K can also be found by visiting www.AEP.com/investors/financial/sec/.

Executive Leadership Team

Name	Age	Office
William J. Fehrman	65	Chair of the Board of Directors, President and Chief Executive Officer
Rob Berntsen	56	Executive Vice President, General Counsel and Secretary
Doug Cannon	49	President - AEP Transmission
Johannes Eckert	58	Executive Vice President and Chief Information & Technology Officer
Kelly J. Ferneau	57	Executive Vice President and Chief Nuclear Officer
Alicia R. Knapp	47	President - Nuclear Development
Trevor I. Mihalik	59	Executive Vice President and Chief Financial Officer
Phillip R. Ulrich	54	Executive Vice President and Chief Human Resources Officer

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