Buchanan

John F. Povilaitis
717 237 4825
john.povilaitis@bipc.com

409 North Second Street
Suite 500
Harrisburg, PA 17101-1357
T 717 237 4800
F 717 233 0852

May 21, 2026

Via E-Filing
Matthew L. Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

Re: Application of Transource Pennsylvania, LLC for All of the Necessary Authority, Approvals and Certificate of Public Convenience to Begin to Offer, Render, Furnish and/or Supply Transmission Service in portions of Franklin County, Pennsylvania Necessary to Operate Transmission Facilities for Project 9A West and for any Other Approvals Necessary
Docket No. A-2026-

Dear Secretary Homsher:

On behalf of Transource Pennsylvania, LLC ("Transource PA"), please find enclosed for filing the Application of Transource Pennsylvania, LLC for All of the Necessary Authority, Approvals and Certificate of Public Convenience to Begin to Offer, Render, Furnish and/or Supply Transmission Service in portions of Franklin County, Pennsylvania Necessary to Operate Transmission Facilities for Project 9A West, and for any Other Approvals Necessary ("CPC Application").

A filing fee of $350.00 for the CPC Application was paid to the Pennsylvania Public Utility Commission ("PaPUC" or "Commission") at the time of the e-filing. The CPC Application filing consists of the CPC Application and Appendices 1 through 8.

Please note that the CPC Application includes Confidential Appendices 4, 5 and 8. Due to their size, the Public Appendices and the Confidential Appendices are being separately uploaded electronically to the PaPUC's ShareFile for large filings.

The Confidential Appendices contain confidential, commercially valuable and proprietary information for which Transource PA requests confidential treatment. Transource PA respectfully requests that Confidential Appendices be maintained by PaPUC under seal.

The enclosed CPC Application, and a separate but related Siting Application also filed today requesting approval for Transource PA to site, own and operate a HV transmission line in Franklin County, Pennsylvania, both relate to the same transmission line Project. In addition, Transource PA has filed a Petition for Exemption from Zoning related to the Project. Accordingly, Transource PA has filed with the Commission a separate Motion for Consolidation and Timely Evaluation and Disposition by the Commission of these three filings due to their interrelated nature.

Copies of this CPC Application filing are being served by certified mail, return receipt requested, on the Parties listed in the attached Certificate of Service. Please contact the undersigned if you have any questions or concerns. Thank you for your attention to this matter.

Very truly yours,

John F. Povilaitis
Counsel for Transource Pennsylvania, LLC

JFP/psm
Enclosures
cc: Certificate of Service
Darren Gill, Bureau of Technical Utility Services (via email)
Deb Becker, Bureau of Technical Utility Services (via email)
JordanVan Order, Bureau of Technical Utility Services (via email)

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of Transource Pennsylvania, LLC for All of the Necessary Authority, Approvals and Certificate of Public Convenience to Begin to Offer, Render, Furnish and/or Supply Transmission Service in portions of Franklin County, Pennsylvania Necessary to Operate Transmission Facilities for Project 9A West; and for any Other Approvals Necessary	:	Docket No. A-2026-_____

APPLICATION OF TRANSOURCE PENNSYLVANIA, LLC

TO THE PENNSYLVANIA PUBLIC UTILITY COMMISSION:

V. INTRODUCTION

1. By this Application, Transource Pennsylvania, LLC ("Transource PA" or the "Applicant") requests all necessary authority, approvals and certificates of public convenience ("CPC") from the Pennsylvania Public Utility Commission ("PUC" or "Commission"), pursuant to Section 1101 (governing the issuance of certificates of public convenience for public utilities to begin to render service in territory in which they do not possess such authorization) of the Public Utility Code ("Code"), 66 Pa. C.S. §§1101, to commence the provision of transmission electric service as a public utility in portions of Franklin County, Pennsylvania. Collectively, this Application, along with the attachments contained herein, are referred to as the "CPC Application." This CPC Application satisfies the requirements of 52 Pa. Code §5.12 (Contents of applications).

2. Simultaneously with this CPC Application, Transource PA is filing a separate but related Application ("Siting Application") seeking the Commission's approval of the siting and construction of a proposed new electric substation ("Rice Substation") and double-circuit Rice-

Ringgold 230 kilovolt ("kV") electric transmission line and related facilities in portions of Franklin County, Pennsylvania (collectively, the "9A West Project")[1]. In addition to this CPC Application and the Siting Application, Transource PA is simultaneously filing with the Commission a Petition for Confirmation of an Exemption from Local Zoning Regulation and for the Construction of Buildings ("Zoning Petition").

3. The complete name and address of the Applicant is:

Transource Pennsylvania, LLC
1 Riverside Plaza
Columbus, Ohio 43215-2372
Attention: Crystal L. Wood-Hython, Project MGR Staff Sr.

4. The attorneys for the Applicant are:

John F. Povilaitis (PA ID No. 28944)
Alan M. Seltzer (PA ID No. 27890)
409 N. Second Street, Suite 500
Harrisburg, PA 17101
Phone: (717) 237-4800
Fax: (717) 233-0852
E-mail: john.povilaitis@bipc.com
E-mail: alan.seltzer@bipc.com

Jessica A. Cano (FL ID. No. 37372)
American Electric Power Service Corporation
1 Riverside Plaza, 29th Floor
Columbus, OH 43215
Phone: 614-716-2921
Fax: 614-716-1613
E-mail: jacano@aep.com

5. The Applicant's attorneys are authorized to receive all notices and communications regarding the Application.

[1]The municipalities impacted by the 9A West Project are described in more detail in Attachment 4 to Transource PA's Siting Application.

VI. ORGANIZATION OF APPLICATION

6. This Application is organized as follows:

- Section III. provides a description of Transource PA, and other entities related to Transource PA;
- Section IV. provides a description of and the need for the 9A West Project, and the process before PJM that has preceded the filing of the CPC Application;
- Section V. sets forth the legal standards applicable to the granting of a CPC by this Commission;
- Section VI. demonstrates that Transource PA satisfies all legal requirements necessary for the granting of a CPC including that the proposed transmission service will be to or for the public;
- Section VII. confirms that Transource PA will have no retail customers and that no Transource PA rates will be subject to Commission jurisdiction;
- Section VIII. sets forth other required regulatory approvals other than those being requested in this CPC Application;
- Section IX. sets forth Transource PA's request for consolidation of related proceedings and expedited consideration;
- Section X. sets forth the parties to whom notice of the CPC Application is being given; and
- Section XI. sets forth the conclusion and summarizes the relief/approvals requested in the CPC Application.

7. Transource PA submits, as explained in greater detail below, that all legal requirements necessary for granting the required approvals under the Code have been fully satisfied, and the CPC Application should be approved without conditions.

VII. THE APPLICANT AND RELATED ENTITIES

A. Applicant

8. Transource PA is a limited liability company, organized and existing under the laws of Delaware. Transource PA is a wholly owned subsidiary of Transource Energy, LLC ("Transource Energy"), a partnership between two investor-owned utilities, American Electric

Power Company, Inc. ("AEP") and Evergy, Inc. ("Evergy"), formed to develop and invest in competitive electric transmission projects across the United States.

9. Transource PA was formed to construct, own, operate and maintain transmission facilities within the Commonwealth of Pennsylvania.

10. Transource PA is an existing PUC regulated transmission-only public utility in Peach Bottom Township, York County, Pennsylvania having been issued a CPC by the PUC on December 19, 2024 in the matter *Authorizing approval to Transource Pennsylvania, LLC to begin to offer, render, furnish, or supply electric transmission service to the public in Peach Bottom Township, York County, Pennsylvania,* PUC Docket No. A-2024-3049272.

11. The Commission previously granted Transource PA a provisional CPC and approved various affiliated interest agreements in an order entered on January 23, 2018 at Commission Docket Nos. A-2017-2587821 and G-2017-2587822 in connection with Transource PA's previous transmission line project in Franklin and York Counties, then known as the "Independence Energy Connection Project," also called the "IEC Project" or "Project 9A."[2] However, the CPC was rescinded when the Commission later denied Transource PA's separate application for the siting of the proposed IEC Project high voltage transmission line in an order entered May 24, 2021 at Docket Nos. A-2017-2640195 and A-2017-2640200.[3]

---

[2] The Independence Project had two components, the 9A East Project located in York County, Pennsylvania and the 9A West Project located in Franklin County, Pennsylvania. The 9A East Project and 9A West Project siting applications were docketed separately but were addressed in a single Order of the Commission.

[3]In an order dated December 6, 2023 at Docket No. 1:21-CV-01101, the United States Federal District Court for the Middle District of Pennsylvania ruled against the Commission on a federal question related to the Commission's scope of authority when reviewing PJM-approved applications to site transmission lines. That ruling was subsequently appealed by the Commission to the U.S. Court of Appeals for the Third Circuit ("Third Circuit") which, in a decision filed on September 5, 2025 at Docket No. 24-1045, reaffirmed the District Court order and held the PUC's action disregarding the findings of PJM Interconnection, L.L.C. ("PJM") with respect to the need for the IEC Project violated the Supremacy Clause of the U.S. Constitution. *Transource Pennsylvania, LLC v. DeFrank*, 156 F.4th 351 (Third Cir. 2025)("*Transource*"). The PUC has determined not to further challenge the Third Circuit's decision. Requests for intervention by the Pennsylvania Office of Consumer Advocate, the intervention and appearance as counsel by the Attorney General of the Commonwealth of Pennsylvania, and a request for rehearing *en banc* were filed with the

12. Upon receipt of all necessary approvals requested in this CPC Application and the Siting Application, Transource PA will site, construct, own, operate and maintain the 9A West Project in accordance with applicable law.

B. **Related Entities**

13. Transource Energy is a limited liability company organized and existing under the laws of Delaware. Transource Energy is headquartered in Columbus, Ohio.

14. Transource Energy is the direct parent of, and wholly owns, Transource PA.

15. Transource Energy participates in three RTOs, including PJM, the Midwest Independent System Operator, and the Southwest Power Pool. Transource Energy is focused on the development and investment in competitive electric transmission projects across the United States.

16. AEP is a corporation organized and existing under the laws of New York.

17. Headquartered in Columbus, Ohio, AEP is an energy and utility holding company that, through its subsidiaries: (i) serves more than 5.6 million customers in eleven states; (ii) owns and operates more than 40,000 transmission miles, and approximately 252,000 distribution miles; and (iii) has nearly 30,000 MW of generating capacity.

18. Evergy, headquartered in Kansas City, Missouri, was formed from the merger of Great Plains Energy Incorporated and Westar Energy, Inc. in 2018. Evergy's regulated utility units operate as Evergy Metro, Inc. (f/k/a Kansas City Power & Light Company ("KCP&L"),

---

Third Circuit. By Order dated November 6, 2025, the Pennsylvania Attorney General's Motion to withdraw as counsel and intervene in the appeal for purposes of reargument before the Third Circuit, *en banc*, was denied by a three-judge panel of the Third Circuit. The Pennsylvania Attorney General's requests to continue to challenge the Third Circuit's decision, commence representation of the Pennsylvania Office of the Consumer Advocate and be granted reargument before the Third Circuit, *en banc*, were denied by the Third Circuit. The Attorney General is currently seeking a grant of *certiorari* on these issues before the U.S. Supreme Court. This CPC Application seeks approval for a new CPC for Transource PA solely in connection with its proposed service in portions of Franklin County, Pennsylvania associated with the transmission line and substation project described further below as the "9A West Project."

Evergy Missouri West, Inc. (f/k/a KCP&L Greater Missouri Operations, Inc.) and Evergy Kansas Central, Inc. (f/k/a Westar Energy, Inc.). The Evergy operating companies have served customers in Kansas and Missouri for more than 100 years. Evergy's vertically integrated, regulated electric utilities serve approximately 1.7 million customers in Kansas and Missouri with 10,200 circuit miles of transmission lines and about 60,400 circuit miles of distribution lines.

19. Attached as Appendix 1 is an organizational chart showing Transource Energy and its primary current subsidiaries.

VIII. PROJECT 9A WEST

A. Project Background and Description

20. The 9A West Project involves the siting and construction of the new Rice-Ringgold 230 kV Transmission Line that will extend approximately 28.8 miles to connect the existing Ringgold Substation located near Smithsburg, Washington County, Maryland and the new Rice Substation to be located in Franklin County, Pennsylvania. Approximately 24.4 miles of the 9A West Project will be located in Pennsylvania and approximately 4.4 miles will be located in Maryland.

21. The Pennsylvania portion of the 9AWest Project will extend approximately 24.4 miles from the new Rice Substation to the Pennsylvania-Maryland border, and the Maryland portion of the 9A West Project will extend approximately 4.4 miles from the Pennsylvania-Maryland border to the existing Ringgold Substation. Transource PA will construct, own, operate, and maintain the Pennsylvania portion of the Rice-Ringgold 230 kV Transmission Line, and Transource MD will construct, own, operate, and maintain the Maryland portion of the line.
A map of the proposed 9A West Project is provided in Appendix 2 to this CPC Application.

22. The Rice-Ringgold 230 kV Transmission Line associated with the 9A West Project will be a 230 kV double-circuit transmission line. The 230 kV double-circuit design will utilize twelve power conductors, with two conductors used for each of the six phase positions, and two overhead ground wires.

B. **The Need for and the Public Benefits of the 9A West Project**

23. As described further below, the 9A West Project was borne out of PJM's planning process known as the Regional Transmission Expansion Plan ("RTEP") and Market Efficiency Analysis, which previously selected and identified the original transmission project known as "Project 9A."

24. RTOs, or regional transmission organizations, supervise interstate transmission and planning of electricity. The Federal Energy Regulatory Commission ("FERC") encouraged the formation of RTOs by requiring utilities to report their progress towards developing and participating in RTOs to FERC.[4] The purpose of such RTOs is for transmission facilities owned by utilities to be placed under the control of an appropriate RTO.[5]

25. FERC regulations require that each RTO have "operational authority for all transmission facilities under its control"[6] and "exclusive authority for maintaining the short-term reliability of the grid that it operates."[7]

26. PJM is a FERC-approved RTO charged with ensuring non-discriminatory access and the reliable and efficient operation of the electric transmission system under its functional

[4]*See* Order No. 2000, Regional Transmission Organizations, 65 Fed. Reg. 810, 811 (Jan. 6, 2000) (codified at 18 C.F.R. pt. 35).
[5]*Id*. at 811.
[6]18 C.F.R. § § 35.34(j)(3).
[7]Id. § 35.34(j)(4).

control and coordinating the transmission of electricity in all or parts of thirteen states, including Pennsylvania, and the District of Columbia.

27. In order to ensure reliable transmission service, PJM prepares an annual RTEP.[8] The RTEP is an annual planning process that encompasses a comprehensive series of detailed analyses to ensure electric power continues to flow reliably to customers under stringent reliability planning criteria.[9]

28. In addition to the reliability analysis, PJM's RTEP includes a Market Efficiency Analysis to identify congestion on electric transmission facilities that have economic or wholesale market effects, as well as potential improvements to electric transmission economic efficiencies. The electric transmission needs identified in this analysis stem from the fact that the PJM transmission grid provides the means for generators to participate in a competitive wholesale market to supply electricity, both capacity and energy, to customers in PJM's geographic footprint no matter where in this area the electrical load is located.

29. The electric transmission infrastructure needs identified by the PJM Market Efficiency Analysis are addressed by market efficiency transmission projects, which are aimed specifically at improving electric transmission economic efficiencies and alleviating electric transmission constraints that have an economic impact on PJM's wholesale energy or capacity markets.

[8] PJM's RTEP process is currently set forth in Schedule 6 of PJM's Amended and Restated Operating Agreement ("Schedule 6"). Schedule 6 governs the process by which PJM's members rely on PJM to prepare an annual regional plan for the enhancement and expansion of the transmission facilities to ensure long-term, reliable electric service consistent with established reliability criteria. In addition, Schedule 6 addresses the procedures used to develop the RTEP, the review and approval process for the RTEP, the obligation of transmission owners to build transmission upgrades included in the RTEP, and the process by which interregional transmission upgrades will be developed.

[9] PJM Manual 14B outlines the RTEP process and reliability criteria used for this process. PJM Manual 14B is available at: http://www.pim.com/~/media/docunients/manuals/ml4b.ashx,

30. When PJM's Market Efficiency Analysis identifies a need to relieve congestion on electric transmission facilities, PJM opens a Long-Term Proposal Window to solicit the submittal of potential solutions (*i.e.,* market efficiency projects) to address those needs. PJM's solicitation of market efficiency project submittals through its Long-Term Proposal Window is a competitive process consistent with FERC Order No. 1000.[10] Potential solutions are evaluated using two criteria: first, the project must address the congestion identified in the Market Efficiency Analysis; and, second, the project benefits must exceed the costs by at least 25 percent.[11] In addition, the project must meet PJM's congestion criteria and not create additional unacceptable congestion elsewhere on the system.

31. Market efficiency projects that are selected through PJM's Long Term Proposal Window are presented to stakeholders and recommended to the PJM Board of Managers ("PJM Board") for approval. If approved, such market efficiency projects are included in the RTEP as Baseline Projects.

32. Pursuant to Schedule 6 of PJM's Amended and Restated Operating Agreement, after the PJM Board approves a proposed market efficiency project, the successful project proponent is obligated to complete the project once PJM and the successful entity execute a Designated Entity Agreement, which specifically designates the entity or entities having construction responsibility for the project.

33. After extensive evaluation and review with stakeholders, PJM selected Project 9A to address the needs identified in PJM's 2014/2015 RTEP Long Term Proposal Window because it provided the highest benefit-to-cost ratio, the most total congestion savings, and the most

[10] A summary of FERC Order No. 1000 is available at: http://www.ferc.gov/industries/electric/indus- act/trans-plan.asp.
[11] Project benefits are measured by comparing the benefits in the form of net load payments and/or production costs with and without the proposed project for a 15-year study period. The economic benefit/cost ratio threshold test is set forth in PJM Manual 14B, Attachment E, available at: http://www.pim.eom/~/media/documents/manuals/ml4b.ashx.

production cost savings.[12] As part of the 2014/2015 RTEP, PJM estimated that Project 9A (of which the 9A West Project is a part) could lower wholesale electricity costs in congested-constrained regions.

34. On August 2, 2016, the PJM Board approved Project 9A as Baseline Upgrade Numbers b2743 and b2752, which included the 9A West Project.

35. PJM has conducted periodic annual re-evaluations of Project 9A since the project was placed in suspension status in 2021. PJM's 2025 annual re-evaluation showed a 3.85 benefit-to-cost ("B/C") ratio for the 9AWest Project – far exceeding the minimum 1.25 B/C ratio.

36. While other RTEP projects have been constructed since 2021 and therefore have obviated the need for what had been the eastern portion of the original Project 9A, PJM's staff recommended to PJM's Boad of Managers in May 2025 that the 9A West Project be completed given its positive benefits and favorable B/C ratio.

37. On July 30, 2025, the PJM Board of Managers found that the 9A West Project is needed and supports the prompt construction of needed infrastructure in the region. Such a determination establishes need for a project.[13]

38. Although the primary benefits from the 9A West Project relate to market efficiency and the reduction of congestion costs, the new transmission facilities associated with the 9A West Project will also enhance the electrical strength and reliability of the transmission system in the near term by virtue of the new transmission facilities in the area that will be part of the interconnected transmission grid. The 9A West Project will provide additional and alternative

[12]The recommendation of PJM staff to approve Project 9A is available at: http://www.pjm.com/~/media/committees-groups/committees/teac/20160811/20160811-boardwhitepaper-august-2016.ashx.
[13] See *Transource*.

paths for electricity in the event of outages on other transmission facilities. The 9A West Project will also allow the interconnection of potential future reliability and generation projects in the area.

C. Other 9A West Project Reviews and Approvals

39. Transource Pa has identified the general governmental approvals and permits likely to be necessary to construct the 9A West Project, in addition to the authorizations requested in this CPC Application and the Siting Application. The specific approvals, permits, etc. related to the siting, construction and operation of the 9A West Project are described in detail in the Siting Application. Upon approval of this CPC Application and the Siting Application, Transource Pa will provide electric transmission service in Pennsylvania in accordance with the PJM RTEP Process and approvals/directives outlined above.

IX. LEGAL STANDARDS APPLICABLE TO THE GRANTING OF A CPC

A. Service to or for the Public

40. A "public utility is defined in Code Section 102 as follows: Any person or corporation now or hereafter owning or operating in this Commonwealth equipment or facilities for:

> (i) Transmitting, distributing or furnishing … electricity … for the production of light, heat, or power to or for the public for compensation.

66 Pa. C.S. §102.

41. The Pennsylvania Supreme Court has concluded that "the public or private character of the enterprise does not depend upon the numbers of persons by whom it is used, but upon whether or not it is open to the use and service of all members of the public who may require it."[14] The Commonwealth Court found a gas company provided service "to or for the public"

[14] *Drexelbrook Associates v. Pa. PUC,* 418 Pa. 430, 435, 212 A.2d 237, 239 (1965) (citations omitted).

when it placed no restrictions upon whom it served and provided service to the extent that capacity was available on its facilities.[15]

42. Further, the Commission has also held that FERC-regulated transmission companies are "public utilities" under Pennsylvania law if they: (1) own, maintain, or operate in the Commonwealth equipment or facilities used for the transmission of electricity, and (2) directly or indirectly serve Pennsylvania customers for compensation.[16]

43. The electric transmission service to be furnished by Transource PA will be to or for the public for compensation.

B. **Code Section 1101 Certificate of Public Convenience**

44. Code Section 1101 provides that "[u]pon the application of any proposed public utility and the approval of such application by the [C]ommission evidenced by its certificate of public convenience first had and obtained, it shall be lawful for any such proposed public utility to begin to offer, render, furnish, or supply service within this Commonwealth." 66 Pa.C.S § 1101. Thus, before an entity may lawfully begin to furnish electric transmission service within the Commonwealth, it must first submit an application with the Commission requesting a certificate of public convenience.

45. Code Section 1103 sets forth the procedure to obtain a CPC. Under Code Section 1103, a CPC will be issued if the Commission "shall find and determine that the granting of such

[15] *Dunmire Gas Company v. Pa. PUC*, 413 A.2d 473, 474 (Pa. Cmwlth. 1980); see also *Waltman v. Pa. PUC*, 596 A.2d 1221 (Pa. Cmwlth. 1991), aff'd, 533 Pa. 304, 621 A.2d 994 (Pa. 1993) (holding that the public nature of the services were not changed by the fact that the only entities that would desire them were those engaged in high volume business).

[16] See *Petition of American Transmission Systems, Incorporated for a Declaratory Order that it is not a Public Utility as Defined in 66 Pa.* C.S. *§ 102 and is not Required to Obtain a Certificate of Public Convenience under 66 Pa.* C.S. *§ 1102(A) to Own and Operate Equipment and Facilities in Pennsylvania Used Only to Furnish Interstate Electric Transmission Service Subject to the Jurisdiction of the Federal Energy Regulatory Commission,* Docket No. P-2013-2388149 (Pa. PUC Order entered Aug. 11, 2016) (*"Petition of ATSI").*

certificate is *necessary or proper* for the service, accommodation, convenience or safety of the public."[17] 66 Pa.C.S. § 1103. The Commission has interpreted this section to require the applicant to demonstrate a public need for the service and the applicant's fitness to provide the service.[18]

46. In addition to public need and the applicant's fitness, an applicant for a CPC must demonstrate that the proposed service will "affirmatively promote the service, accommodation, convenience, or safety of the public in some substantial way."[19]

47. As explained in Section IV.B above and VI.B below, the electric transmission service to be furnished by Transource PA is reasonably necessary for the accommodation or convenience of the public.

48. Demonstrating the applicant's "fitness" involves three factors: (i) the technical capacity to meet the need in a satisfactory fashion; (ii) the financial ability to provide reliable and responsible service to the public; and (iii) legal fitness -- the ability to operate safely and legally.[20]

---

[17] The Commonwealth Court has stated that "necessity and need are corollaries" and, for purposes of high voltage transmission lines, "necessity can be established by showing an improvement in the reliability of services or lower prices." Moreover, the "necessary or proper" standard is to be read in the disjunctive. *Transource Pennsylvania, LLC v. Pa. Pub. Util. Comm'n*, 278 A.3d. 942 (Pa. Cmwlth. 2022).

[18] See *Chester Water Authority v. Pa. PUC*, 581 Pa. 640, 868 A.2d 384 (2005); Application of Newtown Artesian Water Company, 2003 Pa. PUC LEXIS 40 (July 1, 2003); See also *Transource* at 378-380. While the Company describes the need for Project 9A West in this CPC Application and supporting testimony, it also notes that the U.S. Third Circuit Court of Appeals recently held that, "when an RTO has selected [a multi-state transmission line project] for inclusion in a regional transmission plan as part of its federal mandate, a state regulator cannot, consistent with the Supremacy Clause, reject the project based on a lack of 'need'." *Transource Pa., LLC v. DeFrank*, 156 F.4th 351, 379 (3rd Cir. 2025), affirming *Transource Pa., LLC v. DeFrank*, 705 F. Supp. 3d 266 (M.D. Pa. 2023) ("*Transource")*. Thus, while the Commission holds authority over siting and construction of a project, it may not deny a project based on FERC's determination of need. *Id*. at 378. While this case law did not interpret a determination of whether there is a public need for the service contemplated by a new utility for purposes of obtaining a CPC under Code Sections 1101 and 1103(a), Transource PA submits that PJM's determination that there is a need for transmission service over Project 9A WAest and that Transource PA should construct, own, and operate the transmission facilities required to address this need demonstrates that there is a need for the electric transmission service contemplated by this CPC Application. Thus, Transource PA is submitting information regarding the benefits of and need for Project 9A West without prejudice to the decision in *Transource* and with a full reservation of rights both before the Commission and in the appellate courts.

[19] *City of York v. Pa. PUC,* 449 Pa. 136, 151, 295 A.2d 825, 828 (1972).

[20] See *Warminster Twp. Mun. Auth. v. Pa. P.U.C.,* 138 A.2d 240 (Pa. Super. 1958).

49. Under Code Chapter 11, Transource PA must demonstrate that it is legally, technically and financially fit.[21] While, as noted above, Transource PA holds a CPC as a public utility to serve in Peach Bottom Township, York County, Pennsylvania and may be entitled to a "presumption" of fitness under Pennsylvania law,[22] this CPC Application independently supports Transource PA's "fitness" to serve as a transmission-only utility in portions of Franklin County, Pennsylvania in connection with the 9A West Project.

50. As explained in Section VIII.C. below, Transource PA is technically, financially, and legally fit to provide electric transmission service in Franklin County, Pennsylvania. Further, such service will be to or for the public for compensation, and the service it will provide is necessary or proper for the service, accommodation, convenience or safety of the public.

X. TRANSOURCE PA SATISFIES ALL LEGAL REQUIREMENTS FOR THE GRANT OF A CPC

A. Transource PA Will Provide Service to or for the Public

51. As explained above, upon receipt of all necessary approvals and the completion of the 9A West Project, Transource PA will own, operate and maintain electric transmission facilities that will transmit high voltage electricity to various Pennsylvania electric transmission substations in support of the PJM RTEP process and directive described above.

52. The 9A West Project will be part of the interconnected wholesale electric grid that provides electric service to customers throughout the PJM 13-state footprint. The 9A West Project will be located in Pennsylvania and will be interconnected with existing and newly

[21] *Seaboard Tank Lines v. Pa. Pub. Util. Comm'n*, 502 A.2d 762, 764 (Pa. Cmwlth. 1985); *Warminster Township Mun. Auth. v. Pa. Pub. Util. Comm'n*, 138 A.2d 240, 243 (Pa. Super. 1958).
[22] See, *South Hills Movers, Inc. v. Pa. Pub. Util. Comm'n*, 601 A.2d 1308, 1310 (Pa. Cmwlth. 1992).

upgraded or constructed electric transmission facilities in Pennsylvania that will benefit customers in the region.

53. The Pennsylvania General Assembly has specifically directed the Commission to work with the Federal Government, interstate power pools such as PJM and other states in the region to ensure adequate, safe and reliable electric service to the citizens and businesses of the Commonwealth:

> The commission, Pennsylvania electric utilities and all electricity suppliers shall work with the Federal Government, other states in the region, the North American Electric Reliability Council and its regional coordinating councils or their successors, interstate power pools, and with the independent system operator or its functional equivalent to ensure the continued provision of adequate, safe and reliable electric service to the citizens and businesses of this Commonwealth.

66 Pa.C.S. § 2805(a).

54. As a PJM Transmission Owner, Transource PA will be required by federal law to provide open access to its facilities.[23] Thus, Transource PA will hold itself out and may be required to directly serve interconnection transmission customers, electric generators, independent power producers, and suppliers through the facilities and equipment to be located within Pennsylvania.

[23]FERC Order Nos. 888 and 889 require all public utilities owning and/or controlling transmission facilities to offer non-discriminatory open access transmission service. *See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs. P 31,036, 61 Fed. Reg. 21,540 (1996), clarified, 76 F.E.R.C. 61,009 and 76 F.E.R.C. 61,347 (1996), *on reh'g,* Order No. 888-A, FERC Stats. and Regs. P 31,048, 62 Fed. Reg. 12,274, *clarified,* 79 F.E.R.C. 61,182 (1997), *on reh'g,* Order No. 888-B, 81 F.E.R.C. 61,248, 62 Fed. Reg. 64,688 (1997), *on reh'g,* Order No. 888-C, 82F.E.R.C. 61,046 (1998); *Open Access Same-Time Information System and Standards of Conduct,* Order No. 889, FERC Stats. & Regs. P 31,035, 61 Fed. Reg. 21,737 (1996), *on reh'g,* Order No. 889-A, FERC Stats. & Regs. P 31,049, 62 Fed. Reg. 12,484 (1997), *on reh'g,* Order No. 889-B, 81 F.E.R.C. 61,253 (1997).

55. Although Transource PA will be compensated through FERC-regulated interstate rates for the electric transmission services it will provide,[24] the Commission will have jurisdiction over the siting, reliability, and safety of the overhead high voltage electric transmission line associated with the 9A West Project, as well as any future affiliated interest agreements.[25]

56. Under these facts, Transource PA submits that it will provide electric transmission service to or for the public for compensation.

B. The Proposed Electric Transmission Service to be Furnished by Transource PA is Reasonably Necessary for the Accommodation or Convenience of the Public.

57. As described above, the 9A West Project (i) was borne out of PJM's RTEP process (which has been directed and approved by FERC), (ii) has been authorized and approved by the PJM Board to address specific reliability and/or congestion needs in the transmission system, and (iii) is required to be completed in accordance with PJM's Operating Agreement.

58. As stated above, the 9A West Project will also enhance the area's electric transmission grid, allow for additional and alternative paths for electricity and facilitate the

[24]FERC Orders No. 888 and 889 require all public utilities owning and/or controlling transmission facilities to offer non-discriminatory open access transmission service. See *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. P 31,036, 61 Fed. Reg. 21,540 (1996), clarified, 76 F.E.R.C. 61,009 and 76 F.E.R.C. 61,347 (1996), on reh'g, Order No. 888-A, FERC Stats. and Regs. P 31,048, 62 Fed. Reg. 12,274, clarified, 79 F.E.R.C. 61,182 (1997), on reh'g, Order No. 888-B, 81 F.E.R.C. 61,248, 62 Fed. Reg. 64,688 (1997), on reh'g, Order No. 888-C, 82 F.E.R.C. 61,046 (1998); Open Access Same-Time Information System and Standards of Conduct, Order No. 889, FERC Stats. & Regs. P 31,035, 61 Fed. Reg. 21,737 (1996), on reh'g, Order No. 889-A, FERC Stats. & Regs. P 31,049, 62 Fed. Reg. 12,484 (1997), on reh'g, Order No. 889-B, 81 F.E.R.C. 61,253 (1997).

[25]See *Piedmont Environmental Council v. FERC*, 558 F.3d 304, 310 (4th Cir. 2009) (the siting of electric transmission lines is reserved for the states); 16 U.S.C. § 824(o)(i)(3) ("[n]othing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard"); *Application of TrAILCo For Approval For A Certificate Of Public Convenience To Offer, Render, Furnish Or Supply Transmission Service In The Commonwealth Of Pennsylvania*, Docket Nos. A-110172, et al., 2008 Pa. PUC LEXIS 1034 (Order entered Dec. 12, 2008) (states can exercise their authority to review certain affiliated interest agreements relating to transmission service and facilities without intruding on FERC's rate jurisdiction).

interconnection of potential future reliability and generation projects in the area as part of the area's transmission grid interconnected network.

59. There is no doubt that the 9A West Project is reasonably necessary for the service or accommodation of the public.[26] The 9A West Project is part of a recommended RTEP that has been submitted to, and approved by, the PJM Board. Therefore, it has been determined to be needed and ordered to be constructed by the PJM Board.

C. Transource PA is Technically, Financially and Legally Fit to Provide Electric Transmission Service in Pennsylvania

1. Technical Fitness

60. Transource PA and its parent Transource Energy have the required managerial and technical experience to own and operate the 9A West Project and all related equipment and facilities to render electric transmission service in Pennsylvania and beyond.

61. As explained above, Transource PA is the direct subsidiary of Transource Energy, which is indirectly owned by a partnership between AEP and Evergy. Transource Energy and Transource PA do currently and will continue to be able to draw on the significant resources and experience of AEP's and Evergy's rigorous and proven project management practices.

62. AEP and Evergy currently employ approximately 645 total employees in transmission project management and construction management functions. Combined, AEP and Evergy annually manage more than $5.95 billion in projects and have extensive experience in transmission projects of a magnitude comparable to the 9A West Project.

[26]For example, Pennsylvania for decades has held that regional integration is a direct intrastate benefit that can support the necessity requirement for exercising eminent domain authority. See, *Stone v. Pennsylvania Utility Commission*, 162 A.2d 18 (Pa. Super 1960).

63. Transource Energy operates its transmission assets with the highest standards of reliability, safety, and North American Electric Reliability Corporation ("NERC")[27] compliance. Both AEP and Evergy operate multiple, fully functional control centers and employ more than 1,000 personnel in field operations to maintain, operate and restore transmission systems. Further, AEP and Evergy have developed best-in-industry skills through over a 100+ year history of siting, designing, constructing, and operating transmission grids consisting of approximately 50,000 miles of transmission lines and related substations.

64. In addition, as part of its current business practice, AEP has established partnerships with third-party engineering consultants who are trained in the appropriate application of AEP specifications and standards. Additionally, AEP has extensive experience in providing oversight to external consultants and third-party contractors, with industry-leading capabilities to effectively oversee all types of transmission and substation siting, permitting, design and construction completed by outside firms.[28]

65. By combining the unique capabilities of AEP and Evergy, Transource Energy and Transource PA have currently and will continue to have the necessary experience and expertise to successfully construct, own, operate, and maintain the 9A West Project within Pennsylvania.

2. Legal Fitness

66. Transource PA is fully authorized to conduct business in the Commonwealth of Pennsylvania and is not the subject of any civil or criminal investigations or enforcement

[27] On February 3, 2006, FERC certified NERC as the organization required to establish and enforce reliability standards for the bulk electric system.
[28] *Transource Pennsylvania*, LLC, Docket No. ER23-1407-001, 184 FERC ¶61,091 (issued August 11, 2023), p. 12. (Omitting internal footnotes).

proceedings. Upon receipt of Commission approval, Transource PA will continue to be legally fit to own and operate electric transmission facilities within the Commonwealth of Pennsylvania.

67. Transource PA is a direct subsidiary of Transource Energy, which is indirectly owned by a partnership between AEP and Evergy. Transource Energy and its affiliates are in compliance in all material respects with federal and state laws in the jurisdictions in which they operate.

3. Financial Fitness

68. Transource Energy and Transource PA have the financial fitness to construct, own, maintain, and operate the 9A West Project and all related electric transmission facilities to be constructed, owned, operated and maintained in portions of Franklin County, Pennsylvania.

69. Attached to this Application as Appendix 3 is Transource PA's FERC Form No. 1. Through its own financial resources, along with financial support from its parent/affiliate, Transource Energy, Transource PA has the financial fitness and resources necessary to construct, own and operate the 9A West Project. Further, the borrowing capacity of Transource Energy through an existing credit agreement ("Transource Energy Credit Agreement") can be sized as needed, and the existing credit facility is more than sufficient to accommodate the anticipated debt financing needs for the construction of the 9A West Project. The Transource Energy Credit Agreement, called the "Third Amended and Restated Credit Agreement" dated as of February 20, 2025, is attached as Confidential Appendix 4. The current borrowing capacity for the Transource Energy Credit Agreement is $200 million. The terms of that agreement allow for an increase in total borrowing capacity up to $300 million. This opens an additional $100 million of available credit, which creates additional assurance that Transource

Energy can quickly and adequately finance additional projects under the current agreement. Presently, Transource Energy has immediate access to $111 million from the existing $200 million available, along with the $100 million accordion (i.e., expansion). Additionally, Transource Energy can leverage its diversified banking relationships and manage credit facility utilization through accessing private placement capital markets and opportunistically securing long-term debt at favorable terms. This option will allow Transource Energy to ensure that the 9A West Project capital needs are met. As Transource PA needs funds to support the construction, ownership and/or operation of the 9A West Project, it will effectively incur indebtedness to Transource Energy.

70. Transource PA's financial fitness is demonstrated by the credit rating of its direct parent, Transource Energy, whose Moody's credit rating is A2. A copy of Transource Energy's most recent Moody's credit opinion is attached as Confidential Appendix 5 .

71. The financing terms and lower debt costs available to Transource Energy as a result of its strong A2 Moody's credit rating will ultimately benefit Transource PA by reducing the cost of financing the 9A West Project. Moody's A2 credit rating reflects the financial strength and credit metrics of Transource Energy, and in this context evidences Transource PA's access to debt financing and its financial fitness to construct, own, operate, and maintain the Pennsylvania transmission facilities described in this CPC Application.

72. Transource PA's financial fitness is further evidenced by the most recent financial statements of its ultimate parent companies, AEP and Evergy. Transource PA's ultimate parents have combined available liquidity of approximately $4.3 billion, which far exceeds any equity contribution or inter-company debt amount that might be needed to support Transource PA's present transmission projects. AEP's and Evergy's most recent 10-Ks, are provided in Appendix 6 and Appendix 7, respectively.

73. In addition to the strong balance sheets, both ultimate parents of Transource PA have investment grade credit ratings. The most recent Moody's credit ratings reports for AEP and Evergy, as well as the past five years of credit ratings history, are attached as Confidential Appendix 8. Through Transource Energy, Transource PA will have ready access to debt and equity capital as needed to fulfill its funding requirements to construct, own, operate, and maintain the 9A West Project and any related future electric transmission facilities. AEP and Evergy have a track record of working with a significant number of banks worldwide in raising tens of billions of dollars for energy infrastructure, including over $5 billion of long-term debt financing specifically for transmission-only businesses. Transource Energy, as an affiliate of AEP and Evergy, benefits from these relationships and experience in the capital markets.

XI. RATES AND COST RECOVERY

74. The costs required to construct, place in service and operate and maintain the Transource PA transmission grid upgrades, such as the 9A West Project, are recovered exclusively through FERC-regulated transmission wholesale rates. The costs associated with each of Transource PA's transmission grid upgrades are allocated under FERC-regulated cost allocation principles, which may vary from project to project, and are subject to modification by FERC under federal law. Transource PA will not recover any costs or receive any revenue through retail rates because it will not have retail customers in Pennsylvania.[29]

75. Transource PA will have no retail customers and therefore no rates set by the Commission.

[29] Transource PA is currently recovering costs and receiving revenue through its FERC-regulated transmission formula rates in connection with all of its projects included in the PJM RTEP, and consistent with FERC's incentive orders for each project. See, e.g., *Transource Pennsylvania, LLC*, Docket No. ER23-1407-001, 184 FERC ¶61,091 (issued August 11, 2023).

XII. OTHER REQUIRED REGULATORY APPROVALS AND ADDITIONAL SUPPORTING DATA

76. The 9A West Project involves a multi-state interstate transmission line that traverses Pennsylvania and Maryland, and will require regulatory approvals from each of these jurisdictions.

77. In Pennsylvania, the 9A West Project will require Commission approval of this CPC Application and the Siting Application that will be filed contemporaneously herewith.

78. Transource PA will also seek Commission approval of the Zoning Petition.

79. Additional supporting information is provided in the testimony and exhibits submitted with the Siting Application for the 9A West Project, which is being filed contemporaneously herewith.

XIII. REQUEST FOR CONSOLIDATION OF RELATED PROCEEDINGS AND EXPEDITED CONSIDERATION

80. As noted above, this CPC Application and the Siting Application are being filed simultaneously with the Commission. The transmission line that is the subject of the Siting Application is directly related to the public utility service to be provided by Transource PA as a Pennsylvania electric transmission-only public utility in Franklin County, Pennsylvania if this CPC Application is approved.

81. Because the facts, evidence, and approvals required for the above-referenced proceedings are interrelated with the issues and evidence to be presented and addressed for this CPC Application, Transource PA requests, pursuant to 52 Pa. Code § 57.75(i)(1), that these Applications and the Zoning Petition be consolidated and considered simultaneously for purposes of hearings and decision

82. In consideration of the fact that: (i) Transource PA is the current holder of a CPC to provide transmission service in Pennsylvania, (ii) Transource PA has held provisional authority

to render transmission service in the same portions of Franklin County as is requested herein, and (iii) public utility status will assist Transource PA in developing the 9A West Project as directed by PJM, Transource PA respectfully requests that the PUC approve this Application as expeditiously as possible.[30]

XIV. NOTICE

83. Transource PA is serving copies of this filing on the Commission's Bureau of Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate. A service list is attached to the cover letter that accompanies this CPC Application. Transource PA respectfully requests that the Commission publish notice of this filing in the Pennsylvania Bulletin with a reasonable deadline for intervention in this proceeding. Transource PA will provide any additional documents that may be required by the Commission.

XV. CONCLUSION AND SUMMARY OF REQUESTED COMMISSION APPROVAL

WHEREFORE, for all the foregoing reasons, Transource Pennsylvania, LLC respectfully requests that the Pennsylvania Public Utility Commission grant and issue all necessary and customary approvals and orders, and issue it the necessary certificate(s) of public convenience under the Public Utility Code to:

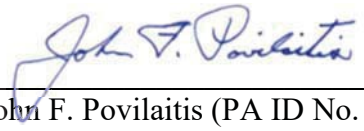
1. Begin to furnish and supply electric transmission service to or for the public within portions of Franklin County, Pennsylvania specified herein as a transmission-only public utility;

2. Carry out the transactions contemplated by this CPC Application; and

[30] Expedited review by the PUC will not limit the scope of the review, foreclose parties from raising relevant issues or limit or modify Transource PA's burden of proof. *Re Philadelphia Gas Works*, Docket No. P-00001829, 2000 WL 1511059 (Entered August 17, 2000).

3. Consolidate this CPC Application with the Siting Application and Zoning Petition contemporaneously filed herewith.

Respectfully submitted,



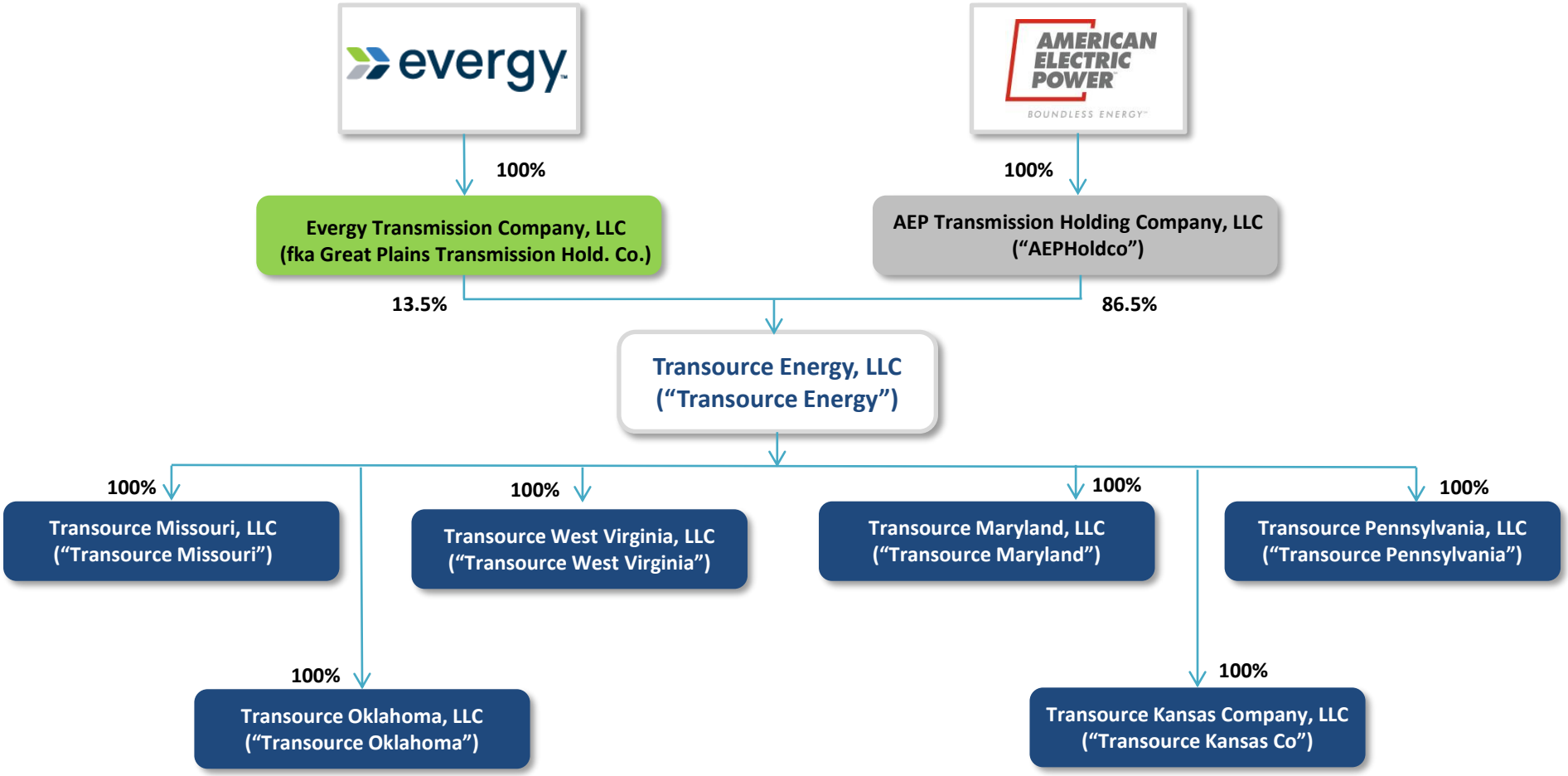
John F. Povilaitis (PA ID No. 28944)
Alan M. Seltzer (PA ID No. 27890)
409 N. Second Street, Suite 500
Harrisburg, PA 17101
Phone: (717) 237-4800
Fax: (717) 233-0852
Email: john.povilaitis@bipc.com
E-mail: alan.seltzer@bipc.com

Jessica A. Cano (FL ID. No. 37372)
American Electric Power Service Corporation
1 Riverside Plaza, 29th Floor
Columbus, OH 43215
Phone: 614-716-2921
Fax: 614-716-1613
E-mail: jacano@aep.com

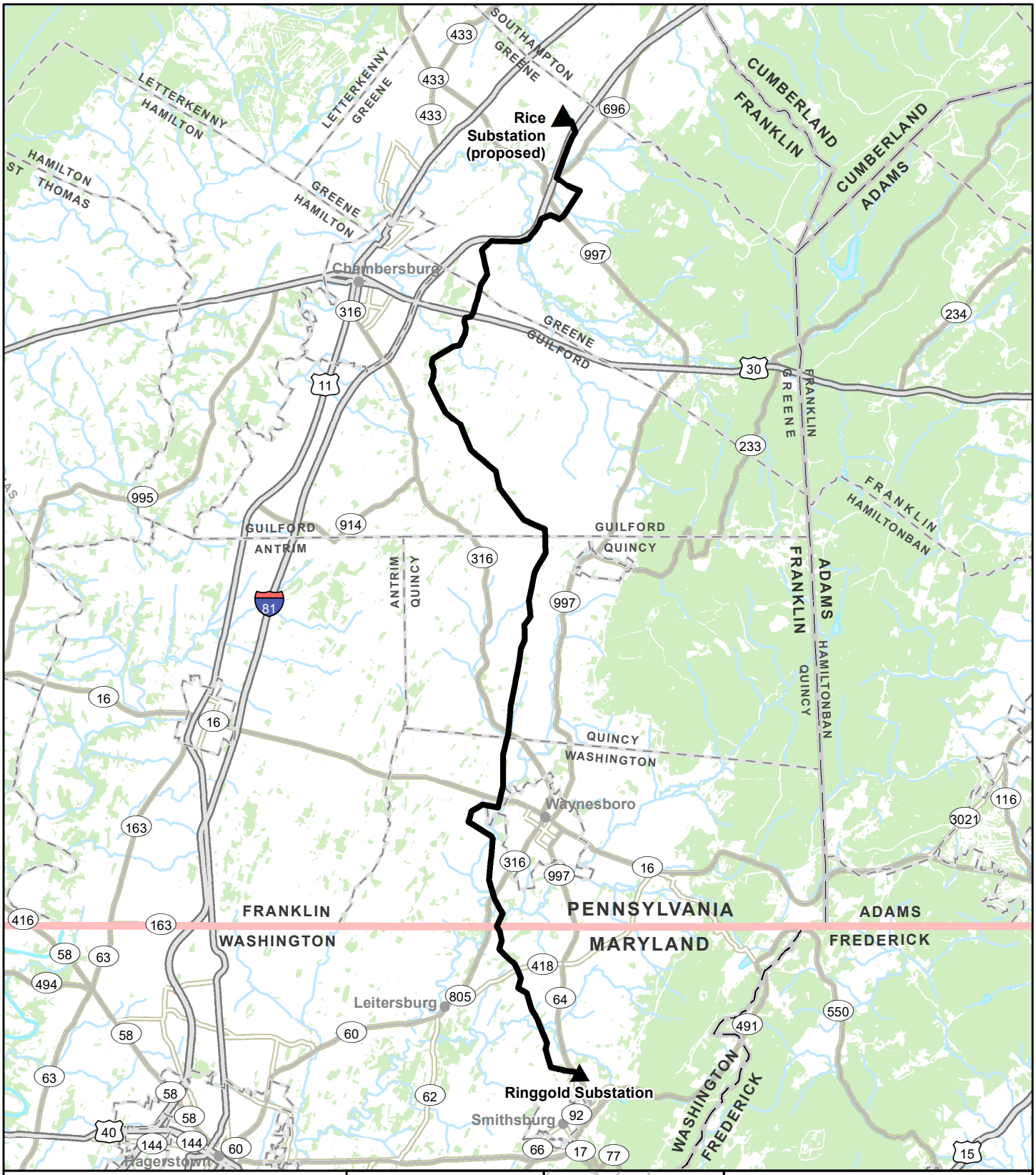
Attorneys for Transource Pennsylvania, LLC

Dated: May 21, 2026

APPENDIX 1


evergy
AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY
100%
100%
Evergy Transmission Company, LLC
(fka Great Plains Transmission Hold. Co.)
AEP Transmission Holding Company, LLC
("AEPHoldco")
13.5%
86.5%
Transource Energy, LLC
("Transource Energy")
100%
Transource Missouri, LLC
("Transource Missouri")
100%
Transource West Virginia, LLC
("Transource West Virginia")
100%
Transource Maryland, LLC
("Transource Maryland")
100%
Transource Pennsylvania, LLC
("Transource Pennsylvania")
100%
Transource Oklahoma, LLC
("Transource Oklahoma")
100%
Transource Kansas Company, LLC
("Transource Kansas Co")

APPENDIX 2



Substation
Alternative Route C (Proposed Route)
Highway
Road
Stream
Forest Cover

Data Sources: Transource (2026), Rextag Electric Transmission (2021), NLCD Forest Cover (2024)

Coordinate System:
UTM Zone 18N
NAD 83

May 03, 2026

Figure 1
Proposed Route

Rice - Ringgold 230 kV
Transmission Line Project

TRANSOURCE

0 1 2 3 4
Miles

APPENDIX 3

THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company) Transource Pennsylvania, LLC	Year/Period of Report End of: 2025/ Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

1. one million megawatt hours of total annual sales,
2. 100 megawatt hours of annual sales for resale,
3. 500 megawatt hours of annual power exchanges delivered, or
4. 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

a. Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

b. The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

c. Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

d. For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a. Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b. Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e. The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

f. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

g. Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

IV. When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

a. FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b. FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII. For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

X. Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was

obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

3. 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

4. 'Person' means an individual or a corporation;

5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....

11. "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

a. 'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/ Period of Report
Transource Pennsylvania, LLC	End of: 2025/ Q4

03 Previous Name and Date of Change (If name changed during year)
/

04 Address of Principal Office at End of Period (Street, City, State, Zip Code)
1 Riverside Plaza, 26th Flr, Columbus, OH 43215-2373

05 Name of Contact Person	06 Title of Contact Person
Jason M. Johnson	Accountant

07 Address of Contact Person (Street, City, State, Zip Code)
1 Riverside Plaza, 26th Flr, Columbus, OH 43215-2373

08 Telephone of Contact Person, Including Area Code	09 This Report is An Original / A Resubmission	10 Date of Report (Mo, Da, Yr)
(614) 716-1000	(1) ☑ An Original (2) ☐ A Resubmission	04/14/2026

Annual Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed (Mo, Da, Yr)
Michael D. Piatt	Michael D. Piatt	04/14/2026
02 Title		
VP Controller		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	**General Information**	101	
2	**Control Over Respondent**	102	
3	**Corporations Controlled by Respondent**	103	N/A
4	**Officers**	104	
5	**Directors**	105	
6	**Information on Formula Rates**	106	
7	**Important Changes During the Year**	108	
8	**Comparative Balance Sheet**	110	
9	**Statement of Income for the Year**	114	
10	**Statement of Retained Earnings for the Year**	118	
12	**Statement of Cash Flows**	120	
12	**Notes to Financial Statements**	122	
13	**Statement of Accum Other Comp Income, Comp Income, and Hedging Activities**	122a	
14	**Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep**	200	
15	**Nuclear Fuel Materials**	202	N/A
16	**Electric Plant in Service**	204	
17	**Electric Plant Leased to Others**	213	N/A
18	**Electric Plant Held for Future Use**	214	N/A
19	**Construction Work in Progress-Electric**	216	
20	**Accumulated Provision for Depreciation of Electric Utility Plant**	219	
21	**Investment of Subsidiary Companies**	224	N/A
22	**Materials and Supplies**	227	N/A
23	**Allowances and Environmental Credits**	228	N/A
24	**Extraordinary Property Losses**	230a	N/A
25	**Unrecovered Plant and Regulatory Study Costs**	230b	N/A
26	**Transmission Service and Generation Interconnection Study Costs**	231	N/A
27	**Other Regulatory Assets**	232	
28	**Miscellaneous Deferred Debits**	233	
29	**Accumulated Deferred Income Taxes**	234	
30	**Capital Stock**	250	N/A
31	**Other Paid-in Capital**	253	
32	**Capital Stock Expense**	254b	N/A
33	**Long-Term Debt**	256	
34	**Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax**	261	
35	**Taxes Accrued, Prepaid and Charged During the Year**	262	
36	**Accumulated Deferred Investment Tax Credits**	266	N/A
37	**Other Deferred Credits**	269	N/A
38	**Accumulated Deferred Income Taxes-Accelerated Amortization Property**	272	N/A
39	**Accumulated Deferred Income Taxes-Other Property**	274	
40	**Accumulated Deferred Income Taxes-Other**	276	
41	**Other Regulatory Liabilities**	278	
42	**Electric Operating Revenues**	300	
43	**Regional Transmission Service Revenues (Account 457.1)**	302	N/A
44	**Sales of Electricity by Rate Schedules**	304	N/A
45	**Sales for Resale**	310	N/A
46	**Electric Operation and Maintenance Expenses**	320	

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
47	**Purchased Power**	326	N/A
48	**Transmission of Electricity for Others**	328	
49	**Transmission of Electricity by ISO/RTOs**	331	N/A
50	**Transmission of Electricity by Others**	332	N/A
51	**Miscellaneous General Expenses-Electric**	335	
52	**Depreciation and Amortization of Electric Plant (Account 403, 404, 405)**	336	
53	**Regulatory Commission Expenses**	350	
54	**Research, Development and Demonstration Activities**	352	N/A
55	**Distribution of Salaries and Wages**	354	N/A
56	**Common Utility Plant and Expenses**	356	N/A
57	**Amounts included in ISO/RTO Settlement Statements**	397	N/A
58	**Purchase and Sale of Ancillary Services**	398	N/A
59	**Monthly Transmission System Peak Load**	400	N/A
60	**Monthly ISO/RTO Transmission System Peak Load**	400a	N/A
61	**Electric Energy Account**	401a	N/A
62	**Monthly Peaks and Output**	401b	N/A
63	**Steam Electric Generating Plant Statistics**	402	N/A
63.1	**Renewable Generating Plant Statistics**	404	
64	**Hydroelectric Generating Plant Statistics**	406	N/A
65	**Pumped Storage Generating Plant Statistics**	408	N/A
66	**Generating Plant Statistics Pages**	410	N/A
66.1	**Energy Storage Operations (Large Plants)**	414	
66.2	**Energy Storage Operations (Small Plants)**	419	
67	**Transmission Line Statistics Pages**	422	N/A
68	**Transmission Lines Added During Year**	424	N/A
69	**Substations**	426	N/A
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Michael D. Piatt, VP Controller

1 Riverside Plaza, 26th Flr, Columbus, OH 43215-2373

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Delaware - July 28, 2016

State of Incorporation:

Date of Incorporation:

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric - Ohio, Pennsylvania

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?
(1)
☐ Yes

(2)
☑ No

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

Transource Energy, LLC controls 100% of the Respondent as of December 31, 2025.

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Not Applicable			

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	President	David B.Stader		2025-12-18	
2	Senior Vice President	Stacey L. Burbure		2025-12-18	
3	Senior Vice President	Ryan L. Houk,		2025-07-17	
4	Controller	Michael D Piatt		2025-08-08	
5	Treasurer	Matthew D Fransen		2025-03-28	
6	Assistant Treasurer	Marc B.Hunter		2025-07-17	
7	Assistant Controller	Dana M.Koenig		2023-05-09	2025-03-22
8	President	Robert W. Bradish		2023-05-09	2025-03-28
9	Assistant Treasurer	Noah K.Hollis		2021-02-19	2025-03-28
10	President	Stacey L. Burbure,		2025-03-28	2025-04-02
11	Vice President	David E.Rupert,		2021-08-30	2025-06-02
12	Senior Vice President	Chad A.Heitmeyer		2022-05-20	2025-07-02
13	Assistant Treasurer	Carrie M.Luedtke.		2025-03-28	2025-07-17
14	Controller	Kate Dixon,		2023-05-09	2025-08-01
15	President	Stacey L.Burbure,		2025-04-10	2025-12-18

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Douglas A. Cannon (Manager)	Columbus, Ohio	false	false
2	Geoffrey T Ley, . (Manager)	Columbus, Ohio	false	false
3	Steven J. Vetsch (Manager)	Columbus, Ohio	false	false
4	Peter R. Wall (Manager)	Columbus, Ohio	false	false

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ Yes ☐ No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	PJM OATT Attachment H-29	ER17-419

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	☑ Yes ☐ No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20250630-5233	06/30/2025	ER17-419	AEP PJM OATT Annual Formula Rate True Up	PJM OATT Attachment H-30
2	20250930-5342	09/30/2025	ER17-419	AEP PJM OATT Annual Formula RateProjection	PJM OATT Attachment H-30

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

None

None

None

None

None

None

None

None

None

None

David B. Stader Elected as President on December 18th 2025
Stacey L.Burbure Elected as Senior Vice President on December 18th 2025
Ryan L.Houk Elected as Senior Vice President on July 17th 2025
Michael D.Piatt elected as Controller on August 08th 2025
Matthew D.Fransen elected as Treasurer on March 28th 2025
Marc B.Hunter elected as Assistant Treasurer on July 17th 2025
Carrie M. Luedtke elected as Assistant Treasurer on March 28th 2025
Stacey L.Burbure Elected as President on April 10th 2025
Stacey L.Burbure Elected as President on March 28th 2025
Stacey L.Burbure resigned as President on April 2nd 2025
Carrie M,Luedtke resigned as Assistant Treasurer on July 17th 2025
Stacey L.Burbure resigned as President on December 18th 2025

Proprietary capital ratio exceeds 30%

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	887,901	747,064
3	Construction Work in Progress (107)	200	146,414,876	116,971,053
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		147,302,777	117,718,117
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	405,189	382,643
6	Net Utility Plant (Enter Total of line 4 less 5)		146,897,588	117,335,474
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		146,897,588	117,335,474
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)			
19	(Less) Accum. Prov. for Depr. and Amort. (122)			
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances and Environmental Credits	228		
24	Other Investments (124)			
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)			
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)			
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		3,219,569	1,729,531
36	Special Deposits (132-134)		500,000	500,000
37	Working Fund (135)		750,000	
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		1,196,457	657,462
41	Other Accounts Receivable (143)		265,582	
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)			
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		1,047,580	146,136
45	Fuel Stock (151)	227		
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227		
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances and Environmental Credits (158.1, 158.2, 158.3, and 158.4)	228		
53	(Less) Noncurrent Portion of Allowances and Environmental Credits	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		19,256	21,150
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)			
62	Miscellaneous Current and Accrued Assets (174)			
63	Derivative Instrument Assets (175)			
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		6,998,444	3,054,279
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		164,609	195,797
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	312,646	3,593,316
73	Prelim. Survey and Investigation Charges (Electric) (183)			
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233		59,974
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)			
82	Accumulated Deferred Income Taxes (190)	234	145,980	156,230
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		623,235	4,005,317
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		154,519,267	124,395,070
		Page 110-111		

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250		
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)			
7	Other Paid-In Capital (208-211)	253	41,699,067	38,613,111
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118	17,542,823	21,030,528
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)		
16	Total Proprietary Capital (lines 2 through 15)		59,241,891	59,643,639
17	**LONG-TERM DEBT**			
18	Bonds (221)	256		
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256	63,200,000	60,200,000
21	Other Long-Term Debt (224)	256		
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)			
24	Total Long-Term Debt (lines 18 through 23)		63,200,000	60,200,000
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)			
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)			
29	Accumulated Provision for Pensions and Benefits (228.3)			
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		752,529	
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)			
35	Total Other Noncurrent Liabilities (lines 26 through 34)		752,529	
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		27,171,532	2,258,636
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		695,831	605,267
41	Customer Deposits (235)			
42	Taxes Accrued (236)	262	3,370,963	668,551
43	Interest Accrued (237)			
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)			
48	Miscellaneous Current and Accrued Liabilities (242)		1,529	6,187
49	Obligations Under Capital Leases-Current (243)			

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
50	Derivative Instrument Liabilities (244)			
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		31,239,855	3,538,641
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)			
57	Accumulated Deferred Investment Tax Credits (255)	266		
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269		
60	Other Regulatory Liabilities (254)	278		
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		31,538	42,411
64	Accum. Deferred Income Taxes-Other (283)		53,454	970,379
65	Total Deferred Credits (lines 56 through 64)		84,992	1,012,790
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		154,519,267	124,395,070
	Page 112-113			

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	11,751,147	11,306,683			11,751,147	11,306,683				
3	Operating Expenses											
4	Operation Expenses (401)	320	(225,118)	473,666			(225,118)	473,666				
5	Maintenance Expenses (402)	320	30,655	22,048			30,655	22,048				
6	Depreciation Expense (403)	336	170,825				170,825					
7	Depreciation Expense for Asset Retirement Costs (403.1)	336										
8	Amort. & Depl. of Utility Plant (404-405)	336		146,477				146,477				
9	Amort. of Utility Plant Acq. Adj. (406)	336										
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)											
13	(Less) Regulatory Credits (407.4)											
14	Taxes Other Than Income Taxes (408.1)	262	21,268				21,268					
15	Income Taxes - Federal (409.1)	262	2,437,767	746,834			2,437,767	746,834				
16	Income Taxes - Other (409.1)	262	797,660	(22,902)			797,660	(22,902)				
17	Provision for Deferred Income Taxes (410.1)	234, 272	379,435	1,786,346			379,435	1,786,346				

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	1,296,984	683,029			1,296,984	683,029				
19	Investment Tax Credit Adj. - Net (411.4)	266										
20	(Less) Gains from Disp. of Utility Plant (411.6)											
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)											
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)											
24.1	(Less) Gains from Disposition of Environmental Credits (411.11)											
24.2	Losses from Disposition of Environmental Credits (411.12)											
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24.2)		2,315,508	2,469,440			2,315,508	2,469,440				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		9,435,639	8,837,243			9,435,639	8,837,243				
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)											
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)											
33	Revenues From Nonutility Operations (417)											
34	(Less) Expenses of Nonutility Operations (417.1)											
35	Nonoperating Rental Income (418)											
36	Equity in Earnings of Subsidiary Companies (418.1)	119										
37	Interest and Dividend Income (419)		91,286	101,297								
38	Allowance for Other Funds Used During Construction (419.1)											
39	Miscellaneous Nonoperating Income (421)		156,556	168,556								
40	Gain on Disposition of Property (421.1)											
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		247,842	269,853								

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)											
44	Miscellaneous Amortization (425)											
45	Donations (426.1)											
46	Life Insurance (426.2)											
47	Penalties (426.3)		13	102								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		200,357									
49	Other Deductions (426.5)		5,530	101								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		205,900	203								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262										
53	Income Taxes-Federal (409.2)	262	33,311	51,838								
54	Income Taxes-Other (409.2)	262	14,717	22,902								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272										
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272										
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		48,028	74,740								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(6,086)	194,910								
61	Interest Charges											
62	Interest on Long-Term Debt (427)											
63	Amort. of Debt Disc. and Expense (428)		91,163	72,209								
64	Amortization of Loss on Reaquired Debt (428.1)											
65	(Less) Amort. of Premium on Debt-Credit (429)											
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)											
67	Interest on Debt to Assoc. Companies (430)		3,281,452	3,188,312								
68	Other Interest Expense (431)		44,642	123,771								

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)											
70	Net Interest Charges (Total of lines 62 thru 69)		3,417,257	3,384,292								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		6,012,295	5,647,861								
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		6,012,295	5,647,861								
Page 114-117												

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		21,030,528	15,382,666
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		6,012,295	5,647,861
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Distributions to Transource Energy		(9,500,000)	
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(9,500,000)	
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		17,542,823	21,030,528
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		17,542,823	21,030,528
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

STATEMENT OF CASH FLOWS

1. Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	6,012,295	5,647,861
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	170,825	146,477
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of		
8	Deferred Income Taxes (Net)	(917,548)	1,103,317
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	(1,706,020)	(110,270)
11	Net (Increase) Decrease in Inventory		
12	Net (Increase) Decrease in Allowances and Environmental Credits Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	4,823,294	1,357,931
14	Net (Increase) Decrease in Other Regulatory Assets	3,280,669	(1,223,348)
15	Net Increase (Decrease) in Other Regulatory Liabilities		
16	(Less) Allowance for Other Funds Used During Construction		
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):	[a]1,432,540	(661,720)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	13,096,055	6,260,248
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(6,856,017)	(26,066,457)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction		
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(6,856,017)	(26,066,457)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances and Environmental Credits Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
53	Other (provide details in footnote):		
53.1	Other (provide details in footnote):		
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(6,856,017)	(26,066,457)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	3,000,000	62,700,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
64.2	Long Term Issuance Costs		(198,769)
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Other (provide details in footnote):		
67.2	Capital Contributions from Parent	2,500,000	7,000,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	5,500,000	69,501,231
72	Payments for Retirement of:		
73	Long-term Debt (b)		(49,700,000)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Bond Issuance Costs		
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(9,500,000)	
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	(4,000,000)	19,801,231
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	2,240,038	(4,978)
88	Cash and Cash Equivalents at Beginning of Period	1,729,531	1,734,509
90	Cash and Cash Equivalents at End of Period	3,969,569	1,729,531

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

	Column (b) 2025 Cash Flow Incr / (Decr)	Column (c) 2024 Cash Flow Incr / (Decr)
Prepayments	$ 1,894	$ (1)
Utility Plant, Net	—	1
Other Deferred Debits, Net	59,974	69,237
Proprietary Capital, Net	585,957	1,008,554
Accumulated Provisions - Misc	752,529	—
Unamortized Debt Expense	31,189	2,972
Current and Accrued Liabilities, Net	997	(1,741,515)
Other Deferred Credits, Net	—	(968)
Total	**$ 1,432,540**	**$ (661,720)**

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However, where material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

INDEX OF NOTES TO FINANCIAL STATEMENTS

	Glossary of Terms for Notes
1.	Organization and Summary of Significant Accounting Policies
2.	New Accounting Standards
3.	Rate Matters
4.	Effects of Regulation
5.	Guarantees and Contingencies
6.	Fair Value Measurements
7.	Income Taxes
8.	Financing Activities
9.	Related Party Transactions
10.	Transmission Property
11.	Revenue from Contracts with Customers
12.	FERC Order No. 898

GLOSSARY OF TERMS FOR NOTES

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

Term	Meaning
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 subsidiaries and affiliates.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a subsidiary of AEP, an intermediate holding company that owns transmission operations joint ventures and AEPTCo.
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.
AFUDC	Allowance for Funds Used During Construction.
ASU	Accounting Standards Update.
ATRR	Annual transmission revenue requirement.
CWIP	Construction Work in Progress.
Evergy, Inc.	A public utility holding company incorporated in 2017 and headquartered in Kansas City, Missouri.
Evergy Metro, Inc.	A wholly-owned subsidiary of Evergy, Inc., provides certain support services to Transource Energy and subsidiaries.
Evergy Transmission Company, LLC	A wholly-owned subsidiary of Evergy, Inc., owns 13.5% of Transource Energy, LLC.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
GAAP	Generally Accepted Accounting Principles in the United States of America.
kV	Kilovolt.
OATT	Open Access Transmission Tariff.
PAPUC	Pennsylvania Public Utility Commission.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas. Transource Pennsylvania is a member of PJM. PJM is a FERC approved RTO.
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.
Transource Energy	Transource Energy, LLC, an AEP subsidiary formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Transource Maryland	A 100% wholly-owned subsidiary of Transource Energy.
Transource Pennsylvania	A 100% wholly-owned subsidiary of Transource Energy.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

Transource Pennsylvania was established to build and own transmission facilities in Pennsylvania. Transource Energy owns all of Transource Pennsylvania's outstanding equity. AEP Transmission Holdco and Evergy Transmission Company, LLC hold 86.5% and 13.5% membership interests in Transource Energy, respectively.

AEPSC and Evergy Metro, Inc. provide services to Transource Energy through service agreements. Transource Pennsylvania does not have employees.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

The FERC and the PAPUC regulate Transource Pennsylvania's rates and are permitted to review and audit Transource Pennsylvania's books and records. The FERC regulates the affiliated transactions of Transource Pennsylvania, including affiliated transactions involving AEPSC and Evergy Metro, Inc. billings at cost under the 2005 Public Utility Holding Company Act and the Federal Power Act.

The FERC has issued an order authorizing the inclusion of the Transource Pennsylvania formula rate and transmission revenue requirement in the OATT administered by PJM. The FERC order implemented an ATRR for Transource Pennsylvania. Under this revenue requirement, Transource Pennsylvania makes annual filings in order to recover prudently incurred costs (including amortization of the pre-commercial cost regulatory assets) and an allowed return from wholesale transmission customers of PJM. An annual rate filing is made for each calendar year using estimated costs, which is used to determine the billings to PJM ratepayers. The annual rate filing is compared to actual costs with any under- or over-recovery being trued-up with interest and recovered or refunded in future year rates. The FERC has approved the use of a formula rate methodology for recovery of all prudently incurred operation and maintenance expenses, a return on debt and equity on all capital expenditures in connection with Transource Pennsylvania's projects as well as an income tax allowance. As a result, Transource Pennsylvania recognizes revenue when the underlying performance obligations are satisfied.

Basis of Accounting

Transource Pennsylvania's accounting is subject to the requirements of the FERC and the PAPUC. The financial statements have been prepared in accordance with the Uniform System of Accounts prescribed by the FERC. The principal differences from GAAP include:

- The requirement to report deferred tax assets and liabilities separately rather than as a single amount.
- The exclusion of current maturities of long-term debt from current liabilities.
- The classification of accrued taxes as a single amount rather than as assets and liabilities.
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of certain nonoperating expenses as miscellaneous nonoperating expense instead of as operating expense.
- The separate classification of income tax expense for operating and nonoperating activities instead of as a single income tax expense.
- The inclusion of income taxes as a component of the financial statements rather than the exclusion of income taxes due to structure as a limited liability company.
- The classification of debt issuance costs as noncurrent assets instead of noncurrent liabilities.
- The classification of certain expenses in operating income rather than operating expenses.
- The classification of cloud computing implementation costs as Utility Plant rather than as a noncurrent asset.
- The classification of carrying charges for transmission over/under recovery in non-operating income rather than non-operating expenses.
- The classification of depreciation of cloud computing as depreciation and amortization rather than as operating expenses.
- The classification of global borrowing interest payable to affiliated companies as accounts payable rather than accrued interest.

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated entity, Transource Pennsylvania's 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. Under the Transource Pennsylvania's formula rate mechanism and in accordance with accounting guidance for "Regulated Operations," Transource Pennsylvania records regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred revenue reductions or refunds) 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 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, long-lived asset impairment, the effects of regulation including formula rate revenues, long-lived asset recovery and the effects of contingencies. 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 on the statements of cash flows include Cash, Working Fund and Temporary Cash Investments on the balance sheets with original maturities of three months or less.

Supplementary Information

For the Years Ended December 31,	2025	2024
	(in thousands)	
Cash Paid for Interest (Net of Capitalized Amounts)	$ 3,123	$ 2,973
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	23,157	280

Accounts Receivable

Accounts receivable primarily includes receivables from PJM based on the monthly allocation of the tariff rates that were authorized in the FERC order.

Transmission Property

Transmission property is stated at original cost. Additions, major replacements and betterments are added to the property accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as poles, transformers, 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 an affiliated company as a proxy of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs, when incurred, will be charged to accumulated depreciation. The costs of labor, materials and overhead incurred to operate and maintain the transmission property is included in operating expenses.

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, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense.

The fair value of an asset or investment is the amount at which that asset or investment 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 or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

CWIP and AFUDC

The FERC has issued an order approving Transource Pennsylvania's request to include CWIP in recoverable rate base, instead of accruing AFUDC during construction. If this incentive had not been granted, Transource Pennsylvania would have capitalized $9.8 million and $9.1 million of AFUDC in CWIP during 2025 and 2024, respectively. As of December 31, 2025 and 2024, Transource Pennsylvania's Utility Plant would have been $37 million and $27.2 million higher, respectively, as a result of AFUDC if it had been capitalized during construction.

Valuation of Nonderivative Financial Instruments

The book values of Cash, Special Deposits, Accounts Receivable from Associated Companies, Accounts Payable to Associated Companies, Customer Accounts Receivable and Accounts Payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

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.

Revenue Recognition

Regulatory Accounting

Transource Pennsylvania’s 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, Transource Pennsylvania records them as assets on its balance sheets. Transource Pennsylvania tests for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a FERC 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.

Transmission Revenue Accounting

Pursuant to an order approved by the FERC, Transource Pennsylvania is included in the OATT administered by PJM. The FERC order implemented an ATRR for Transource Pennsylvania. Under this requirement, AEPSC, on behalf of Transource Pennsylvania, makes annual filings in order to recover prudently incurred costs (including amortization of the formation cost regulatory asset) and an allowed return on plant in service and CWIP. An annual formula rate filing is made for each calendar year using estimated costs, which is used to determine the billings to PJM ratepayers. The estimated costs in the annual rate filing is compared to actual costs with any over- or under-recovery being trued-up with carrying charges and recovered or refunded 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 Transource Pennsylvania in the fourth quarter of each calendar year and a final annual true-up is recognized by Transource Pennsylvania in the second quarter of each calendar year following the filing of annual FERC.
Transource Pennsylvania recognizes revenue when the underlying performance obligations to design, develop, construct, operate and maintain the transmission plant are satisfied and as it incurs recoverable costs and earns the allowed return on plant in service and CWIP on a monthly basis. See Note 11 - Revenue from Contracts with Customers for additional information.

Income Taxes

Transource Pennsylvania is a tax partnership that is owned 86.5% by AEP Transmission Holdco and 13.5% by Evergy Transmission Company, LLC. As a result, Transource Pennsylvania is not liable for federal or state income taxes. The income tax effect of Transource Pennsylvania’s activities flows directly to AEP Transmission Holdco (a single-member limited liability company, taxable as a corporation) and Evergy Transmission Company, LLC (a single-member limited liability company). AEP Transmission Holdco and Evergy Transmission Company, LLC’s tax owner entity report their respective shares of Transource Pennsylvania’s earnings, gains, losses, deductions and tax credits on their respective federal and state income tax returns.

Transource Pennsylvania is allowed, however, to recover in rates, as a component of its cost of service, the amount of income taxes that are the responsibility of AEP Transmission Holdco and Evergy Transmission Company, LLC’s tax owner entity. Transource Pennsylvania is also required to adjust its rate base by the amount of deferred tax assets and liabilities it would have recorded if it were a taxable corporation.

Subsequent Events

Management reviewed subsequent events through April 14, 2026, the date that Transource Pennsylvania’s 2025 FERC Form 1 was available to be issued.

2. NEW ACCOUNTING STANDARDS

During the FASB’s standard-setting process and upon issuance of final standards, management reviews the new accounting literature to determine its relevance, if any, to Transource Pennsylvania’s business. The following standard will impact Transource Pennsylvania's financial statements.

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. RATE MATTERS

Transource Pennsylvania is involved in rate and regulatory proceedings at the FERC and PAPUC. Rate matters can have a material impact on net income, cash flows and possibly financial condition. Recent significant rate orders and pending rate filings are addressed in this note.

Formula Rate

Transource Pennsylvania submits an annual filing with PJM which establishes its projected transmission revenue requirement (PTRR). The new rates become effective at the beginning of the year and are subject to refund and true-up. The formula rates establish rates for one year and also include a true-up calculation for the prior year's billings, allowing for (over)/under-recovery of the PTRR. The following table summarizes Transource Pennsylvania's PTRR's with remaining (over)/under-recovery balances:

Year	PTRR	Total (Over)/Under-Recovery	Remaining (Over)/Under-Recovery	
			December 31, 2025 (a)	December 31, 2024
		(in thousands)		
2024	$ 10,192	$ 1,358	$ 1,300	$ 1,418
2025	12,677	(753) (b)	(753)	—
2026	19,506	— (b)	—	—

(a) As of December 31, 2025, the remaining (over)/under-recovery balance was recorded as $(753) thousand as Accumulated Provision for Refunds, $313 thousand as Other Regulatory Assets and $987 thousand as Accounts Receivable from Associated Companies.
(b) These amounts represent estimated (over)/under-recovered revenues, subject to refund and true up. The true-up of these revenues will be incorporated in a future PTRR that is filed in the third quarter of each calendar year. The 2025 true-up will be incorporated in the 2027 PTRR and the 2026 true-up will be incorporated in the 2028 PTRR.

Independence Energy Connection Project

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, through its Transource Maryland and Transource Pennsylvania subsidiaries. In June 2020, the Maryland Public Service Commission (MPSC) approved a Certificate of Public Convenience and Necessity to construct the portion of the IEC in Maryland for Transource Maryland. In May 2021, the PAPUC denied the IEC certificate for siting and construction of the portion in Pennsylvania for Transource Pennsylvania. Transource Pennsylvania 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. In December 2023, the United States District Court for the Middle District of Pennsylvania granted summary judgment in favor of Transource Pennsylvania, 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 Pennsylvania. The Pennsylvania Attorney General subsequently petitioned to intervene, which the United States Court of Appeals for the Third Circuit denied. The Pennsylvania Attorney General sought review of the United States Court of Appeals for the Third Circuit’s denial at the United States Supreme Court, which is pending.

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, the PJM Board of Managers suspended without cancellation of the IEC pending resolution of TPA’s state and federal challenges to the PAPUC’s denial to authorize siting and construction of TPA’s facilities in Pennsylvania. Accordingly, milestones in the applicable Designated Entity Agreement were modified so that they would be suspended during the pendency of the legal proceedings. Transource Pennsylvania was directed to limit expenditures on the IEC to those reasonably necessary to maintain the project during suspension. PJM re-affirmed that at the time there had been no change in PJM’s determination of need for the IEC to resolve congestion on the AP South Reactive Interface and related constraints.

In July 2025, PJM removed the IEC from suspended status and indicated the project, now Project 9A, going forward will be included in PJM’s models, which assume the project is constructed and placed in service with a modified scope of work to eliminate certain facilities while re-affirming the need for the remaining facilities to resolve congestion on the AP South Reactive Interface and related constraints.

As of December 31, 2025, Transource Pennsylvania’s share of the IEC capital expenditures was approximately $88.9 million located in Net Utility Plant on its balance sheets. The FERC has previously granted abandonment benefits for this project, allowing the full recovery of prudently incurred costs if the project is cancelled for reasons outside the control of Transource Maryland or Transource Pennsylvania. If any of the IEC costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Bramah Station

Bramah Substation was originally awarded to Transource Pennsylvania by PJM in December 2021 through the New Jersey offshore wind statement agreement approach. In December 2023, PJM re-awarded Bramah to Transource Pennsylvania with a revised scope to address regional reliability needs.

Transource Pennsylvania is advancing the development of Bramah Substation, a 500/230 kV substation near Delta, Pennsylvania. This project encompasses greenfield substation construction and cut-in work for the new and existing 500 kV and 230 kV transmission lines entering the substation. Project engineering, material procurement, and permit applications are proceeding as planned. Transource Pennsylvania’s Certificate of Public Convenience (CPC) application filed with the PAPUC in May 2024 was approved in December 2024. In January 2026, Transource Pennsylvania filed an additional CPC application to acquire several easements in York County, Pennsylvania.

Construction on the substation began in March 2026, and it is projected to be in service by the end of 2027.

4. EFFECTS OF REGULATION

Transource Pennsylvania did not have any regulatory liabilities as of December 31, 2025 and 2024. Regulatory assets are comprised of the following items:

	December 31, 2025	December 31, 2024	Remaining Recovery Period
Regulatory Assets:	(in thousands)		
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
FERC Formula Rates Under-Recovery	$ 313	$ 3,593	2 years
Total Regulatory Assets Approved for Recovery	313	3,593	
Total FERC Account 182.3 Regulatory Assets	$ 313	$ 3,593	

5. GUARANTEES AND CONTINGENCIES

Transource Pennsylvania is subject to certain claims and legal actions arising in its ordinary course of business. In addition, Transource Pennsylvania's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. Transource Pennsylvania 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, Transource Pennsylvania 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.

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.

Indemnifications and Other Guarantees

Transource Pennsylvania enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, 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. As of December 31, 2025, there were no material liabilities recorded for any indemnifications.

CONTINGENCIES

Insurance and Potential Losses

Transource Pennsylvania maintains property insurance coverage normal and customary for an electric utility, subject to various deductibles. Insurance includes coverage for all risks of physical loss or damage to Transource Pennsylvania property, subject to insurance policy conditions and exclusions. Covered property generally includes substations, facilities and inventories. Excluded property generally includes transmission lines, poles and towers. Transource Pennsylvania's insurance program also generally provides coverage against loss arising from certain claims made by third-parties in excess of retentions absorbed by Transource Pennsylvania. Coverage is generally provided by a combination of various industry mutual and/or commercial insurance carriers.

In April 2025, Transource Pennsylvania renewed insurance programs including coverage for wildfire liability. Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cybersecurity incident, extreme weather or wildfire related liabilities. 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.

6. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-Term Debt

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 Transource Pennsylvania's Long-Term Debt are summarized in the following table:

December 31, 2025		December 31, 2024	
Book Value	Fair Value	Book Value	Fair Value
(in thousands)			
$ 63,200	$ 63,553	$ 60,200	$ 62,667

7. INCOME TAXES

Income Tax Expense

The details of Transource Pennsylvania's income taxes as reported are as follows:

	Years Ended December 31, 2025	2024
	(in thousands)	
Charged (Credited) to Operating Expenses, Net:		
Current	3,236	724
Deferred	(918)	1,103
Total	2,318	1,827
Charged (Credited) to Nonoperating Income, Net:		
Current	48	75
Total	48	75
Income Tax Expense	2,366	1,902

The following is a reconciliation between the federal income taxes computed by multiplying pretax income by the federal statutory tax rate and the income taxes reported:

	Years Ended December 31, 2025		2024	
	(dollars in thousands)			
Net Income	$ 6,012		$ 5,648	
Income Tax Expense	2,366		1,902	
Pretax Income	$ 8,378		$ 7,550	
	Amount	**Percent**	**Amount**	**Percent**
U.S. Federal Statutory Tax Rate	$ 1,759	21.0 %	$ 1,585	21.0 %
State and Local Income Taxes, Net	577	6.9 %	198	2.6 %
Non-Taxable or Non-Deductible Items	29	0.3 %	—	— %
Other Adjustments	1	— %	118	1.6 %
Income Tax Expense	$ 2,366		$ 1,901	
Effective Income Tax Rate	28.2 %		25.2 %	

Net Deferred Tax Asset (Liability)

The following table shows elements of Transource Pennsylvania's net deferred tax assets (liabilities) and significant temporary differences.

	December 31,	
	2025	2024
	(in thousands)	
Deferred Tax Assets	146	156
Deferred Tax Liabilities	(85)	(1,013)
Net Deferred Tax Assets (Liabilities)	61	(857)
Property Related Temporary Differences	(37)	(50)
Regulatory Assets	(78)	(896)
Net Operating Loss Carryforward	—	95
Provision for Refund	179	—
All Other, Net	(3)	(6)
Net Deferred Tax Assets (Liabilities)	61	(857)

8. FINANCING ACTIVITIES

Long-Term Debt

The following table details Long-Term Debt outstanding:

Type of Debt	Maturity	Weighted-Average Interest Rate as of December 31, 2025	Interest Rates as of December 31, 2025	Interest Rates as of December 31, 2024	Outstanding as of December 31, 2025	Outstanding as of December 31, 2024
					(in thousands)	
Intercompany Notes Payable	2028	4.71%	4.71%	5.51%	$ 11,500	$ 10,500
Intercompany Notes Payable	2031	5.15%	5.15%	5.15%	15,904	15,904
Intercompany Notes Payable	2034	5.35%	5.35%	5.35%	15,904	15,904
Intercompany Notes Payable	2050	2.75%	2.75%	—%	2,000	—
Intercompany Notes Payable	2054	5.82%	5.82%	5.82%	17,892	17,892
Total Long-Term Debt					$ 63,200	$ 60,200

Long-Term Debt Subsequent Event

In March 2026, Transource Pennsylvania issued $1.5 million of Intercompany Notes Payable to Transource Energy.

Dividend Restrictions

Transource Pennsylvania pays dividends to Transource Energy provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of Transource Pennsylvania to transfer funds to Transource Energy in the form of dividends.

All of the dividends declared by Transource Pennsylvania 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. As of December 31, 2025, the maximum amount of restricted net assets of Transource Pennsylvania that may not be distributed to Transource Energy in the form of a loan, advance or dividend was $41.7 million.

Members' Equity Subsequent Events

In February 2026, Transource Energy made a $1.8 million contribution to Transource Pennsylvania.

In March 2026, Transource Energy made a $1 million contribution to Transource Pennsylvania.

9. RELATED PARTY TRANSACTIONS

Affiliated Transmission Revenues

Subsidiaries of AEP that are load serving entities within the PJM region incurred $1.5 million and $571 thousand in PJM transmission services costs related to Transource Pennsylvania that were billed to them in accordance with the OATT for the years ended December 31, 2025 and 2024, respectively. Transource Pennsylvania recorded these affiliated transmission revenues in Operating Revenues.

Service Agreements

AEPSC and Evergy Metro, Inc. each provide managerial and professional services to Transource Energy under service agreements. These services agreements are pending the approval of the PAPUC. The costs of the services are billed to Transource Energy by AEPSC and Evergy Metro, Inc., on a direct-charge basis whenever possible and on a reasonable basis of proration for services that benefit multiple companies. The billings for services are made on a cost basis on the same basis as such charges are determined for equivalent services that AEPSC provides to other AEP affiliates and that Evergy Metro, Inc. provides to other Evergy Metro, Inc. affiliates, including reasonable allocations of overhead. Billings from AEPSC and Evergy Metro, Inc. are capitalized or expensed depending on the nature of the services rendered and are recoverable from customers. AEPSC, Evergy Metro, Inc. and their billings are subject to regulation by the FERC under the Public Utility Holding Company Act of 2005. Transource Energy bills Transource Pennsylvania for these services under a service agreement. Transource Pennsylvania's total billings from Transource Energy related to AEPSC services were $2.2 million and $2.1 million for the years ended December 31, 2025 and 2024, respectively. Transource Pennsylvania did not have any billings from Evergy Metro, Inc. for services for the years ended December 31, 2025 and 2024, respectively.

Affiliated Long-Term Debt

For the years ended December 31, 2025 and 2024, Transource Pennsylvania's intercompany borrowings from Transource Energy increased by $3 million and $13 million, respectively. See Note 8 - Financing Activities for additional information.

10. TRANSMISSION PROPERTY

Depreciation

Transource Pennsylvania will provide for depreciation of transmission property on a straight-line basis over the estimated useful lives of property as projects are completed and placed in-service. Transource Pennsylvania's FERC approved composite depreciation rates for depreciable assets range from 1.33% to 20.00%. Transource Pennsylvania had $888 thousand and $747 thousand of depreciable assets in-service as of December 31, 2025 and 2024, respectively.

Asset Retirement Obligations (ARO)

Transource Pennsylvania has identified, but not recognized, ARO liabilities related to electric transmission assets as a result of certain easement agreements for access to assets constructed on property owned by third parties. Generally, such easements are perpetual and require only the retirement and removal of the assets upon the cessation of the property's use. The retirement obligation is not estimable since Transource Pennsylvania plans to use the electric transmission assets indefinitely. The retirement obligation would only be recognized if Transource Pennsylvania abandons or ceases the use of specific easements, which is not expected.

11. REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregated Revenues from Contracts with Customers

Transource Pennsylvania's revenue consists of affiliated and nonaffiliated transmission revenues from contracts with customers. The annual transmission formula rate true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations." Transource Pennsylvania alternative revenues were $(3.3) million and $3 million for the years ended December 31, 2025 and 2024.

Performance Obligations

Transource Pennsylvania 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. Transource Pennsylvania 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 Transource Pennsylvania are summarized as follows:

Transmission Revenues

Transource Pennsylvania has performance obligations to design, develop, construct, operate and maintain transmission plant for the ultimate purpose of transmission of electricity to wholesale customers through assets owned and operated by Transource Pennsylvania. The performance obligation to provide transmission services in each RTO is partially fixed for a period of one year or less. Payments from PJM for transmission services are typically received within one week from the issuance of the invoice, which is issued weekly.

Transource Pennsylvania collects revenues through transmission formula rates. The FERC-approved rates establish the 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.

Contract Assets and Liabilities

Contract assets are recognized when Transource Pennsylvania has 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. Transource Pennsylvania did not have material contract assets as of December 31, 2025 and 2024.

When Transource Pennsylvania receives consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheets in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. Transource Pennsylvania did not have 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 Transource Pennsylvania's balance sheets in Customer Accounts Receivable. Transource Pennsylvania's balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Customer Accounts Receivable were not material as of December 31, 2025 and 2024.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable from Associated Companies on Transource Pennsylvania's balance sheets were not material as of December 31, 2025 and 2024.

Contract Costs

Contract costs to obtain or fulfill a contract for Transource Pennsylvania are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and neither bifurcated nor reclassified between current assets and deferred debits on the 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 Operation Expenses on the statements of income. Transource Pennsylvania did not have material contract costs as of December 31, 2025 and 2024.

12. FERC ORDER NO. 898

On June 29, 2023, the FERC issued Order No. 898 that revised certain aspects of the accounting and reporting requirements under the Uniform System of Accounts. The order created new accounts for wind, solar, and other renewable generating assets, created a new functional class for energy storage accounts, codified the accounting treatment of environmental credits and created new accounts within existing functions for computer hardware, software, and communication equipment. The order is effective January 1, 2025.

The historical balances were transferred to the new accounts in the first quarter of 2025 without restating balances for prior years. The following table presents Transource Pennsylvania's balances transferred as of December 31, 2025, as required by FERC Order No. 898:

Utility Account	Transfers
	(in thousands)
30300 - Intangible Property	$ (1,516)
35120 - Computer Software	11
39721 - Computer Software	1,505
Net Transfers	**$** —

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year									
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)								5,647,861	5,647,861
5	Balance of Account 219 at End of Preceding Quarter/Year									
6	Balance of Account 219 at Beginning of Current Year									
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)								6,012,295	6,012,295
10	Balance of Account 219 at End of Current Quarter/Year									

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	761,638	761,638					
4	Property Under Capital Leases							
5	Plant Purchased or Sold							
6	Completed Construction not Classified	126,263	126,263					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	887,901	887,901					
9	Leased to Others							
10	Held for Future Use							
11	Construction Work in Progress	146,414,876	146,414,876					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	147,302,777	147,302,777					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	405,189	405,189					
15	Net Utility Plant (13 less 14)	146,897,588	146,897,588					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	405,189	405,189					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant							
22	Total in Service (18 thru 21)	405,189	405,189					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	405,189	405,189					

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction					
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)					
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)					
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)					
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents						
4	(303) Miscellaneous Intangible Plant	747,064	9,183			(756,247)	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	747,064	9,183			(756,247)	
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights						
9	(311) Structures and Improvements						
10	(312) Boiler Plant Equipment						
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units						
13	(315) Accessory Electric Equipment						
13.1	(315.1) Computer Hardware						
13.2	(315.2) Computer Software						
13.3	(315.3) Communication Equipment						
14	(316) Misc. Power Plant Equipment						
15	(317) Asset Retirement Costs for Steam Production						
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)						
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						
20	(322) Reactor Plant Equipment						
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
22.1	(324.1) Computer Hardware						
22.2	(324.2) Computer Software						
22.3	(324.3) Communication Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights						
28	(331) Structures and Improvements						
29	(332) Reservoirs, Dams, and Waterways						
30	(333) Water Wheels, Turbines, and Generators						
31	(334) Accessory Electric Equipment						
31.1	(334.1) Computer Hardware						
31.2	(334.2) Computer Software						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
31.3	(334.3) Communication Equipment						
32	(335) Misc. Power Plant Equipment						
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)						
35.1	D. Solar Production Plant						
35.2	(338.1) Land and Land Rights						
35.3	(338.2) Structures and Improvements						
35.5	(338.4) Solar Panels						
35.6	(338.5) Collector System						
35.7	(338.6) Generator Step-up Transformers (GSU)						
35.8	(338.7) Inverters						
35.9	(338.8) Other Accessory Electrical Equipment						
35.10	(338.9) Computer Hardware						
35.11	(338.10) Computer Software						
35.12	(338.11) Communication Equipment						
35.13	(338.12) Miscellaneous Power Plant Equipment						
35.14	(338.13) Asset Retirement Costs for Solar Production						
35.15	TOTAL Solar Production Plant (Enter Total of lines 35.2 thru 35.14)						
35.16	E. Wind Production Plant						
35.17	(338.20) Land and Land Rights						
35.18	(338.21) Structures and Improvements						
35.20	(338.23) Wind Turbines						
35.21	(338.24) Wind Towers and Fixtures						
35.23	(338.26) Collector System						
35.24	(338.27) Generator Step-up Transformers (GSU)						
35.25	(338.28) Inverters						
35.26	(338.29) Other Accessory Electrical Equipment						
35.27	(338.30) Computer Hardware						
35.28	(338.31) Computer Software						
35.29	(338.32) Communication Equipment						
35.30	(338.33) Miscellaneous Power Plant Equipment						
35.31	(338.34) Asset Retirement Costs for Wind Production						
35.32	TOTAL Wind Production Plant (Enter Total of lines 35.17 thru 35.31)						
35.33	F. Other Renewable Production Plant						
35.34	(339.1) Land and Land Rights						
35.35	(339.2) Structures and Improvements						
35.36	(339.3) Fuel Holders						
35.37	(339.4) Boilers						
35.39	(339.6) Generators						
35.41	(339.8) Other Accessory Electrical Equipment						
35.42	(339.9) Computer Hardware						
35.43	(339.10) Computer Software						
35.44	(339.11) Communication Equipment						
35.45	(339.12) Miscellaneous Power Plant Equipment						
35.46	(339.13) Asset Retirement Costs for Other Renewable Production						
35.47	TOTAL Other Renewable Production Plant (Enter Total of lines 35.34 thru 35.46)						
36	G. Other Production Plant						
37	(340) Land and Land Rights						
38	(341) Structures and Improvements						
39	(342) Fuel Holders, Products, and Accessories						
40	(343) Prime Movers						
41	(344) Generators						
42	(345) Accessory Electric Equipment						
42.1	(345.1) Computer Hardware						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
42.2	(345.2) Computer Software						
42.3	(345.3) Communication Equipment						
43	(346) Misc. Power Plant Equipment						
44	(347) Asset Retirement Costs for Other Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)						
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32, 35.47, and 45)						
47	3. Transmission Plant						
48	(350) Land and Land Rights						
48.2	(351.1) Computer Hardware						
48.3	(351.2) Computer Software		183,608			5,277	188,885
48.4	(351.3) Communication Equipment						
49	(352) Structures and Improvements						
50	(353) Station Equipment						
51	(354) Towers and Fixtures						
52	(355) Poles and Fixtures						
53	(356) Overhead Conductors and Devices						
54	(357) Underground Conduit						
55	(358) Underground Conductors and Devices						
56	(359) Roads and Trails						
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)		183,608			5,277	188,885
59	4. Distribution Plant						
60	(360) Land and Land Rights						
61	(361) Structures and Improvements						
62	(362) Station Equipment						
63.1	(363.1) Computer Hardware						
63.2	(363.2) Computer Software						
63.3	(363.3) Communication Equipment						
64	(364) Poles, Towers, and Fixtures						
65	(365) Overhead Conductors and Devices						
66	(366) Underground Conduit						
67	(367) Underground Conductors and Devices						
68	(368) Line Transformers						
69	(369) Services						
70	(370) Meters						
71	(371) Installations on Customer Premises						
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems						
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)						
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
84.1	6. ENERGY STORAGE PLANT						
84.2	(387.1) Land and Land Rights						
84.3	(387.2) Structures and Improvements						
84.4	(387.3) Energy Storage Equipment						
84.6	(387.5) Collector System						
84.7	(387.6) Generator Step-up Transformers (GSU)						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
84.8	(387.7) Inverters						
84.9	(387.8) Computer Hardware						
84.10	(387.9) Computer Software						
84.11	(387.10) Communication Equipment						
84.12	(387.11) Miscellaneous Energy Storage Equipment						
84.13	(387.12) Asset Retirement Costs for Energy Storage						
84.14	TOTAL Energy Storage Plant (Total lines 84.2 thru 84.13)						
85	7. General Plant						
86	(389) Land and Land Rights						
87	(390) Structures and Improvements						
88	(391) Office Furniture and Equipment						
89	(392) Transportation Equipment						
90	(393) Stores Equipment						
91	(394) Tools, Shop and Garage Equipment						
92	(395) Laboratory Equipment						
93	(396) Power Operated Equipment						
94	(397.1) Computer Hardware						
94.1	(397.2) Computer Software		96,326	148,280		750,970	699,016
94.2	(397.3) Communication Equipment						
95	(398) Miscellaneous Equipment						
96	SUBTOTAL (Enter Total of lines 86 thru 95)		96,326	148,280		750,970	699,016
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)		96,326	148,280		750,970	699,016
100	TOTAL (Accounts 101 and 106)	747,064	289,117	148,280			887,901
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	747,064	289,117	148,280			887,901

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL					

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	TOTAL			

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	IEC Project Pennsylvania	88,275,778
2	Transource Station Work	58,043,584
3	Other Minor Projects Which is under 5% or $1,000,000	95,514
43	Total	146,414,876

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year				
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	170,825	170,825		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	(12,262)	(12,262)		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	158,563	158,563		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(148,280)	(148,280)		
13	Cost of Removal				
14	Salvage (Credit)				
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(148,280)	(148,280)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	394,905	394,905		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	405,188	405,188		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
23.1	Solar Production				
23.2	Wind Production				
23.3	Other Renewable Production				
24	Other Production				
25	Transmission	28,405	28,405		
26	Distribution				
27	Regional Transmission and Market Operation				
27.1	Energy Storage				
28	General	376,783	376,783		
29	TOTAL (Enter Total of lines 20 thru 28)	405,188	405,188		

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								
41								

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
42	Total Cost of Account 123.1 $		Total					

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)			
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)			
9	Distribution Plant (Estimated)			
10	Regional Transmission and Market Operation Plant (Estimated)			
10.1	Energy Storage Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)			
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies			

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

Allowances and Environmental Credits (Accounts 158.1, 158.2, 158.3, and 158.4)

1. Report below the details related to allowances and environmental credits. Additional information about the type of allowances/environmental credits required by other regulatory bodies can be disclosed within the footnote data.
2. Report all acquisitions of allowances and environmental credits at cost.
3. Report allowances and environmental credits in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances and environmental credits transactions by the period they are first eligible for use: the current year's allowances and environmental credits in columns (b)-(c), allowances and environmental credits for the three succeeding years in columns (d)-(i), starting with the following year, and allowances and environmental credits for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 authoritative agency issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by an authoritative agency. Report on Line 39 the authoritative agency's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the authoritative agency's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances and environmental credits acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances and environmental credits disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance and environmental credits sales.

Line No.	Allowances and Environmental Credits Inventory (Accounts 158.1, 158.3, and 158.4) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year												
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by authoritative agency												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509, 555.2, and 555.3												
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year												
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by authoritative agency												

Line No.	Allowances and Environmental Credits Inventory (Accounts 158.1, 158.3, and 158.4) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
38	Deduct: Returned by authoritative agency												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20	Total				
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39	Total				
40	Grand Total				

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	SFAS 109 Deferred FIT					
2	PJM Transmission True Up, Amortization Period: 01/2025 - 12/2025	2,175,596	99,360		2,274,956	
3	PJM Transmission True-Up, Amortization Period: 01/2026 - 12/2026	1,417,720	1,022,101	421, 456	2,127,175	312,646
4	PJM Transmission True-Up, Amortization Period: 01/2027-12/2027					
44	TOTAL	3,593,316	1,121,461		4,402,131	312,646

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Unamortized Credit Line FeesAmortizing through September 2025	59,974		428	59,974	
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	59,974				

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	PT Method/Life - NORM	2,328	362
3	2020 712L 481(a) Software	(1,424)	
4	INSURANCE PREMIUMS ACCRUED	(4,220)	(3,842)
5	REG ASSET-FERC Formula Rates Under Recvr	37,654	3,276
6	NOL-STATE C/F-DEF TAX ASSET-L/T - PA	120,679	
7	Other	1,213	146,184
8	TOTAL Electric (Enter Total of lines 2 thru 7)	156,230	145,980
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	156,230	145,980

Notes

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2										
3										
4										
5	Total									
6	Preferred Stock (Account 204)									
7										
8										
9										
10	Total									

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2026-04-14	Year/Period of Report End of: 2025/ Q4

Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
c. Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
d. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	32,120,463
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	2,500,000
4	Ending Balance Amount	34,620,463
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	6,492,649
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	585,955
16	Ending Balance Amount	7,078,604
17	**Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	41,699,067

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a)principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2													
3													
4													
5	Subtotal												
6	Reacquired Bonds (Account 222)												
7													
8													
9													
10	Subtotal												
11	Advances from Associated Companies (Account 223)												
12	Private placement 5.15%		15,904,000					11/14/2024	11/14/2031	11/14/2024	11/14/2031	[a]15,904,000	819,056
13	Private placement 5.35%		15,904,000					11/14/2024	11/14/2034	11/14/2024	11/14/2034	15,904,000	850,864
14	Private placement 5.82%		17,892,000					11/14/2024	11/14/2054	11/14/2024	11/14/2054	17,892,000	1,041,314
15	Private Placement 2.75%		2,000,000					10/27/2025	03/31/2050	10/27/2025	03/31/2050	2,000,000	9,778
16	Notes Payable to Afffiliated Company - Transource Energy, LLCFERC Authority (Docket No. ES25-21-000) for Transource Pennsylvania, LLC.		200,000,000					02/20/2025	02/20/2028	02/20/2025	02/20/2028	11,500,000	560,440
17	Subtotal		251,700,000									63,200,000	3,281,452
18	Other Long Term Debt (Account 224)												
19													
20													
21													
22	Subtotal												
33	TOTAL		251,700,000	438,665								63,200,000	[b]3,281,452

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: AdvancesFromAssociatedCompanies
Fees related to this credit facility are now part of the new credit facility fees being amortized until 2023.
(b) Concept: InterestExpenseOnLongTermDebtIssued
The difference between the total interest on this schedule and the total of account 430 is due to interest on short-term advances from the AEP Money Pool.

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	6,012,295
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	12,579,877
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: FederalTaxNetIncome

Net Income for the Year per Page 117	6,012
Federal Income Taxes	1,635
State Income Taxes	730
Pre-Tax Book Income	8,377
Increase (Decrease) in Taxable Income resulting from:	
Allowance for Funds Used During Construction and Other Differences	
Excess Tax vs Book Depreciation	52
Book Accruals	11
Book Deferrals	3,281
Tax Deferrals	—
Revenue Refunds	718
Other	141
Federal Taxable Income before State Income Taxes	12,580
Less: State Income Taxes	812
Federal Tax Net Income - Estimated Current Year Taxable Income	11,768
Computation of Tax *	
Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at the Statutory Rate of 21%	2,471
NOL Reclass	—
Estimated Current Federal Income Taxes (Net)	2,471
Adjustments of Prior year's Accruals (Net)	—
Estimated Current Federal Income Taxes(Net)	2,471

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	Real & Pers Prop	Property Tax	PA		(4,915)		21,268	16,354				21,268			
2	**Subtotal Property Tax**				(4,915)		21,268	16,354				21,268			
3	Use Tax	Sales And Use Tax	PA		94,288					94,288					
4	**Subtotal Sales And Use Tax**				94,288					94,288					
5	Federal Income	Income Tax			3,200,255		2,027,814			5,228,069		2,437,766			(409,952)
6	Federal Income	Income Tax	PA		(2,755,065)					(2,755,065)					
7	State Income Tax	Income Tax	PA		133,988		669,683			803,670		797,660			(127,977)
8	**Subtotal Income Tax**				579,177		2,697,497			3,276,674		3,235,426			(537,929)
40	TOTAL				668,551		2,718,766	16,354		3,370,963		3,256,694			(537,929)

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%				411.4					
3	4%				411.4					
4	7%				411.4					
5	10%		411.1		411.4					
6	State DITC		411.1		411.4					
7	30%				411.4					
8	TOTAL Electric (Enter Total of lines 2 thru 7)							1		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL									

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Other Deferred Credits					
47	TOTAL					

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other - SFAS 109						254		254		
17	TOTAL (Acct 281) (Total of 8, 15 and 16)										
18	Classification of TOTAL										
19	Federal Income Tax										
20	State Income Tax										
21	Local Income Tax										

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	42,411	119,751	130,624					254		31,538
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	42,411	119,751	130,624							31,538
6	Other						1823/254		1823/254		
9	TOTAL Account 282 (Total of Lines 5 thru 8)	42,411	119,751	130,624							31,538
10	Classification of TOTAL										
11	Federal Income Tax	42,411	119,751	130,624							31,538
12	State Income Tax										
13	Local Income Tax										

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	PT Method/Life - NORM	11,085	836	10,200							1,721
4	2020 712L 481(a) Software	(6,779)	6,779								
5	INSURANCE PREMIUMS ACCRUED	1,055	3,841	3,936							960
6	REG ASSET-FERC Formula Rates Under Recvr	933,903	1,765	854,411							81,257
7	NOL-STATE C/F-DEF TAX ASSET-L/T - PA	25,343	1,079	26,422							
8	Other	5,772	10,773	47,029							(30,484)
9	TOTAL Electric (Total of lines 3 thru 8)	970,379	25,073	941,998							53,454
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other						1823/254		1823/254		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	970,379	25,073	941,998							53,454
20	Classification of TOTAL										
21	Federal Income Tax	1,016,481	2,505	716,789				236,542			65,655
22	State Income Tax	(46,102)	22,568	225,209				(236,542)			(12,201)
23	Local Income Tax										

NOTES

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	SFAS 109 Deferred FIT					
41	TOTAL					

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

Electric Operating Revenues

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales						
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)						
5	Large (or Ind.) (See Instr. 4)						
6	(444) Public Street and Highway Lighting						
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers						
11	(447) Sales for Resale						
12	TOTAL Sales of Electricity						
13	(Less) (449.1) Provision for Rate Refunds	722,848					
14	TOTAL Revenues Before Prov. for Refunds	(722,848)					
15	Other Operating Revenues						
16	(450) Forfeited Discounts						
17	(451) Miscellaneous Service Revenues						
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	1,703					
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues						
22	(456.1) Revenues from Transmission of Electricity of Others	[a]12,472,292	11,306,683				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	12,473,995	11,306,683				
27	TOTAL Electric Operating Revenues	11,751,147	11,306,683				

Line12, column (b) includes $ of unbilled revenues.
Line12, column (d) includes MWH relating to unbilled revenues

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: RevenuesFromTransmissionOfElectricityOfOthers

Reference page 328 for Revenue details.

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		722,848			

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed - All Accounts					
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts					
43	TOTAL - All Accounts					

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.

   SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

   LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

   OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

   AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the last line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
1											
2											
3											
4											
5											
6											
7											
8											
9											
10											
11											
12											
13											
14											
15	Subtotal - RQ										
16	Subtotal-Non-RQ										
17	Total										

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
18.1	(513.1) Maintenance of Computer Hardware		
18.2	(513.2) Maintenance of Computer Software		
18.3	(513.3) Maintenance of Communication Equipment		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)		
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
38.1	(531.1) Maintenance of Computer Hardware		
38.2	(531.2) Maintenance of Computer Software		
38.3	(531.3) Maintenance of Communication Equipment		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
56.1	(544.1) Maintenance of Computer Hardware		
56.2	(544.2) Maintenance of Computer Software		
56.3	(544.3) Maintenance of Communication Equipment		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of Lines 62 thru 67)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
71.1	(553.1) Maintenance of Computer Hardware		
71.2	(553.2) Maintenance of Computer Software		
71.3	(553.3) Maintenance of Communication Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power		
76.1	(555.1) Power Purchased for Storage Operations		
76.2	(555.2) Bundled Environmental Credits		
76.3	(555.3) Unbundled Environmental Credits		
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)		
79.1	F. Solar Generation		
79.2	Operation		
79.3	(558.1) Operation Supervision and Engineering		
79.4	(558.2) Solar Panel Generation and Other Plant Operating Expenses		
79.6	(558.4) Rents		
79.7	TOTAL Operation (Enter Total of lines 79.3 thru 79.6)		
79.8	Maintenance		
79.9	(558.6) Maintenance Supervision and Engineering		
79.10	(558.7) Maintenance of Solar Panels, Structures, and Equipment		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
79.11	(558.8) Maintenance of Computer Hardware		
79.12	(558.9) Maintenance of Computer Software		
79.13	(558.10) Maintenance of Communication Equipment		
79.14	(558.11) Maintenance of Miscellaneous Solar Generation Plant		
79.15	TOTAL Maintenance (Enter Total of lines 79.9 thru 79.14)		
79.16	TOTAL Power Production Expenses-Solar (total of lines 79.7 & 79.15)		
79.17	G. Wind Generation		
79.18	Operation		
79.19	(558.13) Operation Supervision and Engineering		
79.20	(558.14) Wind Turbine Generation and Other Plant Operating Expenses		
79.21	(558.16) Rents		
79.22	TOTAL Operation (Enter Total of lines 79.19 thru 79.21)		
79.23	Maintenance		
79.24	(558.18) Maintenance Supervision and Engineering		
79.25	(558.19) Maintenance of Wind Turbines, Structures, and Equipment		
79.26	(558.20) Maintenance of Computer Hardware		
79.27	(558.21) Maintenance of Computer Software		
79.28	(558.22) Maintenance of Communication Equipment		
79.29	(558.23) Maintenance of Miscellaneous Wind Generation Plant		
79.30	TOTAL Maintenance (Enter Total of lines 79.24 thru 79.29)		
79.31	TOTAL Power Production Expenses-Wind (total of lines 79.22 & 79.30)		
79.32	H. Other Renewable Generation		
79.33	Operation		
79.34	(559.1) Operation Supervision and Engineering		
79.35	(559.2) Other Miscellaneous Generation and Other Plant Operating Expenses		
79.36	(559.3) Fuel		
79.37	(559.4) Rents		
79.38	TOTAL Operation (Enter Total of lines 79.34 thru 79.37)		
79.39	Maintenance		
79.40	(559.6) Maintenance Supervision and Engineering		
79.41	(559.7) Maintenance of Structures		
79.42	(559.9) Maintenance of Boilers		
79.43	(559.10) Maintenance of Generating and Electric Equipment		
79.44	(559.12) Maintenance of Computer Hardware		
79.45	(559.13) Maintenance of Computer Software		
79.46	(559.14) Maintenance of Communication Equipment		
79.47	(559.15) Maintenance of Miscellaneous Renewable Production Plant		
79.48	TOTAL Maintenance (Enter Total of lines 79.40 thru 79.47)		
79.49	TOTAL Power Production Expenses-Other Renewable (total of lines 79.38 & 79.48)		
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74, 79, 79.16, 79.31, & 79.49)		
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	137,006	(489,138)
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	657	635
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	3,010	2,977
90	(561.6) Transmission Service Studies	1	
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses		
94	(563) Overhead Lines Expenses	477	992
95	(564) Underground Lines Expenses		3
96	(565) Transmission of Electricity by Others		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
97	(566) Miscellaneous Transmission Expenses	65,710	53,403
98	(567) Rents		
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	206,861	(431,128)
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	17	1
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	234	413
104	(569.2) Maintenance of Computer Software	15,198	20,603
105	(569.3) Maintenance of Communication Equipment		78
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	329	428
108	(571) Maintenance of Overhead Lines	7,185	189
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	1,661	41
111	TOTAL Maintenance (Total of Lines 101 thru 110)	24,624	21,753
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	231,485	(409,375)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)		
131.1	4. ENERGY STORAGE EXPENSES		
131.2	Operation		
131.3	(577.1) Operation Supervision and Engineering		
131.4	(577.2) Operation of Energy Storage Equipment		
131.5	(577.3) Storage Fuel		
131.6	(577.4) Rents		
131.7	Total Operation (Lines 131.3 thru 131.6)		
131.8	Maintenance		
131.9	(578.1) Maintenance Supervision and Engineering		
131.10	(578.2) Maintenance of Energy Storage Equipment and Structures		
131.11	(578.3) Maintenance of Computer Hardware		
131.12	(578.4) Maintenance of Computer Software		
131.13	(578.5) Maintenance of Communication Equipment		
131.14	(578.6) Maintenance of Miscellaneous Other Energy Storage Plant		
131.15	Total Maintenance (Lines 131.9 thru 131.14)		
131.16	TOTAL Energy Storage Expenses (Total of 131.7 and 131.15)		
132	5. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering		
135	(581) Load Dispatching		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
136	(582) Station Expenses		
137	(583) Overhead Line Expenses		
138	(584) Underground Line Expenses		
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses		
141	(587) Customer Installations Expenses		
142	(588) Miscellaneous Expenses		
143	(589) Rents		
144	TOTAL Operation (Enter Total of Lines 134 thru 143)		
145	Maintenance		
146	(590) Maintenance Supervision and Engineering		
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment		
148.1	(592.2) Maintenance of Computer Hardware		
148.2	(592.3) Maintenance of Computer Software		
148.3	(592.4) Maintenance of Communication Equipment		
149	(593) Maintenance of Overhead Lines		
150	(594) Maintenance of Underground Lines		
151	(595) Maintenance of Line Transformers		
152	(596) Maintenance of Street Lighting and Signal Systems		
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of Lines 146 thru 154)		
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)		
157	6. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses		
161	(903) Customer Records and Collection Expenses		
162	(904) Uncollectible Accounts		
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)		
165	7. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses		
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)		
172	8. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)		
179	9. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	120,123	247,725
182	(921) Office Supplies and Expenses	7,043	2,088
183	(Less) (922) Administrative Expenses Transferred-Credit	21,206	58,384
184	(923) Outside Services Employed	(568,581)	700,492
185	(924) Property Insurance		
186	(925) Injuries and Damages	11	21
187	(926) Employee Pensions and Benefits	1	21

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	29,607	12,467
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	4	
192	(930.2) Miscellaneous General Expenses	1,019	364
193	(931) Rents		
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	(431,979)	904,794
195	Maintenance		
196	(935) Maintenance of General Plant	158	295
196.1	(935.1) Maintenance of Computer Hardware	345	
196.2	(935.2) Maintenance of Computer Software	5,493	
196.3	(935.3) Maintenance of Communication Equipment	35	
196.4	TOTAL Maintenance (Enter Total of lines 196 thru 196.3)	6,031	295
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196.4)	(425,948)	905,089
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 131.16, 156, 164, 171, 178, and 197)	(194,463)	495,714
	Page 320-323		

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

   SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

   LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

   EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

   OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote for each adjustment.

   AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
1														
2														
3														
4														
5														
6														
7														
8														
9														
10														
11														
12														
13														
14														
15	TOTAL						0	0	0	0				

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	PJM			FNO	PJM OATT								12,472,292 (a)	12,472,292
35	TOTAL												12,472,292	12,472,292

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Revenue earned from PJM per the revenue requirement for transmission services filed with FERC.

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL							

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Trustee fee	
7	Company Membership	18
8	Travel Expenses	507
9	Miscellaneous expenses	494
46	TOTAL	1,019

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

1. Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
   Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
   For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant					
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
5.1	Solar Production Plant					
5.2	Wind Production Plant					
5.3	Other Renewable Production Plant					
6	Other Production Plant					
7	Transmission Plant	28,449				28,449
8	Distribution Plant					
9	Regional Transmission and Market Operation					
9.1	Energy Storage Plant					
10	General Plant	142,376				142,376
11	Common Plant-Electric					
12	TOTAL	170,825				170,825

B. Basis for Amortization Charges

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	TRANSMISSION						
13	351.2	0.165					
14	TOTAL TRANSMISSION	0.165					
15	GENERAL PLANT						
16	397.2	0.661					
17	397.2 MAX	0.017					
18	TOTAL GENERAL PLANT	0.678					
19	DEPRECIABLE SUM	0.843					

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	Miscellaneous Expenses		29,607	29,607			928	29,607				
46	TOTAL		29,607	29,607				29,607				

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:

   A. Electric R, D and D Performed Internally:

      1. Generation
         a. hydroelectric
            i. Recreation fish and wildlife
            ii. Other hydroelectric
         b. Fossil-fuel steam
         c. Internal combustion or gas turbine
         d. Nuclear
         e. Solar
         f. Wind
         g. Other renewable
         h. Unconventional generation
         i. Siting and heat rejection
      2. Transmission
         a. Overhead
         b. Underground
      3. Distribution
      4. Regional Transmission and Market Operation
      5. Energy Storage
      6. Environment (other than equipment)
      7. Other (Classify and include items in excess of $50,000.)
      8. Total Cost Incurred

   B. Electric, R, D and D Performed Externally:

      1. Research Support to the electrical Research Council or the Electric Power Research Institute
      2. Research Support to Edison Electric Institute
      3. Research Support to Nuclear Power Groups
      4. Research Support to Others (Classify)
      5. Total Cost Incurred

3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	B(1): Research Support to Electrical	3 items under $50,000		2	566	2	
2	Research Council or the Electric						
3	Power Research Institute						

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production			
4	Transmission			
5	Regional Market			
5.1	Energy Storage			
6	Distribution			
7	Customer Accounts			
8	Customer Service and Informational			
9	Sales			
10	Administrative and General			
11	TOTAL Operation (Enter Total of lines 3 thru 10)			
12	Maintenance			
13	Production			
14	Transmission			
15	Regional Market			
15.1	Energy Storage			
16	Distribution			
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)			
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)			
21	Transmission (Enter Total of lines 4 and 14)			
22	Regional Market (Enter Total of Lines 5 and 15)			
22.1	Energy Storage (Enter Total of Lines 5.1 and 15.1)			
23	Distribution (Enter Total of lines 6 and 16)			
24	Customer Accounts (Transcribe from line 7)			
25	Customer Service and Informational (Transcribe from line 8)			
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)			
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)			
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)			
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant			
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)			
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts			
96	TOTAL SALARIES AND WAGES			

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchase Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
46	TOTAL				

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total				0	0	0	0	0	0

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2026-04-14	Year/Period of Report End of: 2025/ Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
6.1	Solar		27	Total Energy Losses	
6.2	Wind		27.1	Total Energy Stored	
6.3	Other Renewable		28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	0
7	Other				
8	Less Energy for Pumping				
9	Net Generation (Enter Total of lines 3 through 8)	0			
10	Purchases (other than for Energy Storage)	0			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	0			

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 0					
29	January					
30	February					
31	March					
32	April					
33	May					
34	June					
35	July					
36	August					
37	September					
38	October					
39	November					
40	December					
41	Total	0	0			

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: 0
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0
7	Plant Hours Connected to Load	0
8	Net Continuous Plant Capability (Megawatts)	0
9	When Not Limited by Condenser Water	0
10	When Limited by Condenser Water	0
11	Average Number of Employees	0
12	Net Generation, Exclusive of Plant Use - kWh	0
13	Cost of Plant: Land and Land Rights	0
14	Structures and Improvements	0
15	Equipment Costs	0
16	Asset Retirement Costs	0
17	Total Cost (10-23)	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0
19	Production Expenses: Oper, Supv, & Engr	0
20	Fuel	0
21	Coolants and Water (Nuclear Plants Only)	0
22	Steam Expenses	0
23	Steam From Other Sources	0
24	Steam Transferred (Cr)	0
25	Electric Expenses	0
26	Misc Steam (or Nuclear) Power Expenses	0
27	Rents	0
28	Allowances	0
29	Maintenance Supervision and Engineering	0
30	Maintenance of Structures	0
31	Maintenance of Boiler (or reactor) Plant	0
32	Maintenance of Electric Plant	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0
34	Total Production Expenses	0
35	Expenses per Net kWh	0.0000

35	**Plant Name**
36	Fuel Kind
37	Fuel Unit
38	Quantity (Units) of Fuel Burned
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year
41	Average Cost of Fuel per Unit Burned
42	Average Cost of Fuel Burned per Million BTU
43	Average Cost of Fuel Burned per kWh Net Gen
44	Average BTU per kWh Net Generation

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Kind of Plant (Run-of-River or Storage)	
2	Plant Construction type (Conventional or Outdoor)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total installed cap (Gen name plate Rating in MW)	0
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0
7	Plant Hours Connect to Load	0
8	**Net Plant Capability (in megawatts)**	
9	(a) Under Most Favorable Oper Conditions	0
10	(b) Under the Most Adverse Oper Conditions	0
11	Average Number of Employees	0
12	Net Generation, Exclusive of Plant Use - kWh	0
13	**Cost of Plant**	
14	Land and Land Rights	0
15	Structures and Improvements	0
16	Reservoirs, Dams, and Waterways	0
17	Equipment Costs	0
18	Roads, Railroads, and Bridges	0
19	Asset Retirement Costs	0
20	Total Cost (10-23)	0
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	**Production Expenses**	
23	Operation Supervision and Engineering	0
24	Water for Power	0
25	Hydraulic Expenses	0
26	Electric Expenses	0
27	Misc Hydraulic Power Generation Expenses	0
28	Rents	0
29	Maintenance Supervision and Engineering	0
30	Maintenance of Structures	0
31	Maintenance of Reservoirs, Dams, and Waterways	0
32	Maintenance of Electric Plant	0
33	Maintenance of Misc Hydraulic Plant	0
34	Total Production Expenses (total 23 thru 33)	0
35	Expenses per net kWh	0

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	**Cost of Plant**	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total Cost (10-23)	
22	Cost per KW of installed cap (line 21 / 4)	
23	**Production Expenses**	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants, pumped storage plants, and renewable plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, renewable, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
1													
2													
3													
4													
5													
6													
7													
8													
9													
10													
11													
12													
13													
14													
15													
16													
17													
18													
19													
20													
21													
22													
23													
24													
25													
26													
27													
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													
38													
39													
40													
41													

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
42													
43													
44													
45													
46													

Page 410-411

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) and (b) report the name of the energy storage project and location.
3. In column (c), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In column (d) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (c) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In column (e) report MWHs lost during conversion, storage and discharge of energy.
6. In column (f) report the MWHs sold.
7. In column (g), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (h), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (i) and (j), report fuel costs for storage operations associated with self-generated power and other costs associated with self-generated power.
9. In column (l) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	MWHs (c)	MWHs delivered to the grid (d)	MWHs Lost During Conversion, Storage and Discharge of Energy (e)	MWHs Sold (f)	Revenues from Energy Storage Operations (g)	Power Purchased for Storage Operations (555.1) (Dollars) (h)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (i)	Other Costs Associated with Self-Generated Power (Dollars) (j)	Account for Project Costs (k)	Total Project Plant Costs (l)
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
13												
14												
15												
16												
17												
18												
19												
20												
21												
22												
23												
24												
25												
26												
27												
28												
29												
30												
31												
32												
33												
34												
35	TOTAL		0	0	0	0	0	0	0	0		0

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a) and (b) report the name of the energy storage project, and location.
3. In column (c), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (d), report operation expenses excluding fuel, (e), maintenance expenses, (f) fuel costs for storage operations and (g) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (h) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	Project Cost (c)	Plant Operating Expenses				
				Operations (Excluding Fuel used in Storage Operations) (d)	Maintenance (e)	Cost of fuel used in storage operations (f)	Account No. 555.1, Power Purchased for Storage Operations (g)	Other Expenses (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36	TOTAL							

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltag lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amo of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnis succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, an how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated compa
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AN TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Tota Expen
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	NOTHING TO REPORT															
36	TOTAL					0	0	0								

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, i column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	NOTHING TO REPORT																
44	TOTAL		0		0	0	0										

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
13												
14												
15												
16												
17												
18												
19												
20												
21												
22												
23												
24												
25												
26												
27												
28												
29												
30												
31												
32												
33												
34												
35												
36												
37												
38												

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
39												
40												
2	TotalTransmissionSubstationMember											0
3	Total											0
Page 426-427												

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2026	Year/Period of Report End of: 2025/ Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	AEP Transmission	AEPSC	920, 923	(567,556)
3	Construction Services	AEPSC	107, 108	2,238,518
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

APPENDIX 4

APPENDIX 5

APPENDIX 6

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended **December 31, 2025**
or
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____ to_____

Commission File Number	Registrants; Address and Telephone Number	States of Incorporation	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER CO INC.	New York	13-4922640
333-221643	AEP TEXAS INC.	Delaware	51-0007707
333-217143	AEP TRANSMISSION COMPANY, LLC	Delaware	46-1125168
1-3457	APPALACHIAN POWER COMPANY	Virginia	54-0124790
1-3570	INDIANA MICHIGAN POWER COMPANY	Indiana	35-0410455
1-6543	OHIO POWER COMPANY	Ohio	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA	Oklahoma	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY	Delaware	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215-2373 Telephone (614) 716-1000		

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Trading Symbol	Name of Each Exchange on Which Registered
American Electric Power Company Inc.	Common Stock, $6.50 par value	AEP	The NASDAQ Stock Market LLC

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if AEP Texas Inc., AEP Transmission Company, LLC and Public Service Company of Oklahoma, are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.	Yes	☒	No	☐
Indicate by check mark if American Electric Power Company, Inc., Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company and Southwestern Electric Power Company are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.	Yes	☐	No	☒
Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.	Yes	☐	No	☒
Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.	Yes	☒	No	☐
Indicate by check mark whether the registrants have submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).	Yes	☒	No	☐

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer	☒	Accelerated filer	☐	Non-accelerated filer	☐
Smaller reporting company	☐	Emerging growth company	☐		

Indicate by check mark whether AEP Texas Inc., AEP Transmission Company, LLC, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, non-accelerated filers, smaller reporting companies, or emerging growth companies. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer	☐	Accelerated filer	☐	Non-accelerated filer	☒
Smaller reporting company	☐	Emerging growth company	☐		

If an emerging growth company, indicate by check mark if the registrants have elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

AEP Texas Inc., AEP Transmission Company, LLC, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

	Aggregate Market Value of Voting and Non-Voting Common Equity Held by Nonaffiliates of the Registrants as of June 30, 2025 the Last Trading Date of the Registrants' Most Recently Completed Second Fiscal Quarter	Number of Shares of Common Stock Outstanding of the Registrants as of December 31, 2025
American Electric Power Company, Inc.	$56,119,786,438	540,861,473
		($6.50 par value)
AEP Texas Inc.	None	100
		($0.01 par value)
AEP Transmission Company, LLC (a)	None	NA
Appalachian Power Company	None	13,499,500
		(no par value)
Indiana Michigan Power Company	None	1,400,000
		(no par value)
Ohio Power Company	None	27,952,473
		(no par value)
Public Service Company of Oklahoma	None	9,013,000
		($15 par value)
Southwestern Electric Power Company	None	3,680
		($18 par value)

(a) 100% interest is held by AEP Transmission Holdco.
NA Not applicable.

Note on Market Value of Common Equity Held by Nonaffiliates

American Electric Power Company, Inc. owns all of the common stock of AEP Texas Inc., Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company and, indirectly, all of the LLC membership interest in AEP Transmission Company, LLC (see Item 12 herein).

Documents Incorporated By Reference

Description	Part of Form 10-K into which Document is Incorporated
Portions of Proxy Statement of American Electric Power Company, Inc. for 2026 Annual Meeting of Shareholders.	Part III

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

You can access financial and other information at AEP's website, including AEP's Principles of Business Conduct, certain committee charters and Principles of Corporate Governance. The address is www.AEP.com. Investors can obtain copies of our SEC filings from this site free of charge, as well as from the SEC website at www.sec.gov.

TABLE OF CONTENTS

Item Number		Page Number
	Glossary of Terms	i
	Forward-Looking Information	vii
	PART I	
1	**Business**	
	General	1
	Business Segments	6
	Vertically Integrated Utilities	6
	Transmission and Distribution Utilities	13
	AEP Transmission Holdco	14
	Generation & Marketing	17
	Executive Officers of AEP	18
1A	**Risk Factors**	19
1B	**Unresolved Staff Comments**	31
1C	**Cybersecurity**	31
2	**Properties**	33
	Generation Facilities	33
	Transmission and Distribution Facilities	35
	Title to Property	35
	System Transmission Lines and Facility Siting	35
	Construction Program	36
	Potential Uninsured Losses	36
3	**Legal Proceedings**	37
4	**Mine Safety Disclosure**	37
	PART II	
5	**Market for Registrants' Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities**	38
6	**Reserved**	39
7	**Management's Discussion and Analysis of Financial Condition and Results of Operations**	39
7A	**Quantitative and Qualitative Disclosures about Market Risk**	39
8	**Financial Statements and Supplementary Data**	39
9	**Changes in and Disagreements with Accountants on Accounting and Financial Disclosure**	337
9A	**Controls and Procedures**	337
9B	**Other Information**	337
9C	**Disclosure Regarding Foreign Jurisdictions that Prevent Inspections**	337
	PART III	
10	**Directors, Executive Officers and Corporate Governance**	338
11	**Executive Compensation**	338
12	**Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters**	339
13	**Certain Relationships and Related Transactions and Director Independence**	339
14	**Principal Accounting Fees and Services**	340
	PART IV	
15	**Exhibits and Financial Statement Schedules**	
	Financial Statements	341
16	Form 10-K Summary	342
	Signatures	343
	Index of Financial Statement Schedules	S-1
	Exhibit Index	E-1

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/.

Company Website and Availability of SEC Filings

Our principal corporate website address is www.aep.com. Information on our website is not incorporated by reference herein and is not part of this Form 10-K. We make available free of charge through our website our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such documents are electronically filed with, or furnished to, the SEC. The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements and other information regarding AEP.

PART I

ITEM 1. BUSINESS

GENERAL

Overview and Description of Major Subsidiaries

AEP was incorporated under the laws of the State of New York in 1906 and reorganized in 1925. It is a public utility holding company that directly owns all of the outstanding common stock of the public utility subsidiaries identified below.

The service areas of AEP's public utility subsidiaries cover portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. Transmission networks are interconnected with extensive distribution facilities in the territories served. The public utility subsidiaries of AEP have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. Restructuring laws in Michigan, Ohio and the ERCOT area of Texas have caused AEP public utility subsidiaries in those states to unbundle previously integrated regulated rates for their retail customers.

The member companies of AEP have contractual, financial and other business relationships with the other member companies, such as participation in AEP savings and retirement plans and tax returns, sales of electricity and transportation and handling of fuel. The member companies of AEP also obtain certain accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost from a common provider, AEPSC.

As of December 31, 2025, the subsidiaries of AEP had a total of 17,581 employees. As a holding company rather than an operating company, AEP has no employees.

Summary information related to AEP subsidiary operating companies as of December 31, 2025 is shown in the table below:

	AEP Texas	AEPTCo	APCo	I&M	KGPCo (a)	KPCo	OPCo (b)	PSO	SWEPCo	WPCo
State of Incorporation	Delaware, 1925	Delaware, 2006	Virginia, 1926	Indiana, 1907	Virginia, 1917	Kentucky, 1919	Ohio, 1907	Oklahoma, 1913	Delaware, 1912	West Virginia, 1883
AEP Reportable Segment	T&D	AEPTHCo	VIU	VIU	VIU	VIU	T&D	VIU	VIU	VIU
RTO Affiliation	ERCOT	(c)	PJM	PJM	PJM	PJM	PJM	SPP	SPP	PJM
Approximate Number of Retail Customers	1,133,000	(c)	971,000	621,000	50,000	161,000	1,547,000	588,000	558,000	41,000
Number of Employees	1,730	(c)	1,682	2,152	48	304	1,556	1,150	1,392	229

(a) KGPCo does not own any generating facilities and purchases electric power from APCo for distribution to its customers.

(b) OPCo purchases energy and capacity at auction to serve generation service customers who have not switched to a competitive generation supplier.

(c) AEPTCo is a holding company for the State Transcos, other than IMTCo and OHTCo, and Midwest Transmission Holdings. Five State Transcos are members of PJM and two State Transcos are members of SPP. Neither AEPTCo nor its subsidiaries have any employees. Instead, AEPSC and certain AEP utility subsidiaries provide services to these entities.

Service Company Subsidiary

AEPSC is a service company subsidiary that provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to AEP subsidiaries. The executive officers of AEP and certain of the executive officers of its public utility subsidiaries are employees of AEPSC. As of December 31, 2025, AEPSC had 6,994 employees.

Principal Industries Served

The following table illustrates the principal industries and wholesale electric markets served by AEP's public utility subsidiaries.

	AEP Texas	APCo	I&M	KGPCo	KPCo	OPCo	PSO	SWEPCo	WPCo
Principal Industries Served:									
Petroleum and Coal Products Manufacturing	X				X	X	X		
Chemical Manufacturing	X	X	X	X	X	X		X	X
Oil and Gas Extraction	X				X		X	X	
Pipeline Transportation	X	X			X	X		X	X
Primary Metal Manufacturing	X	X	X			X		X	X
Data Processing (a)	X		X			X			
Coal-Mining		X			X				X
Paper Manufacturing				X			X	X	
Transportation Equipment		X	X						
Plastics and Rubber Products			X	X			X		X
Fabricated Metals Product Manufacturing			X			X			
Food Manufacturing				X			X	X	
Supply and Market Electric Power at Wholesale to:									
Other Electric Utility Companies		X	X		X		X	X	X
Rural Electric Cooperatives		X	X					X	
Municipalities		X	X		X		X	X	
Other Market Participants		X	X		X		X	X	X

(a) Primarily includes data centers and cryptocurrency operations.

Public Utility Subsidiaries by Jurisdiction

The following table illustrates certain regulatory information with respect to the jurisdictions in which the public utility subsidiaries of AEP operate:

Principal Jurisdiction	AEP Utility Subsidiaries Operating in that Jurisdiction	Authorized Return on Equity (a)
Arkansas	SWEPCo	9.65 % (b)
FERC	AEPTCo - APTCo, IMTCo, KTCo, WVTCo	10.35 %
FERC	AEPTCo - OHTCo	9.85 %
FERC	AEPTCo - OKTCo and SWTCo	10.50 %
Indiana	I&M	9.85 %
Kentucky	KPCo	9.75 %
Louisiana	SWEPCo	9.50 %
Michigan	I&M	9.86 %
Ohio	OPCo	9.70 %
Oklahoma	PSO	9.50 %
Tennessee	KGPCo	9.50 %
Texas	AEP Texas	9.76 %
Texas	SWEPCo	9.25 %
Virginia	APCo	9.75 %
West Virginia	APCo	9.25 %
West Virginia	WPCo	9.25 %

(a) Identifies the predominant current authorized ROE, and may not include other, less significant, permitted recovery. Actual ROE varies from authorized ROE.

(b) The APSC issued an order approving a 9.65% ROE effective February 2026. See "2025 Arkansas Base Rate Case" section of Note 4 for additional information.

CLASSES OF SERVICE

AEP and subsidiaries recognize revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. AEP's subsidiaries within the Vertically Integrated Utilities, Transmission and Distribution Utilities, AEP Transmission Holdco and Generation & Marketing segments derive revenue from the following sources: Retail Revenues, Wholesale and Competitive Retail Revenues, Other Revenues from Contracts with Customers and Alternative Revenues. For further information relating to the sources of revenue for the Registrants, see Note 20 - Revenues from Contracts with Customers for additional information.

FINANCING

General

AEP subsidiaries generally use short-term debt to finance working capital needs. Short-term debt may also be used to finance acquisitions, construction and redemption or repurchase of outstanding securities until such needs can be financed with long-term funding. In recent history, short-term funding needs have been provided for by cash from operations, AEP's commercial paper program and term loan issuances. Funds are made available to subsidiaries under the AEP corporate borrowing program. Certain public utility subsidiaries of AEP also sell accounts receivable to provide liquidity. Sources of long-term funding include issuance of long-term debt, long-term asset securitizations, leasing agreements, hybrid securities or common stock. See "Financial Condition" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

AEP's revolving credit agreements (which backstop the commercial paper program) include covenants and events of default typical for these types of facilities, including a maximum debt-to-total capitalization test. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of its 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 the credit agreements. As of December 31, 2025, AEP was in compliance with its debt covenants. With the exception of a voluntary bankruptcy or insolvency, any event of default has either or both a cure period or notice requirement before termination of the applicable agreement. A voluntary bankruptcy or insolvency of AEP or one of its significant subsidiaries would be considered an immediate termination event. See "Financial Condition" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

ENVIRONMENTAL AND OTHER MATTERS

AEP subsidiaries are currently subject to regulation by federal, state and local authorities with regard to air and water-quality control, solid and hazardous waste disposal and other environmental matters, and are subject to zoning and other regulation by local authorities. Current and proposed environmental laws and regulations will have an impact on AEP's operations. Management continues to monitor developments in the regulations and evaluate the economic feasibility and refine cost estimates for compliance. AEP is unable to predict how future changes in regulations, regulatory guidance, legal interpretations, policy positions and implementation actions will impact AEP's operations. For additional information on these laws and regulations, see "Environmental Issues" section of Management's Discussion and Analysis of Financial Condition and Results of Operations.

HUMAN CAPITAL MANAGEMENT

Attracting, developing and retaining high-performing employees with the skills and experience needed to serve customers efficiently and effectively is crucial to AEP's growth and competitiveness and is central to the Company's long-term strategy. AEP invests in employees and continues to build a high performance and inclusive culture that inspires leadership, encourages innovative thinking and welcomes everyone.

The following table shows AEP's number of employees by subsidiary as of December 31, 2025:

Subsidiary	Number of Employees
AEPSC	6,994
AEP Texas	1,730
APCo	1,682
I&M	2,152
KGPCo	48
KPCo	304
OPCo	1,556
PSO	1,150
SWEPCo	1,392
WPCo	229
Other (a)	344
Total AEP (b)	17,581

(a) Primarily relates to AEP Energy employees.
(b) Approximately 24% of AEP's total workforce was represented by labor unions.

Safety

Safety is integral to culture and is one of AEP's core values. AEP is dedicated to the safety of employees, contractors, customers and the communities AEP serves. AEP has policies, procedures, programs, training and initiatives in place to help provide a safety conscious work environment. AEP is committed to fundamentally embedding layers of protection in its operations. This includes focusing efforts to prevent serious injuries and fatalities, strengthening pre-job briefing effectiveness, learning from safety incidents, providing appropriate training and education and improving proactive safety initiatives and data analysis to identify and address potential performance gaps.

In 2025, the company experienced a workplace fatality involving one employee. AEP learned from this event and has taken action to better protect employees and all those who support AEP.

Safety Metric	2025	2024
DART	0.436	0.556
TRIR	0.755	0.913

AEP's employee Days Away, Restricted and Transferred (DART) rate and Total Recordable Incident Rate (TRIR) improved in 2025. A DART event is a work-related incident that results in one or more restricted work days or an employee transferring to a different job within the company. The DART rate is the number of DART events multiplied by 200,000 and divided by total hours worked, normalizing the results to injuries per 100 full-time equivalent employees annually. A recordable event is a work-related event that results in death, days away from work, restricted work or transfer to another job, medical treatment beyond first aid, loss of consciousness or a significant injury or illness diagnosed by a physician or other licensed health care professional. TRIR shows how often these recordable injuries happen. It is a mathematical calculation (number of recordable events multiplied by 200,000 and divided by total hours worked) expressing the number of recordable incidents per 100 full-time employees annually. AEP has made progress reducing injury rates and is reaffirming its commitment to continuous improvement in safety and health to provide a safer work environment for all.

Culture

AEP aims to foster a culture of belonging, where every employee can thrive and contribute their best to support AEP's mission, vision and core principles. AEP recognizes that an engaged, collaborative and innovative workforce helps better serve employees, customers, suppliers and other key stakeholders. AEP is focused on building a performance-based and accountable culture to effectively support its operating companies and enhance customer service. AEP's culture progress is measured in part through the annual Employee Voice Survey. The Employee Voice Survey is an opportunity for employees to provide feedback about their experience at AEP. It also serves as a means for the Company to understand how to foster a workplace

focused on performance, accountability, collaboration and customer orientation. 2025 marks AEP's twelfth consecutive year of formally surveying employees about their experience.

Training and Professional Development

Attracting, developing, and retaining high-performing employees with the skills and experience needed to serve customers efficiently and effectively is crucial to AEP's growth and long-term strategy. AEP is preparing its workforce for the future by providing opportunities to learn new skills and engaging higher education institutions to better prepare the next generation of workers. AEP offers co-op and internship programs in partnership with high schools, technical/vocational schools and colleges across AEP's 11-state service territory. AEP also provides a broad range of training and assistance that supports lifelong learning and development. This includes operational skills training, professional training, leadership development, educational assistance, ongoing performance coaching and other forms of development that offer career pathways for employees.

Compensation and Benefits

AEP is committed to the well-being of employees, and offers programs to foster employee financial well-being, physical and emotional health, and social connectedness. AEP provides market-competitive compensation and benefits, including medical and dental coverage, life insurance, and well-being programs designed to support employees and their families. Eligible AEP employees participate in an annual incentive program that rewards individual performance and achievement of business goals, fostering a high-performance culture. AEP also offers paid time off in the form of vacation, holidays, sick time and parental leave.

BUSINESS SEGMENTS

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.

Seasonality

The consumption and delivery of electric power is generally seasonal which impacts the results of operations of AEP's reportable segments. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In some areas, power demand peaks during the cold winter months. The pattern of this fluctuation may change due to the nature and location of AEP's facilities and the terms of power sale contracts into which AEP enters. In addition, AEP has historically sold and delivered less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish AEP's results of operations. Conversely, unusually extreme weather temperatures could increase AEP's results of operations.

VERTICALLY INTEGRATED UTILITIES

GENERAL

The Vertically Integrated Utilities operations are engaged in the 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. AEPSC, as agent for AEP's public utility subsidiaries, performs marketing, generation dispatch, fuel procurement and power-related risk management and trading activities on behalf of each of these subsidiaries.

ELECTRIC GENERATION

Facilities

As of December 31, 2025, the Vertically Integrated Utilities owned approximately 25,400 MWs of generation. See Item 2 – Properties for more information regarding the generation capacity of vertically integrated public utility subsidiaries.

Fuel Supply

The following table shows the owned and leased generation sources by type (including wind purchase agreements), on an actual net generation (MWhs) basis, used by the Vertically Integrated Utilities:

	2025	2024	2023
Coal and Lignite	43%	40%	37%
Nuclear	19%	22%	22%
Natural Gas	22%	22%	22%
Renewables	16%	16%	19%

An increase/decrease in one or more generation types relative to previous years reflects changes in resource mix and price changes in one or more fuel commodity sources relative to the pricing of other fuel commodity sources. AEP's overall 2025

fossil fuel costs for the Vertically Integrated Utilities increased 0.5% on a dollar per MMBtu basis from 2024. AEP's resource mix is driven by the needs and desires of the states AEP serves and continued focus on cost effective economic dispatch to AEP's customers.

Coal and Lignite

The Vertically Integrated Utilities procure coal under a combination of purchasing arrangements, including long-term contracts and spot agreements with various producers and marketers.

Management has coal contracts in place with suppliers through 2031 for a portion of the Company's projected coal requirements. As of December 31, 2025, through subsidiaries, the Vertically Integrated Utilities own, lease or control 3,009 railcars, 270 barges, 4 towboats and a coal handling terminal with approximately 18 million tons of annual capacity to move and store coal for use in AEP generating facilities. The Vertically Integrated Utilities will secure additional railcar and barge/towboat capacity as needed to support demand.

The Vertically Integrated Utilities' strategy for purchasing coal includes maintaining a target inventory level by layering in supplies over time to help with reducing price volatility. The price paid for coal delivered in 2025 decreased approximately 11.6% from 2024 mainly due to the completion of higher priced coal supply agreements that were agreed to in 2021 and 2022 when coal market pricing was stronger. The Vertically Integrated Utilities' coal costs are typically recovered through various fuel reconciliation mechanisms.

The following table shows the amount of coal and lignite delivered to the Vertically Integrated Utilities' plants during the past three years and the average delivered price of coal and lignite purchased by the Vertically Integrated Utilities:

	2025	2024	2023 (a)
Total coal and lignite delivered to the plants (in millions of tons)	19	17	21
Average cost per ton of coal and lignite delivered	$ 54.86	$ 62.05	$ 64.31

(a) Deliveries of lignite ended after the first quarter of 2023.

The coal inventories at the Vertically Integrated Utilities' plants fluctuate based on several factors, including consumption rates driven by electric power demand, unit outages, transportation constraints or delays, on-site space limitations, labor issues, supplier outages or performance issues and weather conditions, all of which can affect production, consumption or deliveries. As of December 31, 2025, the Vertically Integrated Utilities' coal inventory was approximately 63 days of full load burn, down from the elevated levels experienced in recent years, but still above AEP's targeted inventory level. While inventory targets vary by plant and are adjusted as necessary, the current inventory target is approximately 35 days of full load burn per plant for the Vertically Integrated Utilities. Inventory levels are expected to continue to decline in 2026 but will likely still not reach the inventory target levels by year-end.

Natural Gas

The Vertically Integrated Utilities consumed approximately 164 billion cubic feet of natural gas during 2025 for generating power, which represents an increase of 5.8% from 2024. While nominal year-over-year natural gas consumption increases were experienced across AEP's operating companies, the main consumption increase driver was related to the Green Country Power Plant, which was acquired by PSO on June 30, 2025. From a delivered natural gas cost perspective, total costs increased 21.6% from 2024.

Several natural gas-fired units are connected to at least two pipelines, which allows greater access to competitive supplies and improves delivery reliability. From a natural gas supply perspective, the Vertically Integrated Utilities secure forward month, fixed price baseload supply, prompt month baseload supply, and pursue daily spot market purchases or sales (to balance daily positions). From a natural gas transportation perspective, the Vertically Integrated Utilities utilize firm and interruptible transportation capacity. Furthermore, SWEPCo and PSO utilize firm natural gas storage, which supports price stability and provides additional surety of natural gas supply. AEP's natural gas supply, transportation and storage transactions are competitively bid and are based on applicable market prices.

The Vertically Integrated Utilities' natural gas supply, transportation and storage costs are typically recovered through various fuel reconciliation mechanisms.

The following table shows the amount of natural gas delivered to the Vertically Integrated Utilities' plants during the past three years and the average delivered price of natural gas purchased by the Vertically Integrated Utilities:

	2025	2024	2023
Total natural gas delivered to the plants (in billions of cubic feet)	164	155	146
Average delivered price per MMBtu of purchased natural gas	$ 3.71	$ 3.05	$ 2.69

Nuclear

I&M has made commitments to meet the current nuclear fuel requirements of the Cook Plant. I&M has made and will make purchases of uranium in various forms in the spot, short-term, mid-term and long-term markets.

For purposes of the storage of high-level radioactive waste in the form of SNF, I&M completed modifications to its SNF storage pool in the early 1990's. I&M entered into an agreement to provide for onsite dry cask storage of SNF to permit normal operations to continue. I&M is scheduled to conduct further dry cask loading and storage projects on an ongoing periodic basis. The year of expiration of each NRC Operating License is 2034 for Unit 1 and 2037 for Unit 2. 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.

Nuclear Waste and Decommissioning

As the owner of the Cook Plant, I&M has a significant future financial obligation to dispose of SNF and decommission and decontaminate the plant safely. NRC regulations and the SNF disposal program impact the cost to decommission the Cook Plant. The most recent decommissioning cost study was completed 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. As of December 31, 2025 and 2024, the total decommissioning trust fund balance for the Cook Plant was approximately $4.5 billion and $4 billion, respectively. The balance of funds available to eventually decommission Cook Plant will differ based on contributions and investment returns. The ultimate cost of retiring the Cook Plant may be materially different from estimates and funding targets as a result of the:

- Escalation of various cost elements (including, but not limited to, general inflation and the cost of energy).
- Further development of regulatory requirements governing decommissioning.
- Technology available at the time of decommissioning differing significantly from that assumed in studies.
- Availability of nuclear waste disposal facilities.
- Availability of a United States Department of Energy facility for permanent storage of SNF.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant will not be significantly different than current projections. AEP will seek recovery from customers through regulated rates if actual decommissioning costs exceed projections. See the "Nuclear Contingencies" section of Note 6 - Commitments, Guarantees and Contingencies for additional information with respect to nuclear waste and decommissioning.

Low-Level Radioactive Waste

The Low-Level Waste Policy Act of 1980 mandates that the responsibility for the disposal of low-level radioactive waste rests with the individual states. Low-level radioactive waste consists largely of ordinary refuse and other items that have come in contact with radioactive materials. Michigan does not currently have a disposal site for such waste available. I&M cannot predict when such a site may be available. However, the states of Utah and Texas have licensed low-level radioactive waste disposal sites which currently accept low-level radioactive waste from Michigan waste generators, which I&M currently utilizes. There is currently no set date limiting I&M's access to either of these facilities. The Cook Plant has a facility onsite designed specifically for the storage of low-level radioactive waste. In the event that low-level radioactive waste disposal facility access becomes unavailable, it can be stored onsite at this facility.

Counterparty Risk Management

The Vertically Integrated Utilities segment also sells power and enters into related energy transactions with wholesale customers and other market participants. As a result, counterparties and exchanges may require cash or cash related instruments to be deposited on transactions as margin against open positions. As of December 31, 2025, counterparties posted

approximately $112 million in cash, cash equivalents or letters of credit with AEPSC for the benefit of AEP's public utility subsidiaries (while, as of that date, AEP's public utility subsidiaries posted approximately $214 million with counterparties and exchanges). Since open trading contracts are valued based on market prices of various commodities, exposures change daily. See the "Quantitative and Qualitative Disclosures About Market Risk" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

Certain Power Agreements

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 a demand charge for the right to receive such power (and 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).

OVEC

AEP and several nonaffiliated utility companies jointly own OVEC. The aggregate equity participation of AEP in OVEC is 43.47%. Parent owns 39.17% and OPCo owns 4.3%. Under the Inter-Company Power Agreement (ICPA), which defines the rights of the owners and sets the power participation ratio of each, the sponsoring companies are entitled to receive and are obligated to pay for all OVEC capacity (approximately 2,400 MWs) in proportion to their respective power participation ratios. The aggregate power participation ratio of APCo, I&M and OPCo is 43.47%. The ICPA terminates in June 2040. The proceeds from charges by OVEC to sponsoring companies under the ICPA based on their power participation ratios are designed to be sufficient for OVEC to meet its operating expenses and fixed costs. OVEC's Board of Directors, as elected by AEP and nonaffiliated owners, has authorized environmental investments related to their ownership interests, with resulting expenses (including for related debt and interest thereon) included in charges under the ICPA. 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 through debt issuances, including tax-advantaged debt issuances. Both OVEC generation plants are operating with environmental controls in-service. See Note 18 - Variable Interest Entities and Equity Method Investments for additional information.

ELECTRIC DELIVERY

General

Other than AEGCo, the Vertically Integrated Utilities own and operate transmission and distribution lines and other facilities to deliver electric power. See Item 2 – Properties for more information regarding the transmission and distribution lines. Most of the transmission and distribution services are sold to retail customers of the Vertically Integrated Utilities in their service territories. These sales are made at rates approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC. The FERC regulates and approves the rates for both wholesale transmission transactions and wholesale generation contracts. The use and the recovery of costs associated with the transmission assets of the Vertically Integrated Utilities are subject to the rules, principles, protocols and agreements in place with PJM and SPP, and as approved by the FERC. See Item 1. Business – Vertically Integrated Utilities – Regulation – FERC. As discussed below, some transmission services also are separately sold to nonaffiliated companies.

Other than AEGCo, the Vertically Integrated Utilities hold franchises or other rights to provide electric service in various municipalities and regions in their service areas. In some cases, these franchises provide the utility with the exclusive right to provide electric service within a specific territory. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business.

Transmission Agreement

APCo, I&M, KGPCo, KPCo and WPCo own and operate transmission facilities that are used to provide transmission service under the PJM OATT and are parties to the TA. OPCo, which is a subsidiary in AEP's Transmission and Distribution Utilities segment that provides transmission service under the PJM OATT, is also a party to the TA. The TA defines how the parties to

the agreement share the revenues associated with their transmission facilities and the costs of transmission service provided by PJM. The FERC has approved the TA.

Transmission Coordination Agreement and Open Access Transmission Tariff

PSO, SWEPCo and AEPSC are parties to the TCA. Under the TCA, a coordinating committee is charged with the responsibility of: (a) overseeing the coordinated planning of the transmission facilities of the parties to the agreement, including the performance of transmission planning studies, (b) the interaction of such subsidiaries with independent system operators and other regional bodies interested in transmission planning and (c) compliance with the terms of the AEP and SPP OATTs filed with the FERC and the rules of the FERC relating to such tariffs. Pursuant to the TCA, PSO, SWEPCo and AEPSC each have responsibility for monitoring and reporting situations or problems that materially affect the reliability of PSO's and SWEPCo's transmission systems. The TCA also provides for the allocation among the parties of revenues collected for transmission and ancillary services as determined by the FERC-approved OATT for SPP.

Regional Transmission Organizations

AEGCo, APCo, I&M, KGPCo, KPCo and WPCo are members of PJM, and PSO and SWEPCo are members of SPP (both FERC-approved RTOs). RTOs operate, plan and control utility transmission assets in a manner designed to provide open access to such assets in a way that prevents discrimination between participants owning transmission assets and those that do not.

REGULATION

General

The Vertically Integrated Utilities' retail rates and certain other matters are subject to traditional cost-based regulation by the state utility commissions. The Vertically Integrated Utilities are also subject to regulation by the FERC under the Federal Power Act with respect to wholesale power and transmission service transactions. I&M is subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant. AEP and its vertically integrated public utility subsidiaries are also subject to the regulatory provisions of much of the Energy Policy Act of 2005, which is administered by the FERC.

Rates

Historically, state utility commissions have established electric service rates on a cost-of-service basis, which is designed to allow a utility an opportunity to recover its cost of providing service and to earn a reasonable return on its investment used in providing that service. A utility's cost of service generally reflects its operating expenses, including operation and maintenance expense, depreciation expense and taxes. State utility commissions periodically adjust rates pursuant to a review of: (a) a utility's adjusted revenues and expenses during a defined test period and (b) such utility's level of investment. Absent a legal limitation, such as a law limiting the frequency of rate changes or capping rates for a period of time, a state utility commission can review and change rates on its own initiative. Some states may initiate reviews at the request of a utility, customer, governmental or other representative of a group of customers. Such parties may, however, agree with one another not to request reviews of or changes to rates for a specified period of time.

Public utilities have traditionally financed capital investments until the new asset is placed in-service. Provided the asset was found to be a prudent investment, it was then added to rate base and entitled to a return through rate recovery. Given long lead times in construction, the high costs of plant and equipment and volatile capital markets, management actively pursues strategies to accelerate rate recognition of investments and cash flow. AEP representatives continue to engage state commissioners and legislators on alternative ratemaking options to reduce regulatory lag and enhance certainty in the process. These options include pre-approvals, a return on construction work in progress, rider/trackers, formula rates and the inclusion of future test-year projections into rates.

The rates of the Vertically Integrated Utilities are generally based on the cost of providing traditional bundled electric service (i.e., generation, transmission and distribution service). Historically, the state regulatory frameworks in the service area of the Vertically Integrated Utilities reflected specified fuel costs as part of bundled (or, more recently, unbundled) rates or incorporated fuel adjustment clauses in a utility's rates and tariffs. Fuel adjustment clauses permit periodic adjustments to fuel cost recovery from customers and therefore provide protection against exposure to fuel cost changes.

The following state-by-state analysis summarizes the regulatory environment of jurisdictions in which AEP's vertically integrated public utility subsidiaries operate. Several public utility subsidiaries operate in more than one jurisdiction. See Note 4 - Rate Matters for more information regarding pending rate matters.

Arkansas

SWEPCo provides retail electric service in Arkansas at bundled rates approved by the APSC with rates set on a historical cost-of-service basis and formula rates. Arkansas provides for timely fuel and purchased power cost recovery through respective annual fuel and purchased power recovery mechanisms.

Indiana

I&M provides retail electric service in Indiana at fully bundled rates approved by the IURC with rates set on a forecasted cost-of-service basis. Indiana allows for timely recovery of fuel expenses through a fuel recovery surcharge mechanism and has approved additional recovery mechanisms associated with purchase power capacity, transmission and certain generation and environmental-related costs. I&M is subject to a semi-annual Indiana jurisdictional earnings test.

Kentucky

KPCo provides retail electric service in Kentucky at bundled rates approved by the KPSC with rates currently set on a historical cost-of-service basis. Kentucky generally allows for timely recovery of fuel expenses through a fuel recovery surcharge mechanism.

Louisiana

SWEPCo provides retail electric service in Louisiana at bundled rates approved by the LPSC with rates set on a historical cost-of-service basis and formula rates. Louisiana provides for timely fuel and purchased power cost recovery through respective fuel and purchased power recovery mechanisms updated monthly.

Michigan

I&M provides retail electric service in Michigan at both unbundled standard service and open access distribution service rates approved by the MPSC, with rates set on a forecasted cost-of-service basis. Open access distribution service is limited to 10% of I&M's retail load. Michigan generally allows for timely recovery of fuel expenses, transmission expenses and purchased power expenses through a single surcharge mechanism.

Oklahoma

PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC with rates set on a historical cost-of-service basis. Fuel and purchased energy costs are recovered through a fuel adjustment clause.

Tennessee

KGPCo currently provides retail electric service in Tennessee at bundled rates approved by the TPUC with rates set on a historical cost-of-service basis. Tennessee generally allows for timely recovery of fuel expenses and purchased power expenses through a surcharge mechanism.

Texas

SWEPCo provides retail electric service in Texas at bundled rates approved by the PUCT with rates set on a historical cost-of-service basis. Texas generally provides for timely fuel and purchased power cost recovery through respective fuel and purchased power recovery mechanisms.

Virginia

APCo currently provides retail electric service in Virginia at unbundled generation and distribution rates approved by the Virginia SCC with rates set on a historical cost-of-service basis. Virginia generally allows for timely recovery of fuel expenses through a fuel cost recovery surcharge mechanism. In addition to base rates and fuel cost recovery, APCo is permitted to

recover transmission expenses provided at OATT rates based on rates established by the FERC. APCo is subject to a biennial Virginia retail generation and distribution earnings test.

West Virginia

APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC with rates set on a combined APCo and WPCo historical cost-of-service basis. West Virginia generally allows for timely recovery of fuel expenses, purchased power expenses and transmission expenses through a single surcharge mechanism.

FERC

The FERC regulates rates for interstate power sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. The FERC regulations require the Vertically Integrated Utilities to provide open access transmission service at FERC-approved rates, and AEP has approved cost-based formula transmission rates on file at the FERC. The FERC also regulates unbundled transmission service to retail customers. In addition, the FERC regulates the sale of power for resale in interstate commerce by: (a) approving contracts for wholesale sales to municipal and cooperative utilities at cost-based rates and (b) granting authority to public utilities to sell power at wholesale at market-based rates upon a showing that the seller lacks the ability to improperly influence market prices. AEP's vertically integrated public utility subsidiaries have market-based rate authority from the FERC, under which much of their wholesale marketing activity takes place. The FERC requires each public utility that owns or controls interstate transmission facilities, directly or through an RTO, to file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The FERC also requires all transmitting utilities, directly or through an RTO, to establish an Open Access Same-time Information System, which electronically posts transmission information such as available capacity and prices, and requires utilities to comply with Standards of Conduct that prohibit utilities' transmission employees from providing non-public transmission information to the utility's marketing employees. Additionally, the vertically integrated public utility subsidiaries are subject to mandatory reliability standards promulgated by the NERC, with the approval of the FERC, which standards protect the nation's bulk power system against potential disruptions from cyber and physical security breaches.

The FERC oversees RTOs, entities created to operate, plan and control utility transmission assets. AEGCo, APCo, I&M, KGPCo, KPCo and WPCo are members of PJM. PSO and SWEPCo are members of SPP.

The FERC has jurisdiction over certain issuances of securities of most of AEP's public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. In addition, both the FERC and state regulators are permitted to review the books and records of any company within a holding company system.

COMPETITION

The Vertically Integrated Utilities primarily generate, transmit and distribute electricity to their retail customers in their service territories. These sales are made at rates approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC, and are not subject to competition from other vertically integrated public utilities. Other than AEGCo, the Vertically Integrated Utilities hold franchises or other rights that effectively grant the exclusive ability to provide electric service in various municipalities and regions in their service areas.

The Vertically Integrated Utilities compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil, renewables and coal, within their service areas. The primary factors in such competition are price, reliability of service and the capability of customers to utilize alternative sources of energy other than electric power. With respect to competing generators and self-generation, the public utility subsidiaries of AEP believe that they currently maintain a competitive position.

TRANSMISSION AND DISTRIBUTION UTILITIES

GENERAL

This segment consists of the transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEP Texas and OPCo.

The Transmission and Distribution Utilities own and operate transmission and distribution lines and other facilities to deliver electric power. See Item 2 – Properties, for more information regarding the transmission and distribution lines. Transmission and distribution services are sold to their retail customers in their service territories. These sales are made at rates approved by the PUCT for AEP Texas and by the PUCO and the FERC for OPCo. The FERC regulates and approves the rates for wholesale transmission transactions. As discussed below, some transmission services also are separately sold to nonaffiliated companies.

The Transmission and Distribution Utilities hold franchises or other rights to provide electric service in various municipalities and regions in their service areas. In some cases, these franchises provide the utility with the exclusive right to provide electric service. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business.

The use and the recovery of costs associated with the transmission assets of the Transmission and Distribution Utilities are subject to the rules, protocols and agreements in place with PJM and ERCOT, and as approved by the FERC. In addition to providing transmission services in connection with power sales in their service areas, AEP's transmission and distribution utility subsidiaries also provide transmission services for nonaffiliated companies through RTOs.

Transmission Agreement

OPCo owns and operates transmission facilities that are used to provide transmission service under the PJM OATT; OPCo is a party to the TA with other utility subsidiary affiliates. The TA defines how the parties to the agreement share the revenues associated with their transmission facilities and the costs of transmission service provided by PJM. The FERC has approved the TA.

Regional Transmission Organizations

OPCo is a member of PJM, a FERC-approved RTO. RTOs operate, plan and control utility transmission assets to provide open access to such assets in a way that prevents discrimination between participants owning transmission assets and those that do not. AEP Texas is a member of ERCOT.

REGULATION

Transmission and distribution rates are established on a cost-of-service basis, which is designed to allow a utility company an opportunity to recover its cost of providing service and to earn a reasonable return on its investment used in providing that service. The cost-of-service generally reflects operating expenses, including operation and maintenance expense, depreciation expense and taxes. Utility commissions periodically adjust rates pursuant to a review of: (a) a utility's adjusted revenues and expenses during a defined test period and (b) such utility's level of investment.

OPCo provides transmission and distribution services to retail customers within its service territory at cost-based rates approved by the PUCO or by the FERC. AEP Texas provides transmission and distribution services to REPs within its service territory. Prior to the passage of Texas House Bill 5247 (HB 5247) in June 2025, AEP Texas set rates through a combination of base rate cases and interim Transmission Cost of Services (TCOS) and Distribution Cost Recovery Factor (DCRF) semi-annual filings which update rates to reflect changes in net invested capital. In October 2025, AEP Texas submitted its first annual interim rate adjustment filing with the PUCT seeking recovery of eligible costs through the UTM established by HB 5247. This filing combined three recovery mechanisms (TCOS, DCRF and Transmission Cost Recovery Factor (TCRF)) into a single filing. AEP Texas and OPCo also have PUCT and PUCO, respectively, approved rider/tracker mechanisms which are periodically reset and designed to recover certain operating expenses.

FERC

The FERC regulates rates for transmission of electric power, accounting and other matters. The FERC regulations require AEP to provide open access transmission service at FERC-approved rates, and it has approved cost-based formula transmission rates on file at the FERC. The FERC also regulates unbundled transmission service to retail customers. The FERC requires each public utility that owns or controls interstate transmission facilities to, directly or through an RTO, file an open access network

and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The FERC also requires all transmitting utilities, directly or through an RTO, to establish an Open Access Same-time Information System, which electronically posts transmission information such as available capacity and prices, and requires utilities to comply with Standards of Conduct that prohibit utilities' transmission employees from providing non-public transmission information to the utility's marketing employees. In addition, both the FERC and state regulators are permitted to review the books and records of any company within a holding company system. Additionally, the transmission and distribution utility subsidiaries are subject to mandatory reliability standards as set forth by the NERC, with the approval of the FERC, which standards protect the nation's bulk power system against potential disruptions from cyber and physical security breaches.

AEP TRANSMISSION HOLDCO

GENERAL

AEPTHCo is a holding company for AEPTCo. AEPTHCo also has interests in several AEP Transmission Joint Ventures. AEPTCo is the direct holding company of APTCo, KTCo, OKTCo, SWTCo and WVTCo. AEPTCo also has a controlling interest in Midwest Transmission Holdings. Midwest Transmission Holdings owns all of the issued and outstanding stock of IMTCo and OHTCo.

AEPTCo

The State Transcos are independent of, but respectively overlay, the following AEP electric utility operating companies: APCo, I&M, KPCo, OPCo, PSO, SWEPCo and WPCo. The State Transcos develop, own, operate and maintain their respective transmission assets. Individual State Transcos (a) have obtained the approvals necessary to operate in Indiana, Kentucky, Michigan, Ohio, Oklahoma and West Virginia, subject to any applicable siting requirements, (b) are authorized to submit projects for commission approval in Virginia and (c) have been granted consent to enter into a joint license agreement that will support investment in Tennessee. Assets of the State Transcos interconnect to transmission facilities owned by the aforementioned operating companies and nonaffiliated transmission owners within the footprints of PJM, MISO and SPP. APTCo, IMTCo, KTCo, OHTCo and WVTCo are located within PJM. IMTCo also owns portions of the Greentown station assets located in MISO. OKTCo and SWTCo are located within SPP. SWTCo does not currently own or operate transmission assets.

The State Transcos own, operate, maintain and invest in transmission infrastructure in order to maintain and enhance system integrity and grid reliability, grid security, safety, reduce transmission constraints and facilitate interconnections of new generating resources and new wholesale customers, as well as enhance competitive wholesale electricity markets. A key part of AEP's business is replacing and upgrading transmission facilities, assets and components of the existing AEP System as needed to maintain reliability. As of December 31, 2025, the State Transcos had $17.1 billion of transmission and other assets in-service, excluding CWIP, with plans to construct approximately $11.6 billion of additional transmission assets through 2030.

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.

AEPTHCO JOINT VENTURE INITIATIVES

AEPTHCo has established joint ventures with nonaffiliated electric utility companies for the purpose of developing, building and owning transmission assets that seek to improve reliability and market efficiency and provide transmission access to remote generation sources in North America (Transmission Joint Ventures). The Transmission Joint Ventures currently include:

Joint Venture Name	Location(s)	Projected or Actual Completion Date	AEPTHCo Ownership %	In-Service Net PP&E as of 12/31/2025	Approved Return on Equity
				(in millions)	
ETT	Texas (ERCOT)	(a)	50%	$ 3,744	9.6 %
Midcontinent Grid Solutions, LLC	Wisconsin	2034	50%	(b)	10.5 %
Prairie Wind Transmission, LLC	Kansas	2014	25%	121	12.8 %
Pioneer Transmission, LLC	Indiana	2018	50%	177	10.5 %
Transource Energy, LLC	Missouri, West Virginia, Maryland, Oklahoma and Pennsylvania	(c)	86.5%	496	10.3% - 11.3%
Valley Link Transmission Company, LLC	Maryland, Virginia and West Virginia	2029	31.1%	(d)	11.4 % (e)

(a) ETT is undertaking multiple projects and the completion dates will vary for those projects. ETT's investment in completed and active projects in ERCOT is expected to be $5.6 billion by 2030. Future projects will be evaluated on a case-by-case basis.
(b) The projects awarded by MISO are estimated to cost approximately $1.2 billion.
(c) Transource Energy, LLC is undertaking multiple projects and the completion dates will vary for those projects. Transource Energy, LLC's investment in current and active projects is expected to be $1.1 billion upon completion. Future projects will be evaluated on a case-by-case basis.
(d) The projects awarded by PJM are estimated to cost approximately $3.0 billion. Future projects will be evaluated on a case-by-case basis.
(e) Valley Link's base ROE is subject to ongoing settlement and hearing procedures.

Transource Energy LLC, and its subsidiaries Transource Missouri, Transource West Virginia, Transource Maryland, Transource Pennsylvania and Transource Oklahoma are consolidated joint ventures by AEP. All other joint ventures in the table above are not consolidated by AEP. AEP's joint ventures do not have employees. Business services for the joint ventures are provided by AEPSC and other AEP subsidiaries and the joint venture partners.

REGULATION

The State Transcos and the Transmission Joint Ventures located outside of ERCOT establish transmission rates annually through forward-looking formula rate filings with the FERC pursuant to FERC-approved implementation protocols. The protocols include a transparent, formal review process to verify the updated transmission rates are prudently-incurred and reasonably calculated.

The State Transcos' and the Transmission Joint Ventures' (where applicable) rates are included in the respective OATT for PJM and SPP. An OATT is the FERC rate schedule that provides the terms and conditions for transmission and related services on a transmission provider's transmission system. The FERC requires transmission providers such as PJM and SPP to offer transmission service to all eligible customers (for example, load-serving entities, power marketers, generators and customers) on a non-discriminatory basis.

The FERC-approved formula rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners in annual rate base filings with the FERC. The formula rates establish rates for a one-year period based on the current projects in-service and proposed projects for a defined timeframe. The formula rates also include a true-up calculation for the previous year's billings, allowing for over/under-recovery of the transmission owner's ATRR. PJM and SPP pay the transmission owners their ATRR for use of their facilities and bill transmission customers taking service under the PJM and SPP OATTs, based on the terms and conditions in the respective OATT for the service taken. Additionally, the State Transcos are subject to mandatory reliability standards promulgated by the NERC, with the approval of the FERC, which standards protect the nation's bulk power system against potential disruptions from cyber and physical security breaches. Management monitors pending matters before the FERC, including inquiries and challenges related to ROEs and transmission formula rates, that have the potential to reduce AEP's future transmission formula rates and/or the transmission ROE methodology.

In the annual formula rate filings described above, the State Transcos in aggregate filed formula rate base totals of $13.3 billion, $11.4 billion and $10.7 billion for 2025, 2024 and 2023, respectively. The total filed transmission revenue requirements, including prior year over/under-recovery of revenue and associated carrying charges were $2.1 billion, $1.9 billion and $1.8 billion for 2025, 2024 and 2023, respectively.

The rates of ETT, which is located in ERCOT, are determined by the PUCT through a combination of base rate cases and interim Transmission Cost of Services (TCOS) filings. ETT may file interim TCOS filings semi-annually to update its rates to reflect changes in its net invested capital.

GENERATION & MARKETING

GENERAL

Generation & Marketing focuses primarily on a retail supply business and a wholesale energy trading and marketing business which includes executing transactions and negotiating contracts to maximize value and mitigate pricing and delivery risk in response to evolving customer needs and market conditions. The segment also includes rights to Cardinal Plant Unit 1's power and capacity through 2028 pursuant to a PPA with a nonaffiliated electric cooperative. Generation & Marketing previously included AEP OnSite Partners prior to its sale in September 2024 and AEP Renewables prior to its sale in August 2023.

The retail energy supply business, AEP Energy, provides electricity and/or natural gas to residential, commercial and industrial customers in Illinois, Pennsylvania, Delaware, Maryland, New Jersey, Ohio and Washington, D.C. AEP Energy had approximately 922,342 customer accounts as of December 31, 2025.

The wholesale trading and marketing business transacts within RTOs to provide supply to customers, manage pricing risk or otherwise provide service to fulfill contractual obligations. Additionally in certain instances this business procures physical electricity from identified sources, including renewable generation, when providing service to customers.

COMPETITION

Generation & Marketing subsidiaries face competition for the sale of available power, capacity and ancillary services. The principal factors of impact are electricity and fuel prices, new market entrants, construction or retirement of generating assets by others and technological advances in power generation. Other factors impacting competitiveness include environmental regulation, transmission congestion or transportation constraints at or near generation facilities, inoperability or inefficiencies, outages and deactivations and retirements at generation facilities. Technology advancements, increased demand for clean energy, changing consumer behaviors, low-priced and abundant natural gas, and regulatory and public policy reforms are among the catalysts for transformation within the industry that impact competition for Generation & Marketing.

Generation & Marketing's retail energy supply business operates in jurisdictions that each establish laws and regulations governing its competitive market, and public utility commission communications and utility default service pricing can affect customer participation in retail competition. Severe load and market volatility, sustained low market volatility and maturing competitive environments can adversely affect this business.

Counterparty Risk Management

Counterparties and exchanges may require cash or cash related instruments to be deposited on these transactions as margin against open positions. As of December 31, 2025, counterparties posted approximately $146 million in cash, cash equivalents or letters of credit with AEP for the benefit of Generation & Marketing subsidiaries (while, as of that date, Generation & Marketing subsidiaries posted approximately $133 million with counterparties and exchanges). Since open trading contracts are valued based on market prices of various commodities, exposures change daily. See the "Quantitative and Qualitative Disclosures About Market Risk" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

The following persons are executive officers of AEP. Their ages are given as of February 12, 2026. The officers are appointed annually for a one-year term by the board of directors of AEP.

William J. Fehrman
Chair of the Board of Directors, President and Chief Executive Officer
Age 65
Chair of the Board of Directors since August 2025. President and Chief Executive Officer since August 2024. Director of the Board from August 2024 to August 2025. President and Chief Executive Officer of Centuri Holdings, Inc. from January 2024 to July 2024. President, Chief Executive Officer and Director of Berkshire Hathaway Energy Company from 2018 to 2023.

Rob Berntsen
Executive Vice President, General Counsel and Secretary
Age 56
Executive Vice President and General Counsel since July 2025. Executive Vice President and Chief Legal and Compliance Officer at Xcel Energy from May 2024 to June 2025. Senior Vice President, Chief of Staff and General Counsel of BHE Renewables from May 2022 to May 2024. Senior Vice President and General Counsel of BHE Infrastructure Group from December 2020 to May 2022.

Doug Cannon
President - AEP Transmission
Age 49
President - AEP Transmission since June 2025. Chief Executive Officer of NV Energy from January 2019 to May 2025. President of NV Energy from February 2018 to May 2025.

Johannes Eckert
Executive Vice President and Chief Information & Technology Officer
Age 58
Executive Vice President and Chief Information & Technology Officer since July 2025. Senior Vice President and Chief Information & Technology Officer of Cox Communications from 2016 to 2025.

Kelly J. Ferneau
Executive Vice President and Chief Nuclear Officer
Age 57
Executive Vice President and Chief Nuclear Officer since November 2024. I&M Site Vice President - Donald C. Cook Plant from July 2022 to October 2024. I&M Plant Manager from 2018 to June 2022.

Alicia R. Knapp
President - Nuclear Development
Age 47
President - Nuclear Development since September 2025. President and CEO of BHE Renewables from December 2020 to September 2025.

Trevor I. Mihalik
Executive Vice President and Chief Financial Officer
Age 59
Executive Vice President and Chief Financial Officer since January 2025. Executive Vice President and Group President of Sempra from January 2024 to January 2025. Executive Vice President and Chief Financial Officer of Sempra from 2018 to 2023.

Phillip R. Ulrich
Executive Vice President and Chief Human Resources Officer
Age 54
Executive Vice President since January 2023. Chief Human Resources Officer since August 2021. Senior Vice President from August 2021 to December 2022. Chief Human Resources Officer of Flex, LTD from May 2019 to July 2021.

ITEM 1A. RISK FACTORS

GENERAL RISKS OF REGULATED OPERATIONS

AEP may not be able to recover the costs of substantial planned investment in capital improvements and additions. (Applies to all Registrants)

AEP's business and capital investment plans call for extensive investment in capital improvements and additions, including the construction or acquisition of additional transmission and generation facilities, installation and interconnection with data centers, modernizing existing infrastructure, installation of environmental upgrades and retrofits as well as other initiatives. AEP's public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates charged, affected AEP subsidiaries would not be able to recover the costs associated with their investments. This would cause financial results to be diminished.

The business and capital investment plans of AEP depend, in part, on the continued growth and viability of data centers and large load customers interconnecting with the AEP System. (Applies to all Registrants)

AEP is experiencing current and projected load demands that exceed historical experience, creating a business need for new power generating resources and transmission facilities. Much of this demand is driven by interconnecting with and providing power to data centers and other large load customers to serve an increasingly digital economy and to support AI. The business and capital investment plans of AEP are focused on meeting these current and projected needs. If these increased demands for electricity do not occur as projected or are not sustained as projected, for any reason, it could affect AEP's financial condition.

The business and capital investment plans of AEP are subject to execution risks. (Applies to all Registrants)

AEP's business and capital investment plans for the construction of new projects, including providing service to new data centers and other large load customers, involve execution risks that could adversely affect AEP's financial performance and/or impair AEP's ability to execute on these plans. These risks include delays, supply chain disruption and the unavailability of materials, cost overruns, inflation, the cost and availability of capital, labor disputes or shortages and other factors that could cause the total cost and timing of any project to exceed estimates. While AEP utilizes measures to limit the impact of these events, if any of these projects are canceled for any reason, including shifts in large customer needs, preferences or financial stability, shifts in demand for large customer products or services, changes in technology, failure to receive necessary regulatory approvals, cost recovery and/or siting or environmental permits, mitigation efforts might not be sufficient and it could result in significant unrecoverable costs and the execution of AEP's business and capital investment plans would be negatively impacted. In addition, if any construction work or investments have been recorded as an asset, an impairment may need to be recorded in the event a project is canceled. This would cause financial results to be diminished.

Meeting the significant increase in electricity demand from new data centers and other large-load customers will require substantial investment in new generation and transmission facilities. These projects may require levels of capital that exceed historical utility financing needs, and the ability of the capital markets to supply sufficient funding for large-scale infrastructure expansion is uncertain. AEP's ability to undertake these capital-intensive projects depends in part on continued access to debt and equity markets. If capital markets experience reduced liquidity, constrained capacity for utility issuances, or diminished investor appetite for long-duration infrastructure investments, AEP may be unable to obtain the financing required to support these projects. Even if capital is available, it may only be obtainable at significantly higher cost due to market conditions or competition for capital among utilities and other sectors. Any inability to secure adequate financing could delay or prevent the construction of required facilities, impair AEP's ability to serve its customers, and adversely affect future net income, cash flows and financial condition.

Regulated electric revenues and earnings are dependent on federal and state regulations that may limit AEP's ability to recover costs and other amounts. (Applies to all Registrants)

The rates customers pay to AEP regulated utility businesses are subject to approval by the FERC and the respective state utility commissions of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. AEP cannot predict the ultimate outcomes of any actions by the FERC or the respective state commissions in establishing rates. The occurrence of any of the following could reduce future net income and cash flows and negatively impact financial condition:

- If regulated utility earnings exceed the return established by a relevant commission, that commission could reduce future rates;
- The overturning or reversal on appeal of previously authorized recovery; and

- Any legislation, regulatory action or litigation outcome that triggers a reversal of a regulatory asset or deferred cost or establishment of a regulatory liability.

The regulated utility businesses, and the energy industry as a whole have experienced a period of rising costs and investments and an upward trend in spending, especially with respect to infrastructure investments, which are likely to continue in the foreseeable future. The increase in spending could trigger increased regulatory scrutiny to authorizing cost recovery, especially in a rising cost environment, whether due to inflation, tariffs, high fuel prices or otherwise, and/or in periods of economic decline or hardship. The inability to obtain cost recovery would adversely affect AEP's business, financial position, results of operations and cash flows. See Note 4 - Rate Matters for additional information.

Regulated electric revenues and earnings are subject to prudency review. (Applies to all Registrants)

Regulators have initiated and may initiate additional proceedings to investigate the prudence of costs in the AEP regulated utility businesses. In these proceedings and in base rate proceedings regulators examine the reasonableness or prudence of operation and maintenance practices, the level of expenditures (including storm costs and costs associated with capital projects), the allowed rates of return and rate base, the proposed resource acquisitions and the previously incurred capital expenditures that the regulated utility businesses seek to keep or place in rates. Regulators may disallow costs found not to have been prudently incurred or found not to have been incurred in compliance with applicable tariffs, creating risk in the ultimate recovery of those costs. Disallowance of these costs would adversely affect AEP's business, financial position, results of operations and cash flows.

Regulatory bodies may not allow recovery of costs incurred on a timely basis. (Applies to all Registrants)

Regulatory proceedings relating to rates and other matters typically involve multiple parties seeking to limit or reduce rates. Traditional base rate proceedings generally have long timelines, are primarily based on historical costs and may or may not be limited in scope or duration by statute. The length of these base rate proceedings can cause the regulated utility businesses to experience regulatory lag in recovering costs and result in earning less than the allowed returns. Decisions are typically subject to appeal, further exacerbating the regulatory lag and leading to additional uncertainty associated with rate case proceedings.

AEP is subject to negative publicity. (Applies to all Registrants)

The AEP regulated utility businesses have large customer and stakeholder bases and, as a result, could be subject to public criticism or adverse publicity focused on issues including the operation and maintenance of their assets and infrastructure, their preparedness for major storms or other extreme weather events and/or the time it takes to restore service after such events, or the quality of their service or the reasonableness of the cost of their service. In addition, the public holds diverse and often conflicting views on the use of fossil fuels which can subject AEP to adverse publicity in connection with its use of fossil fuels. Criticism or adverse publicity of any nature could render legislatures and other governing bodies, public service commissions and other regulatory authorities, and government officials less likely to view AEP or the applicable regulated utility in a favorable light and could potentially negatively affect legislative or regulatory processes or outcomes, as well as lead to increased regulatory oversight, more stringent legislative or regulatory requirements, or other legislation or regulatory actions that adversely affect the regulated utility businesses.

AEP's transmission investment strategy and execution are dependent on federal and state regulatory policy and implementation by RTOs. (Applies to all Registrants)

A significant portion of AEP's earnings is derived from transmission investments and activities. FERC policy currently supports the expansion and updating of the transmission infrastructure within its jurisdiction. If the FERC were to adopt a different policy, if states were to limit or restrict such policies, or if transmission needs do not continue or develop as projected, AEP's strategy of investing in transmission could be impacted. Further, AEP's transmission strategy seeks to obtain authorization or to win bids to install, construct and operate new transmission lines and facilities. However, there can be no assurance that PJM, SPP, ERCOT or other RTOs will authorize new transmission projects or will award such projects to AEP.

Certain elements of AEP's transmission formula rates have been challenged, which could result in lowered rates and/or refunds of amounts previously collected. (Applies to all Registrants other than AEP Texas)

AEP provides transmission service under rates regulated by the FERC. The FERC approved the cost-based formula rate templates used by AEP to calculate its respective annual revenue requirements, but it has not expressly approved the amount of actual capital and operating expenditures to be used in the formula rates. All aspects of AEP's rates accepted or approved by the FERC, including the formula rate templates, the rates of return on the actual equity portion of its respective capital structures and the approved targeted capital structures, are subject to challenge by interested parties at the FERC, or by the

FERC on its own initiative. In addition, interested parties may challenge the annual implementation and calculation by AEP of its projected rates and formula rate true-up pursuant to its approved formula rate templates under AEP's formula rate implementation protocols. If a challenger can establish that any of these aspects are unjust, unreasonable, unduly discriminatory or preferential, then the FERC can make appropriate prospective adjustments to them and/or disallow any of AEP's inclusion of those aspects in the rate setting formula.

Inquiries related to rates of return, as well as challenges to the formula rates of other utilities, are ongoing in other proceedings at the FERC. The results of these proceedings could potentially negatively impact AEP in any future challenges to AEP's formula rates. If the FERC orders revenue reductions, including refunds, in any future cases related to its formula rates, it could reduce future net income and cash flows and impact financial condition.

End-use consumers and entities supplying electricity to end-use consumers may also attempt to influence government and/or regulators to change the rate setting methodologies that apply to AEP, particularly if rates for delivered electricity increase substantially.

AEP faces risks related to project siting, financing, construction, permitting, governmental approvals and the negotiation of project development agreements that may impede their development and operating activities. (Applies to all Registrants)

AEP owns, develops, constructs, manages and operates electric generation, transmission and distribution facilities. A key component of AEP's growth is its ability to construct and operate these facilities. As part of these operations AEP must periodically apply for licenses and permits from various local, state, federal and other regulatory authorities and abide by their respective conditions. Should AEP be unsuccessful in obtaining necessary licenses or permits on acceptable terms or resolving third-party challenges to such licenses or permits, should there be a delay in obtaining or renewing necessary licenses or permits or should regulatory authorities initiate any associated investigations or enforcement actions or impose related penalties or disallowances, it could reduce future net income and cash flows and impact financial condition. Any failure to timely construct contracted generation, transmission and distribution facilities or to negotiate successful project development agreements for new facilities with third-parties, including new data centers and large load customers, could impact future net income and cash flows and impact financial condition. Any failure to timely construct contracted generation, transmission and distribution facilities or to negotiate successful project development agreements for new facilities with third-parties, including new data centers and other large load customers, could impact future net income and cash flows and impact financial condition.

Changes in technology and regulatory policies may lower the value of electric utility facilities and franchises. (Applies to all Registrants)

AEP primarily generates electricity at large central facilities and delivers that electricity over its transmission and distribution facilities to customers usually situated within an exclusive franchise. This method results in economies of scale and generally lower costs than newer technologies, such as fuel cells and microturbines, and distributed generation using either new or existing technology. Other technologies, such as light emitting diodes (LEDs), increase the efficiency of electricity and, as a result, lower the demand for it. Changes in regulatory policies and advances in batteries or energy storage, wind turbines and photovoltaic solar cells are reducing costs of new technology to levels that are making them competitive with some central station electricity production and delivery. These developments can challenge AEP's competitive ability to maintain relatively low cost, efficient and reliable operations, to establish fair regulatory mechanisms and to provide cost-effective programs and services to customers. In the event that lower cost alternatives for generation, as a result of changing regulatory policies, subsidies or advances in technology, are added to the available generation supply, they could displace current resources or reduce the price at which market participants sell their electricity.

AEP is exposed to nuclear generation risk. (Applies to AEP and I&M)

I&M owns the Cook Plant, which consists of two nuclear generating units for a rated capacity of 2,296 MWs, or about a tenth of the regulated generating capacity in the AEP System as of December 31, 2025. AEP and I&M are, therefore, subject to the risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health due to an adverse incident/event resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials such as SNF.
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations.
- Uncertainties with respect to contingencies and assessment amounts triggered by a loss event (federal law requires owners of nuclear units to purchase the maximum available amount of nuclear liability insurance unless the NRC specifies a lesser amount and potentially contribute to the coverage for losses of others).

- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

There can be no assurance that I&M's preparations or risk mitigation measures will be adequate if these risks are triggered.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants. In addition, if an incident did occur, it could harm results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Moreover, a major incident at any nuclear facility in the U.S. could require AEP or I&M to make material contributory payments.

Costs associated with the operation (including fuel), maintenance and retirement of nuclear plants continue to be more significant and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the operation of nuclear facilities. Costs also may include replacement power, any unamortized investment at the end of the useful life of the Cook Plant (whether scheduled or premature), the carrying costs of that investment and retirement costs. The ability to obtain adequate and timely recovery of costs associated with the Cook Plant is not assured.

AEP subsidiaries are exposed to risks through participation in the market and transmission structures in various regional power markets that are beyond their control. (Applies to all Registrants)

Differences in the market and transmission structures in various regional power markets are likely to affect results. The rules governing the various RTOs, including SPP and PJM, may also change from time to time which could affect costs or revenues. Existing, new or changed rules of these RTOs could result in significant additional fees and increased costs to participate in those structures, including the cost of transmission and generation facilities built by others due to changes in rules and allocations, including transmission rate design. In addition, these RTOs may assess costs resulting from improved transmission reliability, reduced transmission congestion and firm transmission rights. As members of these RTOs, AEP's subsidiaries are subject to certain additional risks, including the allocation among existing members, of losses caused by unreimbursed defaults of other participants in these markets and resolution of complaint cases that may seek refunds of revenues previously earned by members of these markets.

AEP could be subject to higher costs and/or penalties related to mandatory reliability standards. (Applies to all Registrants)

Owners and operators of the bulk power transmission system are subject to mandatory reliability standards promulgated by the NERC and enforced by the FERC. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with new reliability standards may subject AEP to higher operating costs and/or increased capital expenditures. If AEP were found not to be in compliance with the mandatory reliability standards, AEP could be subject to sanctions, including substantial monetary penalties, which likely would not be recoverable from customers through regulated rates.

A substantial portion of the receivables of AEP Texas is concentrated in a small number of REPs, and any delay or default in payment could adversely affect its cash flows, financial condition and results of operations. (Applies to AEP and AEP Texas)

AEP Texas collects receivables from the distribution of electricity from REPs that supply the electricity it distributes to its customers. As of December 31, 2025, AEP Texas did business with approximately 146 REPs. Adverse economic conditions, structural problems in the market served by ERCOT or financial difficulties of one or more REPs could impair the ability of these REPs to pay for these services or could cause them to delay such payments. AEP Texas depends on these REPs to remit payments on a timely basis. In 2025, AEP Texas' two largest REPs accounted for 38% of its operating revenue. Any delay or default in payment by REPs could adversely affect cash flows, financial condition and results of operations. If a REP were unable to meet its obligations, it could consider, among various options, restructuring under the bankruptcy laws, in which event such REP might seek to avoid honoring its obligations, and claims might be made by creditors involving payments AEP Texas had received from such REP.

RISKS RELATED TO MARKET, ECONOMIC OR FINANCIAL VOLATILITY AND OTHER RISKS

AEP's financial performance may be adversely affected if AEP is unable to successfully operate facilities or perform certain corporate functions. (Applies to all Registrants)

Performance is highly dependent on the successful operation of generation, transmission and/or distribution facilities. Operating these facilities involves many risks, including:

- Operator error and breakdown or failure of equipment or processes.
- Operating limitations that may be imposed by environmental or other regulatory requirements.
- Labor disputes.
- Compliance with mandatory reliability standards, including mandatory cybersecurity standards.
- Information technology failure, including failure of AI technology, that impairs AEP's information technology infrastructure or disrupts normal business operations.
- Information technology failure that affects AEP's ability to access customer information or causes loss of confidential or proprietary data that materially and adversely affects AEP's reputation or exposes AEP to legal claims.
- Supply chain disruptions and inflation.
- Fuel or water supply interruptions caused by transportation constraints, adverse weather such as drought, non-performance by suppliers and other factors.
- Catastrophic events such as extreme weather, fires, earthquakes, explosions, hurricanes, tornadoes, winter storms, terrorism (including cyber-terrorism), floods or other similar occurrences.
- Fuel costs and related requirements triggered by financial stress in the coal industry.

Physical attacks or hostile cyber intrusions could severely impair operations, lead to the disclosure of confidential information and damage AEP's reputation. (Applies to all Registrants)

Risks from cybersecurity and physical threats to energy infrastructure are increasing. Threat actors, including sophisticated nation-state actors and criminal groups, exploit potential vulnerabilities in the electric utility industry, grid infrastructure and other energy infrastructures. Attacks and disruptions, which could involve physical, cyber and hybrid targeting of physical and cyber assets, are increasingly sophisticated and dynamic. The increased implementation of, and reliance on, information technologies and networks to manage business operations, including the operation of technical systems, as well as AEP's use of numerous vendors and suppliers, create additional points of vulnerability that could be, and in certain instances have been, exploited by malicious threat actors. Several U.S. government agencies have warned that the energy sector and its supply chains are subject to increasing risks of physical attacks, ransomware attacks and cybersecurity threats, and that the risks may escalate during periods of heightened geopolitical tensions. In addition, the rapid evolution and increased adoption of AI technologies may intensify AEP's cybersecurity risks.

A security breach of AEP's physical assets or information systems, or those of AEP's competitors, vendors, business partners and interconnected entities (including RTOs) could materially impact AEP by, among other things, impairing the availability of electricity transmitted and distributed by AEP and/or the reliability of generation, transmission and distribution systems, damaging grid infrastructure, interrupting critical business functions, impairing the availability of vendor services and materials that AEP relies on to maintain its operations, or by leading to the theft or inappropriate release of certain types of information, including critical infrastructure information, system data and architecture, sensitive customer, vendor, or employee data, or other confidential data.

AEP has not identified any cybersecurity incidents that have materially affected or are reasonably likely to materially affect its business strategy, results of operation or financial condition.

If a material physical or cybersecurity breach or disruption were to occur, AEP's reputation could be negatively affected, customer confidence in AEP could be diminished and AEP could be subject to legal claims, regulatory exposure, loss of revenues, and increased costs, including infrastructure repairs or operations shutdown, all of which could materially affect AEP's financial condition and materially damage its business reputation. Moreover, the amount and scope of insurance maintained against losses resulting from any such security breaches or disruptions may not be sufficient to cover losses or otherwise adequately compensate for any resulting business disruptions. The continued increase in federal and state regulatory requirements related to cybersecurity and evolving threat actor-capabilities could require changes to measures currently undertaken by AEP or to its business operations and could adversely affect its financial condition.

The failure of AEP or third-party vendor information technology systems, or the failure to enhance existing information technology systems and implement new technology, could adversely affect AEP. (Applies to all Registrants)

AEP's operations are dependent upon the proper functioning of its internal systems, including the information technology systems that support underlying business processes. Any significant failure or malfunction of such information technology systems may result in disruptions of operations. AEP's information technology systems are dependent upon global communications and cloud service providers, as well as their respective vendors, many of whom have at some point experienced significant system failures and outages in the past and may experience such failures and outages in the future. These providers' systems are susceptible to cybersecurity and data breaches, outages from fire, floods, power loss, telecommunications failures, break-ins and similar events. Failure to prevent or mitigate data loss from system failures or outages could materially affect AEP's results of operations, financial position and cash flows.

The amount of taxes imposed on AEP could change. (Applies to all Registrants)

AEP is subject to income taxation at the federal level and by certain states and municipalities. In determining AEP's income tax liability for these jurisdictions, management monitors changes to the applicable tax laws and related regulations, administrative interpretations and judicial determinations, including tax incentives and credits designed to support the sale of energy from utility scale renewable energy facilities. While management believes AEP complies with current prevailing laws, one or more taxing jurisdictions could seek to impose incremental or new taxes on the company. At the federal level, management is monitoring the potential for changes in current tax policy, including tax rates, tax credits and incentives. Any adverse developments in tax laws, incentives, credits or regulations, including legislative changes, judicial holdings or administrative interpretations, could have a material and adverse effect on financial condition and results of operations.

Changes in U.S. or foreign trade policies, including the imposition of tariffs and other protectionist trade measures, and other factors beyond AEP's control may adversely impact future net income and cash flows and financial condition.

Executive actions have been taken and additional measures proposed that are intended to alter the U.S. approach to international trade policy, the terms of certain existing bilateral or multi-lateral trade agreements and trading arrangements with foreign countries. Such changes to U.S. international trade policy, and any retaliatory trade measures that foreign governments may take in response, including the imposition of tariffs, sanctions, export or import controls, or other measures that restrict international trade, or the threat of such actions, could result in additional increases in the cost of certain goods, services and cost of capital and exacerbate supply chain issues. In addition, related geopolitical and domestic political developments, such as existing and potential trade wars, uncertainty regarding changes in trade policy, and other events beyond AEP's control, have increased and may continue to increase levels of political and economic unpredictability globally and the volatility of global financial markets. As a result, prevailing economic conditions may reduce future net income and cash flows and negatively impact financial condition.

If AEP is unable to access capital markets or insurance markets on reasonable terms, for any reason, including negative publicity, it could reduce future net income and cash flows and negatively impact financial condition. (Applies to all Registrants)

AEP relies on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows. AEP also relies on access to insurance markets to assist in managing its risk and liability profile. Volatility, increased interest rates 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. In addition, AEP has exposure to international banks, including those in Europe, Canada and Asia. Disruptions in these markets could reduce or restrict AEP's ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2025, approximately 8%, 23% and 15% of the Registrants' available credit facilities were with European, Canadian, and Asian banks, respectively.

In the past, certain sources of insurance and debt and equity capital have expressed unwillingness to provide insurance for or to invest in companies, such as AEP, that rely on fossil fuels. The public holds diverse and often conflicting views on the use of fossil fuels. AEP has multiple stakeholders, including shareholders, customers, associates, federal and state regulatory authorities and the communities in which AEP operates, and these stakeholders will often have differing priorities and expectations regarding issues related to the use of fossil fuels. Any adverse publicity in connection with AEP's use of fossil fuels could curtail availability from certain sources of capital. Additionally, certain terms that AEP may be required to include in its financing agreements and arrangements may not be acceptable to certain investors, which could limit the availability of, or increase the cost of, capital.

If sources of capital for AEP are reduced, capital costs could increase materially. Restricted access to capital or insurance markets and/or increased borrowing costs or insurance premiums could reduce future net income and cash flows and negatively

impact financial condition. If AEP is not able to access debt or equity at competitive rates or at all, the ability to finance its operations and implement its strategy and business plan as scheduled could be adversely affected. An inability to access debt and equity may limit AEP's ability to pursue improvements or acquisitions that it may otherwise rely on for future growth.

Shareholder activism could cause AEP to incur significant expense, hinder execution of AEP's business strategy and impact AEP's stock price. (Applies to all Registrants)

Shareholder activism, which can take many forms and arise in a variety of situations, could result in substantial costs and divert management's and the AEP Board's attention and resources from AEP's business. Additionally, such shareholder activism could give rise to perceived uncertainties as to AEP's future, adversely affect AEP's relationships with its employees, customers or service providers and make it more difficult to attract and retain qualified personnel. Also, AEP may be required to incur significant fees and other expenses related to activist shareholder matters, including for third-party advisors. AEP's stock price could be subject to significant fluctuation or otherwise be adversely affected by the events, risks and uncertainties of any shareholder activism.

Downgrades in AEP's credit ratings could negatively affect its ability to access capital. (Applies to all Registrants)

The credit ratings agencies periodically review AEP's capital structure and the quality and stability of earnings and cash flows. From time to time, AEP's financial metrics have approached, and may in the future approach, thresholds designated by the credit rating agencies for potential ratings downgrades. Any negative ratings actions could constrain the capital available to AEP and could limit access to funding for operations. AEP's business is capital intensive, and AEP is dependent upon the ability to access capital at rates and on terms management determines to be attractive. If AEP's ability to access capital becomes significantly constrained, AEP's interest costs will likely increase and that could reduce future net income and cash flows and negatively impact financial condition.

AEP and AEPTCo have no income or cash flow apart from dividends paid or other payments due from their subsidiaries. (Applies to AEP and AEPTCo)

AEP and AEPTCo are holding companies and have no operations of their own. Their ability to meet their financial obligations associated with their indebtedness and to pay dividends is primarily dependent on the earnings and cash flows of their operating subsidiaries, primarily their regulated utilities, and the ability of their subsidiaries to pay dividends to them or repay loans from them. Their subsidiaries are separate and distinct legal entities that have no obligation (apart from loans from AEP or AEPTCo) to provide them with funds for their payment obligations, whether by dividends, distributions or other payments. Payments to AEP or AEPTCo by their subsidiaries are also contingent upon their earnings and business considerations. AEP and AEPTCo indebtedness and dividends are structurally subordinated to all subsidiary indebtedness. Accordingly, restrictions on the ability of AEP's subsidiaries to pay dividends to AEP and AEPTCo could materially impact the amount of cash flow available to, and received by, AEP and AEPTCo.

Volatility in the securities markets, interest rates, and other factors could substantially increase defined benefit pension and other postretirement plan costs and the costs of nuclear decommissioning. (Applies to all Registrants and to AEP and I&M with respect to the costs of nuclear decommissioning)

The costs of providing pension and other postretirement benefit plans are dependent on a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plan, changes in actuarial assumptions, future government regulation, changes in life expectancy and the frequency and amount of AEP's required or voluntary contributions made to the plans. Changes in actuarial assumptions and differences between the assumptions and actual values, as well as a significant decline in the value of investments that fund the pension and other postretirement plans, if not offset or mitigated by a decline in plan liabilities, could increase pension and other postretirement expense, and AEP could be required from time to time to fund the pension plan with significant amounts of cash. Such cash funding obligations could have a material impact on liquidity by reducing cash flows and could negatively affect results of operations.

Additionally, I&M holds a significant amount of assets in its nuclear decommissioning trusts to satisfy obligations to decommission its nuclear plant. The rate of return on assets held in those trusts can significantly impact both the costs of decommissioning and the funding requirements for the trusts.

Supply chain disruptions, tariffs and inflation could negatively impact operations and corporate strategy. (Applies to all Registrants)

AEP's operations and business plans depend on the global supply chain to procure the equipment, materials and other resources necessary to build and provide services in a safe and reliable manner. The delivery of components, materials, equipment and other resources that are critical to AEP's business operations and corporate strategy are affected by domestic and global supply chain upheaval. This can result in the shortage of critical items. International tensions from any source, including the ramifications of regional conflict or increased tariffs, could further exacerbate global supply chain upheaval. Any disruptions and shortages could adversely impact business operations and corporate strategy. The current administration has implemented tariffs on certain imported goods and may impose additional tariffs. The constraints in the supply chain could restrict the availability and delay the construction, maintenance or repair of items that are needed to support normal operations or are required to execute on AEP's corporate strategy for continued capital investment in utility equipment and impact AEP's strategy to transition its generation fleet. These disruptions and constraints could reduce future net income and cash flows and impact financial condition.

The United States economy has experienced an inflationary environment and supply chain disruptions have contributed to higher prices of components, materials, equipment and other needed commodities. A prolonged continuation or a further increase in the severity of supply chain and inflationary disruptions, including increased tariffs, could result in additional increases in the cost of certain goods, services and cost of capital and further extend lead times. AEP typically recovers increases in capital expenses from customers through rates in regulated jurisdictions. Failure to recover increased capital costs could reduce future net income and cash flows and possibly harm AEP's financial condition. Increases in inflation raises costs for labor, materials and services, and failure to secure these on reasonable terms may adversely impact financial condition.

AEP's results of operations and cash flows may be negatively affected by a lack of growth or slower growth in the number of customers, a decline in customer demand or a recession. (Applies to all Registrants)

Growth in customer accounts and growth of customer usage each directly influence demand for electricity and the need for additional power generation and delivery facilities. Customer growth and customer usage are affected by a number of factors outside the control of AEP, such as economic and demographic conditions, population changes, job and income growth, housing starts, new business formation and the overall level of economic activity. Some or all of these factors could impact the demand for electricity.

Failure to attract and retain an appropriately qualified workforce and management could harm results of operations. (Applies to all Registrants)

Certain events, such as an aging workforce without appropriate replacements, mismatch of skillset or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include potential higher rates of existing employee departures, lack of resources, loss of knowledge and a lengthy time period associated with skill development. Advancements in artificial intelligence and other emerging technologies may require significant changes to the size, skills, and composition of AEP's workforce, and the inability to adapt to these evolving talent needs could exacerbate existing workforce challenges and adversely affect AEP's operations and financial performance. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect the ability to manage and operate the business. If AEP is unable to successfully attract and retain an appropriately qualified workforce, operations may be negatively impacted and future net income and cash flows may be reduced.

Difficulties in sustaining leadership continuity could negatively impact AEP's business and financial condition. The ability to maintain strong leadership relies on effective succession planning, and gaps in preparing or transitioning individuals into critical roles may impact performance.

Changes in the price of purchased power and commodities, the cost of procuring fuel, emission allowances for criteria pollutants and the costs of transport may increase AEP's cost of purchasing and producing power, impacting financial performance. (Applies to all Registrants except AEP Texas, AEPTCo and OPCo)

AEP is exposed to changes in the price and availability of purchased power and fuel (including the cost to procure coal and gas) and the price and availability to transport fuel.

- AEP is exposed to changes in the price and availability of fuel, including coal, natural gas and uranium, as existing contracts for the supply of such fuel end or are not honored.

- The inability to procure fuel at costs that are economical could cause AEP to retire generating capacity prior to the end of its useful life.
- AEP is exposed to changes in the price and availability of emission allowances.
- AEP is exposed to changes in the price and availability of diesel, the primary fuel used in transporting coal by barge.

While AEP typically recovers such fuel-related expenses pursuant to rate recovery mechanisms in regulated jurisdictions, the failure to recover these costs could reduce future net income and cash flows and possibly harm AEP's financial condition.

Prices for coal, natural gas and emission allowances have shown material swings in the past. Changes in the cost of purchased power, fuel or emission allowances and changes in the relationship between such costs and the market prices of power could reduce future net income and cash flows and negatively impact financial condition. In addition, actual power prices and fuel costs will differ from those assumed in financial projections used to value trading and marketing transactions, and those differences may be material. As a result, as those transactions are marked-to-market, they may impact future results of operations and cash flows and impact financial condition.

AEP is subject to physical and financial risks associated with climate change. (Applies to all Registrants)

Climate change creates physical and financial risk. Physical risks from climate change may include an increase in sea level and changes in weather conditions, such as changes in precipitation and extreme weather events, such as fires. Customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes.

Increased energy use due to weather changes may require AEP to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may affect financial condition through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of the AEP service territory could also have an impact on revenues. AEP buys and sells electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand on AEP's own and/or other systems may raise electricity prices as AEP buys short-term energy to serve AEP's own system, which would increase the cost of energy AEP provides to customers.

Severe weather and weather-related events impact AEP's service territories, primarily when thunderstorms, tornadoes, hurricanes, fires, floods and snow or ice storms occur. To the extent the frequency and intensity of extreme weather events and storms increase, AEP's cost of providing service will increase, including the costs and the availability of procuring insurance related to such impacts, and these costs may not be recoverable. Changes in wind patterns or in precipitation resulting in droughts, water shortages or floods could adversely affect operations, principally wind generation facilities for changes in wind patterns and the fossil fuel generating units for changes in precipitation. A change in wind patterns or a negative impact to water supplies due to long-term drought conditions or severe flooding could adversely impact AEP's ability to provide electricity to customers, as well as increase the price they pay for energy. AEP may not recover all costs related to mitigating these physical and financial risks.

To the extent climate change impacts a region's economic health, it may also impact revenues. AEP's financial performance is tied to the health of the regional economies AEP serves. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods and services, impacts the economic health of the communities within AEP's service territories. Climate change may impact the economy, which could impact sales and revenues. The cost of additional regulatory requirements, such as regulation of carbon dioxide emissions, could impact the availability of goods and prices charged by AEP's suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and carbon dioxide emissions as a financial risk, this could negatively affect AEP's ability to access capital markets or cause AEP to receive less than ideal terms and conditions in capital markets.

The occurrence of one or more wildfires could cause tremendous loss, impact the market value and credit ratings of Registrants' securities and have a material adverse effect on Registrants' financial condition. (Applies to all Registrants)

More frequent and severe drought conditions, extreme swings in amount and timing of precipitation, changes in vegetation, unseasonably warm temperatures, very low humidity, stronger winds and other factors have increased the duration of the wildfire season and the potential impact of an event. AEP's infrastructure could pose risks to safety and system reliability and wildfire mitigation initiatives may not be successful or effective in preventing or reducing wildfire-related events. Wildfires can occur even when effective mitigation procedures are followed. Despite AEP's early-stage wildfire mitigation initiatives, a wildfire could be ignited, spread and cause damages, which could subject AEP to significant liability. Other potential risks associated with wildfires include the inability to secure sufficient insurance coverage, increased costs for insurance and

mitigation efforts, regulatory recovery risk, litigation risk, and the potential for a credit downgrade and subsequent additional costs to access capital markets.

The generation, transmission and distribution of electricity are dangerous and involve inherent risks of damage to private property and injury to AEP's workforce and the general public. (Applies to all Registrants)

Electricity poses hazards for AEP's workforce and the general public in the event that either comes in contact with electrical current or equipment, including through energized downed power lines or through equipment malfunctions. In addition, the risks associated with the operation of transmission and distribution assets and power generation and storage facilities include public and workforce safety issues and the risk of utility assets causing or contributing to wildfires, explosions, mechanical failure, unscheduled downtime, equipment interruptions, remediation, chemical and oil spills, discharges or releases of toxic or hazardous substances or gases and other environment risks. Deaths, injuries and property damage caused by such events can subject AEP to liability that, despite the existence of insurance coverage, can be significant. In addition, AEP may be held responsible for the actions of its contractors. No assurance can be given that future losses will not exceed the limits of AEP's or its contractors' insurance coverage. An occurrence of any of these hazards may also result in suspension of operations and the imposition of civil or criminal penalties.

Adverse outcomes in AEP's material legal proceedings could materially and adversely affect AEP's results of operations and financial condition. (Applies to all Registrants)

AEP is involved in legal proceedings, claims and litigation arising out of its business operations, the most significant of which are summarized in Note 6 - Commitments, Guarantees and Contingencies. Management cannot predict the outcome of such legal proceedings. Adverse outcomes in these proceedings could require significant expenditures that could reduce future net income and cash flows and negatively impact financial condition.

Disruptions at power generation facilities owned by third-parties could interrupt the sales of transmission and distribution services. (Applies to AEP, AEP Texas and OPCo)

AEP Texas and OPCo transmit and distribute electric power obtained from power generation facilities owned by third-parties or affiliates. If power generation is disrupted or if power generation capacity is inadequate, sales of transmission and distribution services may be diminished or interrupted, and results of operations, financial condition and cash flows could be adversely affected.

Most of the real property rights on which the assets of AEPTCo are situated result from affiliate license agreements and are dependent on the terms of the underlying easements and other rights of its affiliates. (Applies to AEPTCo)

AEPTCo does not hold title to the majority of real property on which its electric transmission assets are located. Instead, under the provisions of certain affiliate contracts, it is permitted to occupy and maintain its facilities upon real property held by the respective AEP subsidiary utility affiliate that overlay its operations. The ability of AEPTCo to continue to occupy such real property is dependent upon the terms of such affiliate contracts and upon the underlying real property rights of these utility affiliates, which may be encumbered by easements, mineral rights and other similar encumbrances that may affect the use of such real property. AEP can give no assurance that (a) the relevant AEP subsidiary utility affiliates will continue to be affiliates of AEPTCo, (b) suitable replacement arrangements can be obtained in the event that the relevant AEP subsidiary utility affiliates are not its affiliates and (c) the underlying easements and other rights are sufficient to permit AEPTCo to operate its assets in a manner free from interruption.

Compliance with legislative and regulatory requirements may lead to increased costs and result in penalties. (Applies to all Registrants)

Business activities of electric utilities and related companies are heavily regulated, primarily through national and state laws and regulations of general applicability, including laws and regulations related to working conditions, health and safety, equal employment opportunity, employee benefit and other labor and employment matters, laws and regulations related to competition and antitrust matters. Many agencies employ mandatory civil penalty structures for regulatory violations. Registrants are subject to the jurisdiction of many federal and state agencies, including the FERC, NERC, Commodity Futures Trading Commission, Federal EPA, NRC, Occupational Safety and Health Administration, the SEC and the United States Department of Justice which may impose significant civil and criminal penalties to enforce compliance requirements relative to AEP's business, which could have a material adverse impact on results of operations and cash flows and impact financial condition.

The impact of new laws, regulations and policies and the related interpretations, as well as changes in enforcement practices or

regulatory scrutiny generally cannot be predicted, and changes in applicable laws, regulations and policies and the related interpretations and enforcement practices may require extensive system and operational changes, be difficult to implement, increase AEP's operating costs, require significant capital expenditures, or adversely impact the cost or attractiveness of the products or services AEP offers, or result in adverse publicity and harm AEP's reputation.

RISKS RELATED TO OWNING AND OPERATING GENERATION ASSETS AND SELLING POWER

Costs of compliance with existing and evolving environmental laws are significant. (Applies to all Registrants except AEPTCo)

AEP's operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. A majority of the electricity generated by AEP is produced by the combustion of fossil fuels. Emissions of nitrogen and sulfur oxides, mercury and particulates and the discharge and disposal of solid waste (including coal-combustion residuals or CCR) resulting from fossil fueled generation plants are subject to increased regulations, controls and mitigation expenses. Compliance with the sometimes evolving criteria of these legal requirements (including any newly adopted requirements and/or more stringent application of existing regulations, including CCR requirements that could result from either agency action or litigation) can be difficult. While management believes AEP complies with current prevailing laws and regulations, there can be no assurance that AEP's efforts will be deemed to have been sufficient in a litigation or regulatory review context. Compliance requires AEP to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees, disposal, remediation and permits at AEP facilities and could require AEP to retire generating capacity prior to the end of its estimated useful life. Costs of compliance with environmental statutes and regulations, and penalties or damages assessed for noncompliance, could reduce future net income and negatively impact financial condition, especially if emission limits, CCR waste discharge and/or discharge disposal obligations are tightened, more extensive operating and/or permitting requirements are imposed or additional substances or facilities become regulated.

Regulation of GHG emissions could materially increase costs to AEP and its customers or cause some electric generating units to be uneconomical to operate or maintain. (Applies to all Registrants except AEP Texas, AEPTCo and OPCo)

Federal or state laws or regulations may be adopted that could impose new or additional limits on the emissions of greenhouse gases, including, but not limited to, carbon dioxide and methane, from electric generation units using fossil fuels like coal. The potential effects of greenhouse gas emission limits on AEP's electric generation units are subject to significant uncertainties based on, among other things, the timing of the implementation of any new requirements, the required levels of emission reductions, the nature of any market-based or tax-based mechanisms adopted to facilitate reductions, the relative availability of greenhouse gas emission reduction offsets, the development of cost-effective, commercial-scale carbon capture and storage technology and supporting regulations and liability mitigation measures, and the range of available compliance alternatives.

AEP's results of operations could be materially adversely affected to the extent that new federal or state laws or regulations impose any new greenhouse gas emission limits. Any future limits on greenhouse gas emissions could create substantial additional costs in the form of taxes or emissions allowances, require significant capital investment in carbon capture and storage technology, fuel switching, or the replacement of high-emitting generation facilities with lower-emitting generation facilities and/or could cause AEP to retire generating capacity prior to the end of its estimated useful life. Although AEP typically recovers environmental expenditures, there can be no assurance in the future that AEP can recover such costs which could reduce future net income and cash flows and possibly harm financial condition. Further, real or alleged violations of environmental regulations, including those related to climate change, could reduce future net income and cash flows and possibly harm financial condition.

AEP may be unable to procure or construct generation capacity when needed or to recover the costs of such generation capacity. (Applies to all Registrants except AEP Texas, AEPTCo and OPCo)

AEP's capacity obligations are subject to a number of factors including load growth, requirements that can be imposed by the states, RTOs and other jurisdictions in which it operates or participates as a member and the retirement of existing generating facilities. AEP must obtain new and replacement generation to comply with prevailing capacity needs and reserve obligations. AEP's ability to acquire, retrofit and/or construct power generation facilities in a timely manner and within budget is contingent upon many variables and subject to substantial risks. These variables include, but are not limited to, project management expertise, escalating costs for capital, materials, labor, and environmental compliance, changes in RTO cost allocation and cost recovery, reliance on suppliers for timely and satisfactory performance, delays and cost increases, and supply chains and material constraints, including those that may result from major storm events. Delays in obtaining permits, challenges in securing suitable land for the siting, shortages in materials and qualified labor, levels of public support or opposition, suppliers and contractors not performing as expected or required under their contracts and/or experiencing financial problems that inhibit

their ability to fulfill their obligations under contracts, changes in the scope and timing of projects, poor quality initial cost estimates from contractors, the inability to raise capital on favorable terms, changes in commodity prices affecting revenue, fuel costs, or materials costs, downward changes in the economy, changes in law or regulation, including environmental compliance requirements, further direct and indirect trade and tariff issues, supply chain delays or disruptions, and other events beyond AEP's control may occur that may materially affect the schedule, cost, and performance of needed acquisitions or construction projects. If these projects or other capital improvements are significantly delayed or become subject to cost overruns or cancellation, AEP could incur additional costs and termination payments or face increased risk of potential write-off of the investment in the project. In addition, AEP could be exposed to higher costs, penalties and market volatility, which could affect cash flow and cost recovery, should one or more applicable regulator decline to approve the acquisition or construction of the project or new generation needed to meet the reliability needs of customers at the lowest reasonable cost.

Courts adjudicating nuisance and other similar claims in the future may order AEP to pay damages or to limit or reduce emissions. (Applies to all Registrants except AEP Texas and AEPTCo)

In the past, there have been several cases seeking damages based on allegations of federal and state common law nuisance in which AEP, among others, were defendants. In general, the actions allege that emissions from the defendants' power plants constitute a public nuisance. The plaintiffs in these actions generally seek recovery of damages and other relief. If future actions are resolved against AEP, substantial modifications or retirement of AEP's existing coal-fired power plants could be required, and AEP might be required to purchase power from third-parties to fulfill AEP's commitments to supply power to AEP customers. This could have a material impact on revenues. In addition, AEP could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay damages or penalties and/or halt operations. Unless recovered, those costs could reduce future net income and cash flows and harm financial condition. Moreover, results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

Commodity trading and marketing activities are subject to inherent risks which can be reduced and controlled but not eliminated. (Applies to all Registrants except AEP Texas, AEPTCo and OPCo)

AEP routinely has open trading positions in the market, within guidelines set by AEP, resulting from the management of AEP's trading portfolio. To the extent open trading positions exist, fluctuating commodity prices can improve or diminish financial results and financial position. AEP's power trading activities also expose AEP to risks of commodity price movements. To the extent that AEP's power trading does not hedge the price risk associated with the generation it owns, or controls, AEP would be exposed to the risk of rising and falling spot market prices. In connection with these trading activities, AEP routinely enters into financial contracts, including futures and options, OTC options, financially-settled swaps and other derivative contracts. These activities expose AEP to risks from price movements. If the values of the financial contracts change in a manner AEP does not anticipate, it could harm financial position or reduce the financial contribution of trading operations.

Parties with whom AEP has contracts may fail to perform their obligations, which could harm AEP's results of operations. (Applies to all Registrants)

AEP sells power from its generation facilities into the spot market and other competitive power markets on a contractual basis. AEP also enters into contracts to purchase and sell electricity, natural gas, emission allowances, renewable energy credits and coal as part of its power marketing and energy trading operations. AEP is exposed to the risk that counterparties that owe AEP money or the delivery of a commodity, including power, could breach their obligations. Should the counterparties to these arrangements fail to perform, AEP may be forced to enter into alternative hedging arrangements or honor underlying commitments at then-current market prices that may exceed AEP's contractual prices, which would cause financial results to be diminished and AEP might incur losses. Although estimates take into account the expected probability of default by a counterparty, actual exposure to a default by a counterparty may be greater than the estimates predict.

AEP relies on electric transmission facilities that AEP does not own or control. If these facilities do not provide AEP with adequate transmission capacity, AEP may not be able to deliver wholesale electric power to the purchasers of AEP's power. (Applies to all Registrants)

AEP depends on transmission facilities owned and operated by other nonaffiliated power companies to deliver the power AEP sells at wholesale. This dependence exposes AEP to a variety of risks. If transmission is disrupted, or transmission capacity is inadequate, AEP may not be able to sell and deliver AEP wholesale power. If a region's power transmission infrastructure is inadequate, AEP's recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

OVEC may require additional liquidity and other capital support. (Applies to AEP, APCo, I&M and OPCo)

AEP and several nonaffiliated utility companies own OVEC. The Inter-Company Power Agreement (ICPA) defines the rights and obligations and sets the power participation ratio of the parties to it. Under the ICPA, parties are entitled to receive and are obligated to pay for all OVEC capacity (approximately 2,400 MWs) in proportion to their respective power participation ratios. The aggregate power participation ratio of APCo, I&M and OPCo is 43.47%. If a party fails to make payments owed by it under the ICPA, OVEC may not have sufficient funds to honor its payment obligations, including its ongoing operating expenses as well as its indebtedness. As of December 31, 2025, OVEC has outstanding indebtedness of approximately $873 million, of which APCo, I&M and OPCo are collectively responsible for $379 million through the ICPA. Although they are not an obligor or guarantor, APCo, I&M and OPCo are responsible for their respective ratio of OVEC's outstanding debt through the ICPA and if OVEC's indebtedness is accelerated for any reason, there is risk that APCo, I&M and/or OPCo may be required to pay some or all of such accelerated indebtedness in amounts equal to their aggregate power participation ratio of 43.47%.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Cybersecurity is a critical component of AEP's risk management framework. As an electric utility operating critical infrastructure, AEP is subject to mandatory requirements under applicable federal, state, and industry standards. AEP maintains a risk-based cybersecurity program designed to protect the confidentiality, integrity, and availability of its information technology, operational technology, and critical infrastructure assets.

Cybersecurity Risk Management and Strategy

AEP's cybersecurity risk management program is designed to identify, assess, and manage risks from cybersecurity threats, including those posed by third parties. The program incorporates a defense-in-depth approach, leverages partnerships with government and peers to assess the evolving threats and aligns with recognized industry standards and regulatory requirements applicable to electric utilities.

Key elements of AEP's cybersecurity program include, among others:

- Continuous monitoring and detection of cyber threats;
- Vulnerability assessments and penetration testing;
- Incident response planning and exercises;
- Business continuity and disaster recovery planning;
- Security awareness training, including advanced phishing simulations;
- Third-party risk management, including vendor due diligence and contractual controls;
- Cybersecurity insurance coverage.

AEP regularly evaluates and updates its cybersecurity controls, processes, and technologies in response to the evolving threat landscape and regulatory developments. We leverage both internal expertise and external partners to assist with assessments, testing, and program maturity evaluations.

Governance and Oversight

AEP's Board of Directors, through the Technology Committee, oversees the cybersecurity program and our approach to cyber risk management. The Technology Committee receives periodic updates from management regarding cybersecurity risks, the threat environment, and the status of AEP's security programs, including significant incidents, if any.

Management's Role and Expertise

Management is responsible for implementing and maintaining AEP's cybersecurity programs. Day-to-day oversight is led by AEP's Senior Vice President (SVP) of Enterprise Security, Resilience, and National Security Policy who reports to AEP's Chief Executive Officer. The SVP for Enterprise Security, Resilience, and National Security Policy has expertise in electricity sector risk management, critical infrastructure protection, cybersecurity, and incident response. This individual also oversees and leads AEP's engagements with Federal agencies on cybersecurity and physical security threat information sharing and

partnerships with the Department of Homeland Security, Federal Bureau of Investigation, Department of Energy, and the intelligence community. The SVP for Enterprise Security, Resilience, and National Security Policy also works closely with AEP's Chief Information Officer, Generation, Transmission, and Distribution operations leadership, along with legal, compliance, internal audit, and business resilience to help ensure cybersecurity risks are identified, assessed, and managed across the enterprise. Management also provides relevant cybersecurity updates to the Audit Committee.

AEP has not identified any cybersecurity incidents that have materially affected or are reasonably likely to materially affect its business strategy, results of operations, or financial condition.

ITEM 2. PROPERTIES

GENERATION FACILITIES

The tables below summarize the net maximum capacity of AEP's owned generation plants as of December 31, 2025. AEP subsidiaries serve customer electricity needs from these facilities and from purchased power in the PJM and SPP markets based on demand and other economic conditions. AEP's regulated subsidiaries have approved recovery mechanisms in retail jurisdictions that recover the cost of prudently incurred fuel, purchased power and other expenses.

Vertically Integrated Utilities Segment

AEGCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Rockport (a)	2	IN	Steam - Coal	1,310	1984

(a) AEGCo owns a 50% interest in the Rockport Plant units. I&M owns the remaining 50%. Figures presented reflect only the portion owned by AEGCo.

APCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Ceredo	6	WV	Natural Gas	516	2001
Dresden	3	OH	Natural Gas	665	2012
Smith Mountain	5	VA	Pumped Storage	585	1965
Amos	3	WV	Steam - Coal	2,950	1971
Mountaineer	1	WV	Steam - Coal	1,320	1980
Clinch River	2	VA	Steam - Natural Gas	465	1958
Hydro (Various Plants)	Various	VA	Hydro	158	1906-1964
Hydro (Various Plants)	Various	WV	Hydro	53	1935-1938
Amherst	NA	VA	Solar	5	2023
Top Hat	NA	IL	Wind	204	2025
Total MWs				6,921	

NA Not applicable.

I&M

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Rockport (a)	2	IN	Steam - Coal	1,310	1984
Cook	2	MI	Steam - Nuclear	2,296	1975
Hydro (Various Plants)	Various	IN	Hydro	7	1904-1913
Hydro (Various Plants)	Various	MI	Hydro	13	1908-1923
Solar (Various Plants)	NA	IN	Solar	31	2016-2021
Solar (Various Plants)	NA	MI	Solar	5	2016
Total MWs				3,662	

(a) I&M owns a 50% interest in the Rockport Plant units. AEGCo owns the remaining 50%. Figures presented reflect only the portion owned by I&M.
NA Not applicable.

KPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Mitchell (a)	2	WV	Steam - Coal	780	1971
Big Sandy	1	KY	Steam - Natural Gas	295	1963
Total MWs				1,075	

(a) KPCo owns a 50% interest in the Mitchell Plant units. WPCo owns the remaining 50%. Figures presented reflect only the portion owned by KPCo.

PSO

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Comanche	3	OK	Natural Gas	228	1973
Green Country	3	OK	Natural Gas	904	2002
Northeastern, Unit 1	3	OK	Natural Gas	470	1961
Riverside, Units 3 and 4	2	OK	Natural Gas	160	2008
Southwestern, Units 4 and 5	2	OK	Natural Gas	166	2008
Weleetka	2	OK	Natural Gas	90	1975
Northeastern, Unit 3 (a)	1	OK	Steam - Coal	472	1979
Northeastern, Unit 2	1	OK	Steam - Natural Gas	435	1961
Riverside, Units 1 and 2	2	OK	Steam - Natural Gas	879	1974
Southwestern, Units 1, 2 and 3	3	OK	Steam - Natural Gas	446	1952
Tulsa	2	OK	Steam - Natural Gas	319	1956
North Central Wind Energy Facilities (b)	NA	OK	Wind	675	2021-2022
Rock Falls	NA	OK	Wind	155	2017
Flat Ridge IV	NA	KS	Wind	135	2025
Flat Ridge V	NA	KS	Wind	153	2025
Pixley	NA	KS	Solar	189	2025
Total MWs				5,876	

(a) Northeastern, Unit 3 operated on coal up through December 2025 and began to operate on natural gas beginning in January 2026.
(b) PSO owns a 45.5% interest and SWEPCo owns the remaining 54.5% interest in Sundance, Maverick and Traverse. Figures presented reflect only the portion owned by PSO.
NA Not applicable.

SWEPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Mattison	4	AR	Natural Gas	314	2007
Stall	3	LA	Natural Gas	535	2010
Flint Creek (a)	1	AR	Steam - Coal	259	1978
Turk (a)	1	AR	Steam - Coal	477	2012
Welsh (b)	2	TX	Steam - Coal	1,056	1977
Arsenal Hill	1	LA	Steam - Natural Gas	111	1960
Knox Lee	1	TX	Steam - Natural Gas	344	1950
Lieberman	2	LA	Steam - Natural Gas	219	1947
Wilkes	3	TX	Steam - Natural Gas	889	1964
Diversion Wind Farm	NA	TX	Wind	201	2024
North Central Wind Energy Facilities (c)	NA	OK	Wind	809	2021-2022
Wagon Wheel	NA	OK	Wind	598	2025
Total MWs				5,812	

(a) Jointly-owned with nonaffiliated entities. Figures presented reflect only the portion owned by SWEPCo. The Arkansas jurisdictional portion of SWEPCo's interest in Turk Plant is not in rate base.

(b) 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.

(c) SWEPCo owns a 54.5% interest and PSO owns the remaining 45.5% interest in Sundance, Maverick and Traverse. Figures presented reflect only the portion owned by SWEPCo.

NA Not applicable.

WPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Mitchell (a)	2	WV	Steam - Coal	780	1971

(a) WPCo owns a 50% in the Mitchell Plant units. KPCo owns the remaining 50%. Figures presented reflect only the portion owned by WPCo.

TRANSMISSION AND DISTRIBUTION FACILITIES

The AEP System has significant investments in transmission and distribution lines across its Vertically Integrated Utilities, Transmission and Distribution Utilities and AEP Transmission Holdco Segments.

TITLE TO PROPERTY

The AEP System's generating facilities are generally located on AEP owned property. The greater portion of the transmission and distribution lines of the AEP System has been constructed over property owned by third parties pursuant to easements or along public highways and streets pursuant to appropriate statutory authority. The rights of AEP's public utility subsidiaries in the realty on which their facilities are located are considered adequate for use in the conduct of their business. Minor defects and irregularities customarily found in title to properties of like size and character may exist, but such defects and irregularities do not materially impair the use of the properties. AEP's public utility subsidiaries generally have the right of eminent domain which permits them, if necessary, to acquire, perfect or secure titles to or easements on privately held lands used or to be used in their utility operations.

SYSTEM TRANSMISSION LINES AND FACILITY SITING

Laws in the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Tennessee, Texas, Virginia and West Virginia require prior approval of sites of generating facilities and/or routes of high-voltage transmission lines. AEP has experienced delays and additional costs in constructing facilities as a result of proceedings conducted pursuant to such statutes and in proceedings in which AEP's operating companies have sought to acquire rights-of-way through condemnation. These proceedings may result in additional delays and costs in future years.

CONSTRUCTION PROGRAM

With input from its state utility commissions, AEP subsidiaries regularly assess the adequacy of their transmission, distribution, generation and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment process, assumptions are being reviewed as new information becomes available and assessments and plans are modified, as appropriate. AEP forecasts approximately $12.2 billion of construction expenditures for 2026. Estimated construction 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. See the "Budgeted Capital Expenditures" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

POTENTIAL UNINSURED LOSSES

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 liabilities relating to damage to AEP's generation plants and costs of replacement power. Unless allowed to be recovered through rates, future losses or liabilities which are not completely insured could reduce net income and impact the financial conditions of AEP and subsidiaries. For risks related to owning a nuclear generating unit, see the "Nuclear Contingencies" section of Note 6 - Commitments, Guarantees and Contingencies for additional information.

ITEM 3. LEGAL PROCEEDINGS

For a discussion of material legal proceedings, see Note 6 - Commitments, Guarantees and Contingencies for additional information.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

AEP

In addition to the AEP Common Stock Information section below, the remaining information required by this item is incorporated herein by reference to (a) the material under the "Dividend Policy and Restrictions" section of Management's Discussion and Analysis of Financial Condition and Results of Operations and (b) Note 16 - Stock-Based Compensation.

During the quarter ended December 31, 2025, neither AEP nor its publicly-traded subsidiaries purchased equity securities that are registered by AEP or its publicly-traded subsidiaries pursuant to Section 12 of the Exchange Act other than in amounts that were not material as described in Note 16 referenced above.

AEP Texas, APCo, I&M, OPCo, PSO and SWEPCo

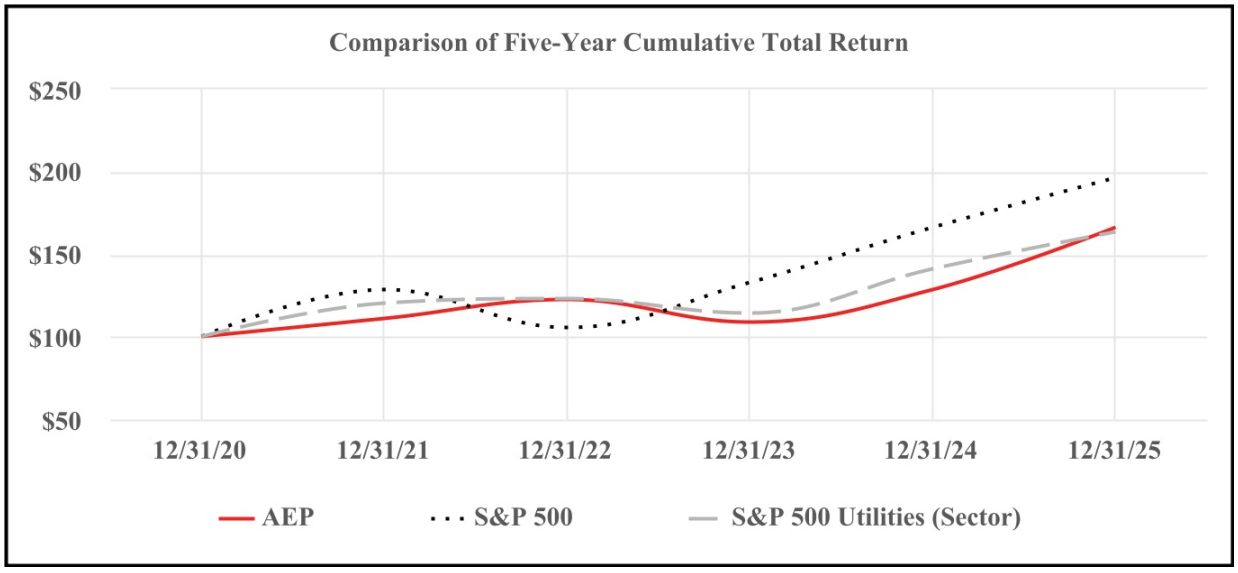
The common stock of these companies is held solely by AEP. For more information see the "Dividend Restrictions" section of Note 15 - Financing Activities.

AEPTCo

AEP owns the entire interest in AEPTCo through its wholly-owned subsidiary AEP Transmission Holdco.

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.

ITEM 6. RESERVED

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

AEP

The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Financial Condition and Results of Operations. Year-to-year comparisons between 2024 and 2023 have been omitted from this Form 10-K but may be found in "Management's Discussion and Analysis of Financial Condition" in Part II, Item 7 of AEP's Form 10-K for the fiscal year ended December 31, 2024.

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under Management's Discussion and Analysis of Financial Condition and Results of Operations.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

The information required by this item is incorporated herein by reference to the material under the "Quantitative and Qualitative Disclosures About Market Risk" section of Management's Discussion and Analysis of Financial Condition and Results of Operations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

2025 Annual Reports

American Electric Power Company, Inc. and Subsidiary Companies

AEP Texas Inc. and Subsidiaries

AEP Transmission Company, LLC and Subsidiaries

Appalachian Power Company and Subsidiaries

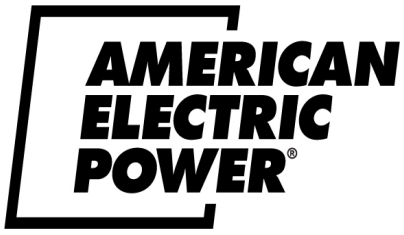
Indiana Michigan Power Company and Subsidiaries

Ohio Power Company and Subsidiaries

Public Service Company of Oklahoma

Southwestern Electric Power Company Consolidated

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



AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF ANNUAL REPORTS

	Page Number
American Electric Power Company, Inc. and Subsidiary Companies:	
Management's Discussion and Analysis of Financial Condition and Results of Operations	42
Report of Independent Registered Public Accounting Firm (PCAOB ID 238)	92
Management's Report on Internal Control Over Financial Reporting	95
Consolidated Financial Statements	96
AEP Texas Inc. and Subsidiaries:	
Management's Narrative Discussion and Analysis of Results of Operations	102
Report of Independent Registered Public Accounting Firm (PCAOB ID 238)	104
Management's Report on Internal Control Over Financial Reporting	106
Consolidated Financial Statements	107
AEP Transmission Company, LLC and Subsidiaries:	
Management's Narrative Discussion and Analysis of Results of Operations	113
Report of Independent Registered Public Accounting Firm (PCAOB ID 238)	115
Management's Report on Internal Control Over Financial Reporting	117
Consolidated Financial Statements	118
Appalachian Power Company and Subsidiaries:	
Management's Narrative Discussion and Analysis of Results of Operations	123
Report of Independent Registered Public Accounting Firm (PCAOB ID 238)	126
Management's Report on Internal Control Over Financial Reporting	128
Consolidated Financial Statements	129
Indiana Michigan Power Company and Subsidiaries:	
Management's Narrative Discussion and Analysis of Results of Operations	135
Report of Independent Registered Public Accounting Firm (PCAOB ID 238)	138
Management's Report on Internal Control Over Financial Reporting	140
Consolidated Financial Statements	141
Ohio Power Company and Subsidiaries:	
Management's Narrative Discussion and Analysis of Results of Operations	147
Report of Independent Registered Public Accounting Firm (PCAOB ID 238)	150
Management's Report on Internal Control Over Financial Reporting	152
Consolidated Financial Statements	153
Public Service Company of Oklahoma:	
Management's Narrative Discussion and Analysis of Results of Operations	158
Report of Independent Registered Public Accounting Firm (PCAOB ID 238)	161
Management's Report on Internal Control Over Financial Reporting	163
Financial Statements	164
Southwestern Electric Power Company Consolidated:	
Management's Narrative Discussion and Analysis of Results of Operations	170
Report of Independent Registered Public Accounting Firm (PCAOB ID 238)	173
Management's Report on Internal Control Over Financial Reporting	175
Consolidated Financial Statements	176
Index of Notes to Financial Statements of Registrants	182

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.

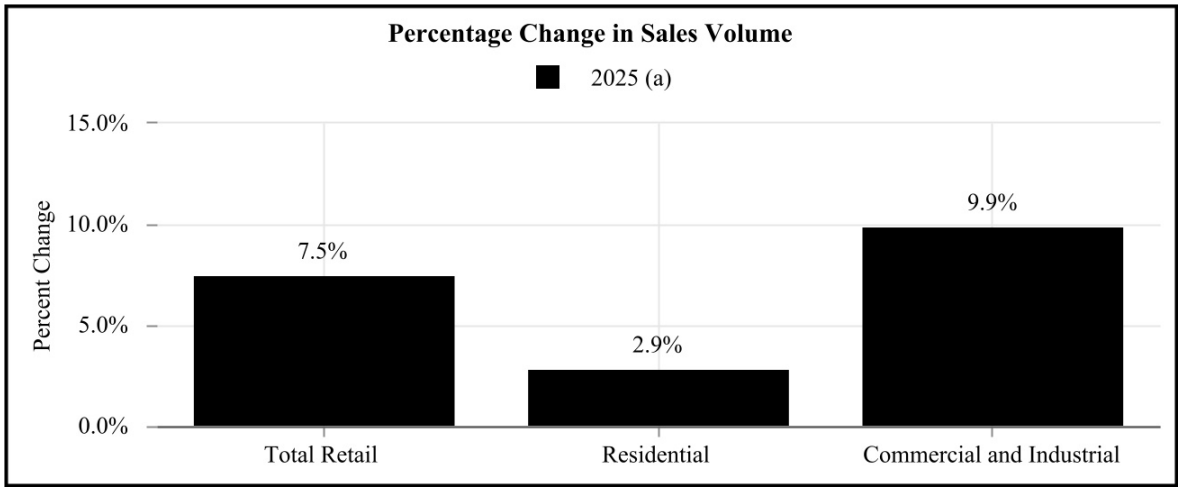
AEP has advanced large-load tariff proposals and tariff modifications aimed at enabling the rapid interconnection of committed large load customers while protecting existing customers from increased costs. These proposals have been filed in eight of AEP's jurisdictions, with four already approved by 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	Approved ROE	New Rates Effective	
		(in millions)			
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	Requested ROE
			(in millions)	
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.

AEP TRANSMISSION HOLDCO

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		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 182.

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 $0, $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 182.

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 182.

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 182.

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

(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 182.

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 182.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2025	2024	2023
	(in millions of KWhs)		
Retail:			
Residential	12,853	12,654	12,659
Commercial	19,562	15,852	13,549
Industrial	13,810	13,247	12,672
Miscellaneous	622	634	636
Total Retail	46,847	42,387	39,516

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2025	2024	2023
	(in degree days)		
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

AEP Texas Inc. and Subsidiaries
Reconciliation of Year Ended December 31, 2024 to Year Ended December 31, 2025
Net Income
(in millions)

Year Ended December 31, 2024	$	420
Changes in Revenues:		
Retail Revenues		141
Transmission Revenues		44
Other Revenues		(66)
Total Change in Revenues		119
Changes in Expenses and Other:		
Other Operation and Maintenance		(94)
Depreciation and Amortization		53
Taxes Other Than Income Taxes		(5)
Interest Income		(5)
Allowance for Equity Funds Used During Construction		7
Non-Service Cost Components of Net Periodic Benefit Cost		2
Interest Expense		(10)
Total Change in Expenses and Other		(52)
Income Tax Expense		1
Year Ended December 31, 2025	$	488

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

- **Retail Revenues** increased $141 million primarily due to a $130 million increase from base rate and rider revenues.
- **Transmission Revenues** increased $44 million due to the following:
  - A $92 million increase in interim rates driven by increased transmission investments.

  This increase was partially offset by:
  - A $48 million decrease due to lower peak loads included in 2025 billing rates.
- **Other Revenues** decreased $66 million primarily due to a $74 million decrease in securitization revenues resulting from the maturity of Transition Funding III LLC securitization bonds in December 2024.

Expenses and Other changed between years as follows:

- **Other Operation and Maintenance** expenses increased $94 million primarily due to the following:
  - A $54 million increase in recoverable Transmission Cost Recovery Factor expenses.
  - A $19 million increase in transmission and distribution expenses.
  - A $13 million increase due to an impairment of in-process internal use software development costs.
  - A $12 million increase in employee-related expenses.

  These increases were partially offset by:
  - A $20 million decrease due to the voluntary severance program that occurred in the second quarter of 2024.
- **Depreciation and Amortization** expenses decreased $53 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.
- **Taxes Other Than Income Taxes** increased $5 million primarily due to higher property taxes driven by increased investment, partially offset by the deferral of eligible costs related to the UTM.
- **Interest Income** decreased $5 million primarily due to lower interest rates on advances to affiliates.
- **Allowance for Equity Funds Used During Construction** increased $7 million primarily due to a higher AFUDC base.
- **Interest Expense** increased $10 million primarily due to the following:
  - A $36 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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
AEP Texas Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of AEP Texas 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 common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements 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.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements 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 of these consolidated financial statements 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits 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. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

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 $402 million of deferred costs included in regulatory assets, $181 million of which were pending final regulatory approval, and $1,286 million of regulatory liabilities awaiting potential refund or future rate reduction. 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.

/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 AEP Texas Inc. and Subsidiaries (AEP Texas) 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 Texas' 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 Texas' 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 Texas' internal control over financial reporting was effective as of December 31, 2025.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, AEP Texas' registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit AEP Texas to provide only management's report in this annual report.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
REVENUES			
Electric Transmission and Distribution	$ 2,187	$ 2,071	$ 1,892
Sales to AEP Affiliates	5	5	5
Other Revenues	7	4	5
TOTAL REVENUES	2,199	2,080	1,902
EXPENSES			
Other Operation	705	625	541
Maintenance	104	90	92
Depreciation and Amortization	441	494	469
Taxes Other Than Income Taxes	169	164	161
TOTAL EXPENSES	1,419	1,373	1,263
OPERATING INCOME	780	707	639
Other Income (Expense):			
Interest Income	2	7	3
Allowance for Equity Funds Used During Construction	53	46	28
Non-Service Cost Components of Net Periodic Benefit Cost	22	20	19
Interest Expense	(268)	(258)	(233)
INCOME BEFORE INCOME TAX EXPENSE	589	522	456
Income Tax Expense	101	102	86
NET INCOME	$ 488	$ 420	$ 370

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

See Notes to Financial Statements of Registrants beginning on page 182.

AEP TEXAS INC. AND SUBSIDIARIES
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	$ 488	$ 420	$ 370
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $0, $2 and $0 in 2025, 2024 and 2023, Respectively	(1)	6	1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0, $0 and $0 in 2025, 2024 and 2023, Respectively	—	—	(1)
Pension and OPEB Funded Status, Net of Tax of $0, $0 and $0 in 2025, 2024 and 2023, Respectively	1	—	—
TOTAL OTHER COMPREHENSIVE INCOME	—	6	—
TOTAL COMPREHENSIVE INCOME	$ 488	$ 426	$ 370

See Notes to Financial Statements of Registrants beginning on page 182.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	$ 1,558	$ 2,355	$ (9)	$ 3,904
Capital Contribution from Parent	527			527
Return of Capital to Parent	(5)			(5)
Net Income		370		370
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2023	2,080	2,725	(9)	4,796
Capital Contribution from Parent	14			14
Return of Capital to Parent	(1)			(1)
Common Stock Dividends		(350)		(350)
Net Income		420		420
Other Comprehensive Income			6	6
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2024	2,093	2,795	(3)	4,885
Capital Contribution from Parent	453			453
Net Income		488		488
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2025	$ 2,546	$ 3,283	$ (3)	$ 5,826

See Notes to Financial Statements of Registrants beginning on page 182.

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

	December 31, 2025	December 31, 2024
CURRENT ASSETS		
Restricted Cash (December 31, 2025 and 2024 Amounts Include $14 and $24, Respectively, Related to Transition Funding and Restoration Funding)	$ 14	$ 24
Advances to Affiliates	7	7
Accounts Receivable:		
Customers	189	183
Affiliated Companies	15	11
Accrued Unbilled Revenues	101	97
Allowance for Credit Losses	—	(4)
Total Accounts Receivable	305	287
Materials and Supplies	168	170
Prepayments and Other Current Assets	15	12
TOTAL CURRENT ASSETS	509	500
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	8,229	7,546
Distribution	6,835	6,251
Other Property, Plant and Equipment	1,239	1,175
Construction Work in Progress	1,766	1,118
Total Property, Plant and Equipment	18,069	16,090
Accumulated Depreciation and Amortization	2,205	2,046
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	15,864	14,044
OTHER NONCURRENT ASSETS		
Regulatory Assets	402	354
Securitized Assets (December 31, 2025 and 2024 Amounts Include $94 and $117, Respectively, Related to Restoration Funding)	94	117
Operating Lease Assets	52	54
Deferred Charges and Other Noncurrent Assets	154	131
TOTAL OTHER NONCURRENT ASSETS	702	656
TOTAL ASSETS	$ 17,075	$ 15,200

See Notes to Financial Statements of Registrants beginning on page 182.

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

	December 31, 2025	December 31, 2024
CURRENT LIABILITIES		
Advances from Affiliates	$ 188	$ 285
Accounts Payable:		
General	652	366
Affiliated Companies	60	35
Long-term Debt Due Within One Year – Nonaffiliated (December 31, 2025 and 2024 Amounts Include $25 and $24, Respectively, Related to Restoration Funding)	75	325
Accrued Taxes	118	127
Accrued Interest (December 31, 2025 and 2024 Amounts Include $1 and $2, Respectively, Related to Restoration Funding)	64	55
Obligations Under Operating Leases	14	13
Other Current Liabilities	247	201
TOTAL CURRENT LIABILITIES	1,418	1,407
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (December 31, 2025 and 2024 Amounts Include $78 and $102, Respectively, Related to Restoration Funding)	6,941	6,117
Deferred Income Taxes	1,430	1,323
Regulatory Liabilities and Deferred Investment Tax Credits	1,286	1,285
Obligations Under Operating Leases	40	43
Deferred Credits and Other Noncurrent Liabilities	134	140
TOTAL NONCURRENT LIABILITIES	9,831	8,908
TOTAL LIABILITIES	11,249	10,315
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Paid-in Capital	2,546	2,093
Retained Earnings	3,283	2,795
Accumulated Other Comprehensive Income (Loss)	(3)	(3)
TOTAL COMMON SHAREHOLDER'S EQUITY	5,826	4,885
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 17,075	$ 15,200

See Notes to Financial Statements of Registrants beginning on page 182.

AEP TEXAS INC. AND SUBSIDIARIES
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	$ 488	$ 420	$ 370
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	441	494	469
Deferred Income Taxes	71	78	64
Allowance for Equity Funds Used During Construction	(53)	(46)	(28)
Pension Contributions to Qualified Plan Trust	(12)	—	—
Change in Other Noncurrent Assets	(108)	(91)	(97)
Change in Other Noncurrent Liabilities	85	39	24
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(18)	(8)	(28)
Materials and Supplies	2	21	(52)
Accounts Payable	72	25	(24)
Accrued Taxes, Net	(10)	30	12
Other Current Assets	3	(6)	4
Other Current Liabilities	(41)	8	(54)
Net Cash Flows from Operating Activities	920	964	660
INVESTING ACTIVITIES			
Construction Expenditures	(1,920)	(1,414)	(1,477)
Other Investing Activities	68	55	69
Net Cash Flows Used for Investing Activities	(1,852)	(1,359)	(1,408)
FINANCING ACTIVITIES			
Capital Contribution from Parent	453	14	527
Return of Capital to Parent	—	(1)	(5)
Issuance of Long-term Debt – Nonaffiliated	1,293	842	505
Change in Advances from Affiliates, Net	(97)	181	7
Retirement of Long-term Debt – Nonaffiliated	(724)	(296)	(279)
Principal Payments for Finance Lease Obligations	(8)	(8)	(7)
Dividends Paid on Common Stock	—	(350)	—
Other Financing Activities	5	3	2
Net Cash Flows from Financing Activities	922	385	750
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(10)	(10)	2
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	24	34	32
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 14	$ 24	$ 34
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 244	$ 241	$ 226
Noncash Acquisitions Under Finance Leases	7	5	5
Construction Expenditures Included in Current Liabilities as of December 31,	514	266	112

See Notes to Financial Statements of Registrants beginning on page 182.

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of December 31, 2025	2024
	(in millions)	
Plant In Service	$ 17,113	$ 15,429
CWIP	2,005	1,965
Accumulated Depreciation	1,915	1,578
Total Transmission Property, Net	$ 17,203	$ 15,816

AEP Transmission Company, LLC and Subsidiaries
Reconciliation of Year Ended December 31, 2024 to Year Ended December 31, 2025
Earnings Attributable to AEP Member
(in millions)

Year Ended December 31, 2024	$ 688
Changes in Transmission Revenues:	
Transmission Revenues	428
Total Change in Transmission Revenues	428
Changes in Expenses and Other:	
Other Operation and Maintenance	(27)
Depreciation and Amortization	(47)
Taxes Other Than Income Taxes	(12)
Interest Income - Affiliated	(5)
Allowance for Equity Funds Used During Construction	4
Interest Expense	(20)
Total Change in Expenses and Other	(107)
Income Tax Expense	175
Net Income Attributable to Noncontrolling Interest	(109)
Year Ended December 31, 2025	$ 1,075

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

- **Transmission Revenues** increased $428 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 $214 million increase due to continued transmission investment.

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

- **Other Operation and Maintenance** expenses increased $27 million primarily due to an increase in employee-related 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 $12 million primarily due to higher property taxes driven by increased transmission investment.
- **Interest Income - Affiliated** decreased $5 million primarily due to lower advances to affiliates.
- **Interest Expense** increased $20 million primarily due to higher long-term debt balances and interest rates.

- **Income Tax Expense** decreased $175 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 $67 million increase due to an increase in pretax book income.
- **Net Income Attributable to Noncontrolling Interest** increased $109 million due to the Midwest Transmission noncontrolling interest transaction that closed in June 2025.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Member of
AEP Transmission Company, LLC

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of AEP Transmission Company, LLC and its subsidiaries (the "Company") as of December 31, 2025 and 2024, and the related consolidated statements of income, of changes in member's 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 schedule listed in the index appearing under Item 15(a)(2) (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements 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.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements 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 of these consolidated financial statements 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits 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. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

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 $73 million of deferred costs included in regulatory assets, $9 million of which were pending final regulatory approval, and $708 million of regulatory liabilities awaiting potential refund or future rate reduction. 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.

/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 AEP Transmission Company, LLC and Subsidiaries (AEPTCo) 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. AEPTCo'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 AEPTCo'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 AEPTCo's internal control over financial reporting was effective as of December 31, 2025.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, AEPTCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit AEPTCo to provide only management's report in this annual report.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Years Ended December 31,		
	2025	2024	2023
REVENUES			
Transmission Revenues	$ 428	$ 401	$ 363
Sales to AEP Affiliates	1,790	1,582	1,463
(Provision for)/Reversal of – Revenue Refund – Affiliated	79	(70)	(146)
(Provision for)/ Reversal of – Revenue Refund – Nonaffiliated	22	(22)	(9)
TOTAL REVENUES	2,319	1,891	1,671
EXPENSES			
Other Operation	154	137	109
Maintenance	31	21	20
Depreciation and Amortization	478	431	394
Taxes Other Than Income Taxes	321	309	283
TOTAL EXPENSES	984	898	806
OPERATING INCOME	1,335	993	865
Other Income (Expense):			
Interest Income - Affiliated	5	10	8
Allowance for Equity Funds Used During Construction	93	89	83
Interest Expense	(234)	(214)	(195)
INCOME BEFORE INCOME TAX EXPENSE	1,199	878	761
Income Tax Expense	15	190	147
NET INCOME	1,184	688	614
Net Income Attributable to Noncontrolling Interest	109	—	—
EARNINGS ATTRIBUTABLE TO AEP MEMBER	$ 1,075	$ 688	$ 614

AEPTCo is wholly-owned by AEP Transmission Holdco.

See Notes to Financial Statements of Registrants beginning on page 182.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Paid-in Capital	Retained Earnings	Noncontrolling Interest	Total Member's Equity
TOTAL MEMBER'S EQUITY - DECEMBER 31, 2022	$ 3,022	$ 2,851	$ —	$ 5,873
Capital Contribution from AEP Member	30			30
Return of Capital to AEP Member	(8)			(8)
Dividends Paid to AEP Member		(175)		(175)
Net Income		614		614
TOTAL MEMBER'S EQUITY - DECEMBER 31, 2023	3,044	3,290	—	6,334
Capital Contribution from AEP Member	62			62
Return of Capital to AEP Member	(5)			(5)
Dividends Paid to AEP Member		(128)		(128)
Net Income		688		688
TOTAL MEMBER'S EQUITY - DECEMBER 31, 2024	3,101	3,850	—	6,951
Capital Contribution from AEP Member	70			70
Capital Contribution from Noncontrolling Interest			34	34
Dividends Paid to AEP Member		(3,274)		(3,274)
Dividends Paid to Noncontrolling Interest			(105)	(105)
Midwest Transmission Holdings Noncontrolling Interest Transaction	1,791		992	2,783
Net Income		1,075	109	1,184
TOTAL MEMBER'S EQUITY - DECEMBER 31, 2025	$ 4,962	$ 1,651	$ 1,030	$ 7,643

See Notes to Financial Statements of Registrants beginning on page 182.

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

	December 31, 2025	December 31, 2024
CURRENT ASSETS		
Advances to Affiliates	$ 71	$ 30
Accounts Receivable:		
Customers	94	59
Affiliated Companies	153	134
Miscellaneous	—	1
Total Accounts Receivable	247	194
Prepayments and Other Current Assets	4	12
TOTAL CURRENT ASSETS	322	236
TRANSMISSION PROPERTY		
Transmission Property	16,542	14,913
Other Property, Plant and Equipment	571	516
Construction Work in Progress	2,005	1,965
Total Transmission Property	19,118	17,394
Accumulated Depreciation and Amortization	1,915	1,578
TOTAL TRANSMISSION PROPERTY – NET	17,203	15,816
OTHER NONCURRENT ASSETS		
Regulatory Assets	73	—
Deferred Property Taxes	326	309
Deferred Charges and Other Noncurrent Assets	75	9
TOTAL OTHER NONCURRENT ASSETS	474	318
TOTAL ASSETS	$ 17,999	$ 16,370

See Notes to Financial Statements of Registrants beginning on page 182.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
December 31, 2025 and 2024

	December 31, 2025	2024
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 143	$ 85
Accounts Payable:		
General	477	360
Affiliated Companies	164	117
Long-term Debt Due Within One Year – Nonaffiliated	425	90
Accrued Taxes	650	666
Accrued Interest	46	45
Obligations Under Operating Leases	1	1
Other Current Liabilities	41	45
TOTAL CURRENT LIABILITIES	1,947	1,409
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	6,174	5,678
Deferred Income Taxes	1,481	1,279
Regulatory Liabilities	708	878
Obligations Under Operating Leases	2	1
Deferred Credits and Other Noncurrent Liabilities	44	174
TOTAL NONCURRENT LIABILITIES	8,409	8,010
TOTAL LIABILITIES	10,356	9,419
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
MEMBER'S EQUITY		
Paid-in Capital	4,962	3,101
Retained Earnings	1,651	3,850
TOTAL MEMBER'S EQUITY	6,613	6,951
Noncontrolling Interest	1,030	—
TOTAL EQUITY	7,643	6,951
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 17,999	$ 16,370

See Notes to Financial Statements of Registrants beginning on page 182.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
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	$ 1,184	$ 688	$ 614
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	478	431	394
Deferred Income Taxes	(152)	110	44
Allowance for Equity Funds Used During Construction	(93)	(89)	(83)
Property Taxes	(17)	(22)	(20)
Change in Other Noncurrent Assets	(80)	(1)	8
Change in Other Noncurrent Liabilities	(127)	(17)	134
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(53)	13	(41)
Materials and Supplies	—	—	11
Accounts Payable	75	10	23
Accrued Taxes, Net	(16)	97	43
Accrued Interest	1	5	11
Other Current Assets	7	(1)	—
Other Current Liabilities	(22)	14	—
Net Cash Flows from Operating Activities	1,185	1,238	1,138
INVESTING ACTIVITIES			
Construction Expenditures	(1,569)	(1,477)	(1,496)
Change in Advances to Affiliates, Net	(41)	37	(63)
Acquisitions of Assets	(10)	(5)	(7)
Other Investing Activities	42	17	7
Net Cash Flows Used for Investing Activities	(1,578)	(1,428)	(1,559)
FINANCING ACTIVITIES			
Capital Contribution from AEP Member	70	62	30
Capital Contribution from Noncontrolling Interest	34	—	—
Return of Capital to AEP Member	—	(5)	(8)
Issuance of Long-term Debt – Nonaffiliated	929	446	689
Retirement of Long-term Debt – Nonaffiliated	(102)	(95)	(60)
Change in Advances from Affiliates, Net	58	(90)	(55)
Proceeds from the Midwest Transmission Holdings Noncontrolling Interest Transaction, Net of Transaction Costs	2,783	—	—
Dividends Paid to AEP Member	(3,274)	(128)	(175)
Dividends Paid to Noncontrolling Interest	(105)	—	—
Net Cash Flows from Financing Activities	393	190	421
Net Change in Cash and Cash Equivalents	—	—	—
Cash and Cash Equivalents at Beginning of Period	—	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —	$ —
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 227	$ 204	$ 180
Construction Expenditures Included in Current Liabilities as of December 31,	343	263	178

See Notes to Financial Statements of Registrants beginning on page 182.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2025	**2024**	**2023**
		(in millions of KWhs)	
Retail:			
Residential	10,909	10,483	10,126
Commercial	5,975	5,948	5,728
Industrial	8,565	8,666	8,710
Miscellaneous	835	829	804
Total Retail	26,284	25,926	25,368
Wholesale (a)	3,058	2,243	2,191
Total KWhs	29,342	28,169	27,559

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

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2025	**2024**	**2023**
		(in degree days)	
Actual – Heating	2,257	1,713	1,537
Normal – Heating	2,134	2,181	2,208
Actual – Cooling	1,186	1,544	1,145
Normal – Cooling	1,241	1,250	1,251

Appalachian Power Company and Subsidiaries
Reconciliation of Year Ended December 31, 2024 to Year Ended December 31, 2025
Net Income
(in millions)

Year Ended December 31, 2024	$	422
Changes in Revenues:		
Retail Revenues		140
Off-system Sales		7
Transmission Revenues		23
Other Revenues		6
Total Change in Revenues		176
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation		8
Other Operation and Maintenance		(95)
Depreciation and Amortization		(30)
Taxes Other Than Income Taxes		5
Interest Income		(1)
Allowance for Equity Funds Used During Construction		1
Non-Service Cost Components of Net Periodic Benefit Cost		(6)
Interest Expense		(12)
Total Change in Expenses and Other		(130)
Income Tax Expense		(11)
Year Ended December 31, 2025	$	457

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

- **Retail Revenues** increased $140 million primarily due to the following:
  - A $57 million increase in base rate and rider revenues.
  - A $50 million increase in fuel revenues.
  - A $30 million increase in weather-related usage driven by a 32% increase in heating degree days, partially offset by a 23% decrease in cooling degree days.
  - A $6 million increase in weather-normalized revenues primarily in the residential and commercial classes.
- **Off-system Sales** increased $7 million primarily due to capacity revenues recognized from the RPM auction for the 2025-2026 planning year.
- **Transmission Revenues** increased $23 million primarily due to the following:
  - An $18 million increase due to continued transmission investment.
  - A $6 million increase due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- **Other Revenues** increased $6 million primarily due to increased rent received from associated companies.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $8 million primarily to the following:
  - An $18 million decrease due to the prior year amortization of Excess ADIT through the West Virginia ENEC.
  - A $17 million decrease due to the impact to the West Virginia ENEC as a result of the June 2025 FERC NOLC order.

  These decreases were partially offset by:
  - A $27 million increase in purchased power prices and renewable energy credit revenue.
- **Other Operation and Maintenance** expenses increased $95 million primarily due to the following:
  - A $42 million increase in transmission expenses primarily due to:
    - An $18 million increase in recoverable PJM expenses.
    - A $15 million increase due to the June 2025 FERC NOLC order.
  - A $27 million increase in distribution expenses primarily due to an increase in storm-related expenses, partially offset by a decrease in vegetation management costs.

- A $21 million increase due to recoverable energy assistance program expenses for qualified Virginia customers.
- A $13 million increase in employee-related expenses.
- An $11 million increase due to an impairment of in-process internal use software development costs.

These increases were partially offset by:

- A $26 million decrease due to the voluntary severance program that occurred in the second quarter of 2024.

- **Depreciation and Amortization** expenses increased $30 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** decreased $5 million primarily due to lower business and occupation taxes, partially offset by higher property taxes.
- **Non-Service Cost Components of Net Periodic Benefit Cost** increased $6 million primarily due to lower asset returns in prior years and a higher cash balance interest crediting rate, partially offset by an increase in the discount rate.
- **Interest Expense** increased $12 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $11 million primarily due to the following:
  - An $18 million increase due to an increase in flow-through CAMT expense.
  - A $14 million increase due to a decrease in amortization of Excess ADIT.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Appalachian Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Appalachian Power Company 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 common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements 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.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements 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 of these consolidated financial statements 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits 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. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

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 $1,522 million of deferred costs included in regulatory assets, $440 million of which were pending final regulatory approval, and $1,111 million of regulatory liabilities awaiting potential refund or future rate reduction. 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.

/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 Appalachian Power Company and Subsidiaries (APCo) 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. APCo'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 APCo'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 APCo's internal control over financial reporting was effective as of December 31, 2025.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, APCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit APCo to provide only management's report in this annual report.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Years Ended December 31,		
	2025	2024	2023
REVENUES			
Electric Generation, Transmission and Distribution	$ 3,912	$ 3,769	$ 3,464
Sales to AEP Affiliates	279	248	239
Other Revenues	18	16	18
TOTAL REVENUES	4,209	4,033	3,721
EXPENSES			
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1,398	1,406	1,435
Other Operation	867	805	748
Maintenance	356	323	272
Depreciation and Amortization	632	602	572
Taxes Other Than Income Taxes	172	177	163
TOTAL EXPENSES	3,425	3,313	3,190
OPERATING INCOME	784	720	531
Other Income (Expense):			
Interest Income	4	5	3
Allowance for Equity Funds Used During Construction	17	16	12
Non-Service Cost Components of Net Periodic Benefit Cost	21	27	32
Interest Expense	(283)	(271)	(270)
INCOME BEFORE INCOME TAX EXPENSE	543	497	308
Income Tax Expense	86	75	14
NET INCOME	$ 457	$ 422	$ 294

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

See Notes to Financial Statements of Registrants beginning on page 182.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
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	$ 457	$ 422	$ 294
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $0, $0 and $0 in 2025, 2024 and 2023, Respectively	(1)	(1)	(1)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0, $0 and $(1) in 2025, 2024 and 2023, Respectively	—	(1)	(3)
Pension and OPEB Funded Status, Net of Tax of $4, $5 and $1 in 2025, 2024 and 2023, Respectively	14	17	5
TOTAL OTHER COMPREHENSIVE INCOME	13	15	1
TOTAL COMPREHENSIVE INCOME	$ 470	$ 437	$ 295

See Notes to Financial Statements of Registrants beginning on page 182.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	$ 260	$ 1,829	$ 2,891	$ (5)	$ 4,975
Capital Contribution from Parent		7			7
Return of Capital to Parent		(1)			(1)
Net Income			294		294
Other Comprehensive Income				1	1
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2023	260	1,835	3,185	(4)	5,276
Capital Contribution from Parent		114			114
Return of Capital to Parent		(4)			(4)
Common Stock Dividends			(75)		(75)
Net Income			422		422
Other Comprehensive Income				15	15
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2024	260	1,945	3,532	11	5,748
Capital Contribution from Parent		12			12
Common Stock Dividends			(50)		(50)
Net Income			457		457
Other Comprehensive Income				13	13
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2025	$ 260	$ 1,957	$ 3,939	$ 24	$ 6,180

See Notes to Financial Statements of Registrants beginning on page 182.

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

	December 31, 2025	December 31, 2024
CURRENT ASSETS		
Cash and Cash Equivalents	$ 5	$ 4
Restricted Cash for Securitized Funding	18	16
Advances to Affiliates	17	18
Accounts Receivable:		
Customers	171	186
Affiliated Companies	142	110
Accrued Unbilled Revenues	112	93
Allowance for Credit Losses	(2)	(2)
Total Accounts Receivable	423	387
Fuel	229	308
Materials and Supplies	139	132
Risk Management Assets	81	36
Regulatory Asset for Under-Recovered Fuel Costs	83	148
Prepayments and Other Current Assets	38	46
TOTAL CURRENT ASSETS	1,033	1,095
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	7,886	7,273
Transmission	5,277	5,001
Distribution	5,938	5,569
Other Property, Plant and Equipment	1,175	1,063
Construction Work in Progress	802	743
Total Property, Plant and Equipment	21,078	19,649
Accumulated Depreciation and Amortization	6,365	6,036
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	14,713	13,613
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,439	1,366
Securitized Assets	78	106
Employee Benefits and Pension Assets	251	204
Operating Lease Assets	95	67
Deferred Charges and Other Noncurrent Assets	183	215
TOTAL OTHER NONCURRENT ASSETS	2,046	1,958
TOTAL ASSETS	$ 17,792	$ 16,666

See Notes to Financial Statements of Registrants beginning on page 182.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2025 and 2024

	December 31, 2025	2024
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 209	$ 95
Accounts Payable:		
General	375	427
Affiliated Companies	173	206
Long-term Debt Due Within One Year - Nonaffiliated	1,131	799
Customer Deposits	94	87
Accrued Taxes	116	169
Obligations Under Operating Leases	15	14
Other Current Liabilities	271	229
TOTAL CURRENT LIABILITIES	2,384	2,026
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	5,128	4,862
Deferred Income Taxes	2,130	2,034
Regulatory Liabilities and Deferred Investment Tax Credits	1,111	1,116
Asset Retirement Obligations	707	767
Employee Benefits and Pension Obligations	26	30
Obligations Under Operating Leases	81	54
Deferred Credits and Other Noncurrent Liabilities	45	29
TOTAL NONCURRENT LIABILITIES	9,228	8,892
TOTAL LIABILITIES	11,612	10,918
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260	260
Paid-in Capital	1,957	1,945
Retained Earnings	3,939	3,532
Accumulated Other Comprehensive Income (Loss)	24	11
TOTAL COMMON SHAREHOLDER'S EQUITY	6,180	5,748
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 17,792	$ 16,666

See Notes to Financial Statements of Registrants beginning on page 182.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
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	$ 457	$ 422	$ 294
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	632	602	572
Deferred Income Taxes	42	(17)	(54)
Allowance for Equity Funds Used During Construction	(17)	(16)	(12)
Mark-to-Market of Risk Management Contracts	(44)	(35)	66
Deferred Fuel Over/Under-Recovery, Net	59	136	280
Change in Regulatory Assets	(155)	(115)	(20)
Change in Other Noncurrent Assets	(17)	(47)	(95)
Change in Other Noncurrent Liabilities	54	12	(2)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(36)	(46)	18
Fuel, Materials and Supplies	72	24	(174)
Accounts Payable	(62)	166	(126)
Accrued Taxes, Net	(59)	51	25
Other Current Assets	16	(4)	(16)
Other Current Liabilities	(20)	11	(33)
Net Cash Flows from Operating Activities	922	1,144	723
INVESTING ACTIVITIES			
Construction Expenditures	(1,056)	(1,009)	(1,053)
Change in Advances to Affiliates, Net	1	1	1
Acquisitions of Assets	(548)	(1)	(11)
Other Investing Activities	19	16	8
Net Cash Flows Used for Investing Activities	(1,584)	(993)	(1,055)
FINANCING ACTIVITIES			
Capital Contribution from Parent	12	114	7
Return of Capital to Parent	—	(4)	(1)
Issuance of Long-term Debt – Nonaffiliated	1,143	481	200
Change in Advances from Affiliates, Net	114	(245)	157
Retirement of Long-term Debt – Nonaffiliated	(548)	(414)	(27)
Principal Payments for Finance Lease Obligations	(9)	(9)	(8)
Dividends Paid on Common Stock	(50)	(75)	—
Other Financing Activities	3	1	2
Net Cash Flows from (Used for) Financing Activities	665	(151)	330
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	3	—	(2)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	20	20	22
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 23	$ 20	$ 20
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 272	$ 257	$ 260
Noncash Acquisitions Under Finance Leases	4	2	5
Construction Expenditures Included in Current Liabilities as of December 31,	143	159	101

See Notes to Financial Statements of Registrants beginning on page 182.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2025	**2024**	**2023**
	(in millions of KWhs)		
Retail:			
Residential	5,473	5,301	5,169
Commercial	6,571	5,273	4,971
Industrial	7,218	7,298	7,309
Miscellaneous	46	49	55
Total Retail	19,308	17,921	17,504
Wholesale (a)	6,381	6,278	5,215
Total KWhs	25,689	24,199	22,719

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

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2025	**2024**	**2023**
	(in degree days)		
Actual – Heating	3,713	2,859	2,917
Normal – Heating	3,642	3,721	3,734
Actual – Cooling	927	987	751
Normal – Cooling	883	867	871

Indiana Michigan Power Company and Subsidiaries
Reconciliation of Year Ended December 31, 2024 to Year Ended December 31, 2025
Net Income
(in millions)

Year Ended December 31, 2024	$	391
Changes in Revenues:		
Retail Revenues		315
Off-system Sales		137
Transmission Revenues		9
Other Revenues		(2)
Total Change in Revenues		459
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation		(184)
Purchased Electricity from AEP Affiliates		(61)
Other Operation and Maintenance		(58)
Asset Impairments and Other Related Charges		6
Depreciation and Amortization		(33)
Taxes Other Than Income Taxes		(3)
Other Income		8
Non-Service Cost Components of Net Periodic Benefit Cost		2
Interest Expense		(17)
Total Change in Expenses and Other		(340)
Income Tax Expense		(96)
Year Ended December 31, 2025	$	414

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

- **Retail Revenues** increased $315 million primarily due to the following:
  - A $109 million increase in rider revenues.
  - A $100 million increase in weather-normalized revenues primarily in the commercial class.
  - An $89 million increase due to the implementation of new base rates in Indiana and Michigan.
  - A $76 million increase in fuel revenues.
  - A $23 million increase in weather-related usage primarily due to a 30% increase in heating degree days.

  These increases were partially offset by:
  - An $86 million decrease due to regulatory provisions for refund.
- **Off-system Sales** increased $137 million primarily due to economic hedging activity and Rockport Plant, Unit 2 merchant sales.
- **Transmission Revenues** increased $9 million primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $184 million primarily due to an increase in recoverable fuel and purchased power costs and an increase in Rockport Plant, Unit 2, merchant generation fuel costs.
- **Purchased Electricity from AEP Affiliates** increased $61 million primarily due to an increase in purchased electricity from AEGCo.

- **Other Operation and Maintenance** expenses increased $58 million primarily due to the following:
  - A $38 million increase in distribution expenses primarily due to an increase in vegetation management costs and other distribution-related expenses.
  - A $20 million increase in transmission expenses primarily due to a $25 million increase in recoverable PJM expenses, partially offset by a $6 million decrease due to the June 2025 FERC order related to the treatment of stand-alone NOLCs in transmission formula rates.
  - An $18 million increase in employee-related expenses.
  - A $14 million increase in nuclear expenses at Cook Plant.

  These increases were partially offset by:
  - A $15 million decrease due to the voluntary severance program that occurred in the second quarter of 2024.
  - A $13 million decrease in demand side management expenses.
  - An $11 million decrease in non-utility operation expenses due to a decrease in River Transportation Division barging expenses.
- **Asset Impairments and Other Related Charges** decreased $6 million due to the following:
  - A $13 million decrease due to the Federal EPA's revised CCR rules finalized in 2024.

  This decrease was partially offset by:
  - A $7 million increase due to an impairment of in-process internal use software development costs.
- **Depreciation and Amortization** expenses increased $33 million primarily due to the following:
  - A $20 million increase 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 $15 million increase due to a higher depreciable base.
- **Other Income** increased $8 million primarily due to an increase in AFUDC due to a higher AFUDC base and an increase in equity rates.
- **Interest Expense** increased $17 million primarily 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.
- **Income Tax Expense** increased $96 million primarily due to the following:
  - A $55 million increase due to a reduction in Excess ADIT regulatory liabilities as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail ratemaking recorded in 2024.
  - A $25 million increase due to an increase in pretax book income.
  - An $18 million increase due to a decrease in amortization of Excess ADIT.
  - A $16 million increase due to a decrease in PTCs.
  - A $9 million increase due to an increase in state taxes.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Indiana Michigan Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company 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 common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements 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.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements 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 of these consolidated financial statements 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits 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. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

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 $585 million of deferred costs included in regulatory assets, $118 million of which were pending final regulatory approval, and $2,957 million of regulatory liabilities awaiting potential refund or future rate reduction, $27 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.

/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 Indiana Michigan Power Company and Subsidiaries (I&M) 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. I&M'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 I&M'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 I&M's internal control over financial reporting was effective as of December 31, 2025.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, I&M's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit I&M to provide only management's report in this annual report.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
REVENUES			
Electric Generation, Transmission and Distribution	$ 3,096	$ 2,552	$ 2,469
Sales to AEP Affiliates	14	15	9
Provision for Revenue Refund – Affiliated	(3)	(14)	(11)
Provision for Revenue Refund – Nonaffiliated	(142)	(57)	(3)
Other Revenues – Affiliated	58	65	59
Other Revenues – Nonaffiliated	8	11	13
TOTAL REVENUES	3,031	2,572	2,536
EXPENSES			
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	601	417	411
Purchased Electricity from AEP Affiliates	270	209	181
Other Operation	731	729	663
Maintenance	291	235	239
Asset Impairment and Other Related Charges	7	13	—
Depreciation and Amortization	514	481	470
Taxes Other Than Income Taxes	92	89	84
TOTAL EXPENSES	2,506	2,173	2,048
OPERATING INCOME	525	399	488
Other Income (Expense):			
Other Income	21	13	13
Non-Service Cost Components of Net Periodic Benefit Cost	20	18	31
Interest Expense	(151)	(134)	(137)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	415	296	395
Income Tax Expense (Benefit)	1	(95)	59
NET INCOME	$ 414	$ 391	$ 336

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

See Notes to Financial Statements of Registrants beginning on page 182.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
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	$ 414	$ 391	$ 336
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0, $0 and $0 in 2025, 2024 and 2023, Respectively	—	—	(1)
Pension and OPEB Funded Status, Net of Tax of $0, $0 and $0 in 2025, 2024 and 2023, Respectively	2	1	1
TOTAL OTHER COMPREHENSIVE INCOME	2	1	—
TOTAL COMPREHENSIVE INCOME	$ 416	$ 392	$ 336

See Notes to Financial Statements of Registrants beginning on page 182.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	$ 57	$ 989	$ 1,963	$ (1)	$ 3,008
Capital Contribution from Parent		9			9
Common Stock Dividends			(212)		(212)
Net Income			336		336
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2023	57	998	2,087	(1)	3,141
Capital Contribution from Parent		16			16
Return of Capital to Parent		(2)			(2)
Common Stock Dividends			(150)		(150)
Net Income			391		391
Other Comprehensive Income				1	1
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2024	57	1,012	2,328	—	3,397
Capital Contribution from Parent		21			21
Common Stock Dividends			(50)		(50)
Net Income			414		414
Other Comprehensive Income				2	2
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2025	$ 57	$ 1,033	$ 2,692	$ 2	$ 3,784

See Notes to Financial Statements of Registrants beginning on page 182.

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

	December 31, 2025	December 31, 2024
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2	$ 2
Advances to Affiliates	192	—
Accounts Receivable:		
Customers	103	59
Affiliated Companies	90	79
Accrued Unbilled Revenues	17	21
Miscellaneous	2	6
Total Accounts Receivable	212	165
Fuel	61	83
Materials and Supplies	222	212
Risk Management Assets	10	18
Regulatory Asset for Under-Recovered Fuel Costs	—	11
Prepayments and Other Current Assets	85	53
TOTAL CURRENT ASSETS	784	544
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,483	5,503
Transmission	2,055	1,958
Distribution	3,823	3,535
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	1,058	992
Construction Work in Progress	403	335
Total Property, Plant and Equipment	12,822	12,323
Accumulated Depreciation, Depletion and Amortization	4,878	4,644
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,944	7,679
OTHER NONCURRENT ASSETS		
Regulatory Assets	585	548
Spent Nuclear Fuel and Decommissioning Trusts	4,916	4,395
Operating Lease Assets	52	52
Deferred Charges and Other Noncurrent Assets	344	318
TOTAL OTHER NONCURRENT ASSETS	5,897	5,313
TOTAL ASSETS	$ 14,625	$ 13,536

See Notes to Financial Statements of Registrants beginning on page 182.

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

	December 31, 2025	December 31, 2024
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 127
Accounts Payable:		
General	232	202
Affiliated Companies	125	99
Long-term Debt Due Within One Year – Nonaffiliated (December 31, 2025 and 2024 Amounts Include $117 and $79, Respectively, Related to DCC Fuel)	117	269
Customer Deposits	55	59
Accrued Taxes	112	102
Accrued Interest	42	41
Obligations Under Operating Leases	17	12
Regulatory Liability for Over-Recovered Fuel Costs	19	10
Other Current Liabilities	230	150
TOTAL CURRENT LIABILITIES	949	1,071
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,444	3,225
Deferred Income Taxes	1,219	1,176
Regulatory Liabilities and Deferred Investment Tax Credits	2,938	2,481
Asset Retirement Obligations	2,165	2,089
Obligations Under Operating Leases	37	40
Deferred Credits and Other Noncurrent Liabilities	89	57
TOTAL NONCURRENT LIABILITIES	9,892	9,068
TOTAL LIABILITIES	10,841	10,139
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	57	57
Paid-in Capital	1,033	1,012
Retained Earnings	2,692	2,328
Accumulated Other Comprehensive Income (Loss)	2	—
TOTAL COMMON SHAREHOLDER'S EQUITY	3,784	3,397
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 14,625	$ 13,536

See Notes to Financial Statements of Registrants beginning on page 182.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
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	$ 414	$ 391	$ 336
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	514	481	470
Deferred Income Taxes	(13)	(117)	(54)
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(39)	13	26
Asset Impairment and Other Related Charges	7	13	—
Allowance for Equity Funds Used During Construction	(18)	(13)	(11)
Mark-to-Market of Risk Management Contracts	8	20	(22)
Amortization of Nuclear Fuel	109	103	97
Deferred Fuel Over/Under-Recovery, Net	20	(9)	56
Change in Other Noncurrent Assets	(59)	(17)	(81)
Change in Other Noncurrent Liabilities	98	41	47
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(47)	(23)	71
Fuel, Materials and Supplies	12	1	(61)
Accounts Payable	57	(45)	23
Accrued Taxes, Net	(22)	(3)	2
Other Current Assets	10	2	(6)
Other Current Liabilities	45	32	(13)
Net Cash Flows from Operating Activities	1,096	870	880
INVESTING ACTIVITIES			
Construction Expenditures	(646)	(583)	(550)
Change in Advances to Affiliates, Net	(192)	—	23
Purchases of Investment Securities	(2,959)	(2,902)	(2,845)
Sales of Investment Securities	2,909	2,851	2,788
Acquisitions of Nuclear Fuel	(130)	(140)	(128)
Other Investing Activities	33	6	5
Net Cash Flows Used for Investing Activities	(985)	(768)	(707)
FINANCING ACTIVITIES			
Capital Contribution from Parent	21	16	9
Return of Capital to Parent	—	(2)	—
Issuance of Long-term Debt - Nonaffiliated	351	80	565
Change in Advances from Affiliates, Net	(127)	64	(187)
Retirement of Long-term Debt - Nonaffiliated	(300)	(103)	(343)
Principal Payments for Finance Lease Obligations	(6)	(7)	(7)
Dividends Paid on Common Stock	(50)	(150)	(212)
Net Cash Flows Used for Financing Activities	(111)	(102)	(175)
Net Decrease in Cash and Cash Equivalents	—	—	(2)
Cash and Cash Equivalents at Beginning of Period	2	2	4
Cash and Cash Equivalents at End of Period	$ 2	$ 2	$ 2
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 145	$ 144	$ 132
Noncash Acquisitions Under Finance Leases	2	2	5
Construction Expenditures Included in Current Liabilities as of December 31,	94	77	68
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	10	24	24

See Notes to Financial Statements of Registrants beginning on page 182.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2025	**2024**	**2023**
		(in millions of KWhs)	
Retail:			
Residential	14,584	14,128	13,440
Commercial	26,625	20,295	16,870
Industrial	14,210	14,121	13,899
Miscellaneous	106	108	109
Total Retail (a)	55,525	48,652	44,318
Wholesale (b)	2,250	2,014	1,922
Total KWhs	57,775	50,666	46,240

(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

	Years Ended December 31,		
	2025	**2024**	**2023**
		(in degree days)	
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

Ohio Power Company and Subsidiaries
Reconciliation of Year Ended December 31, 2024 to Year Ended December 31, 2025
Net Income
(in millions)

Year Ended December 31, 2024	$	306
Changes in Revenues:		
Retail Revenues		54
Off-system Sales		56
Transmission Revenues		28
Other Revenues		(18)
Total Change in Revenues		120
Changes in Expenses and Other:		
Purchased Electricity for Resale		(67)
Purchased Electricity from AEP Affiliates		33
Other Operation and Maintenance		(66)
Asset Impairments and Other Related Charges		35
Depreciation and Amortization		6
Taxes Other Than Income Taxes		(14)
Other Income		(2)
Allowance for Equity Funds Used During Construction		2
Non-Service Cost Components of Net Periodic Benefit Cost		2
Interest Expense		(10)
Total Change in Expenses and Other		(81)
Income Tax Expense		(20)
Equity Earnings of Unconsolidated Subsidiaries		3
Year Ended December 31, 2025	$	328

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

- **Retail Revenues** increased $54 million primarily due to the following:
  - A $41 million increase in rider revenues.
  - A $26 million increase in weather-related usage driven by a 34% increase in heating degree days.

  These increases were partially offset by:
  - A $14 million decrease in weather-normalized revenues primarily in the residential class.
- **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 $28 million primarily due to continued transmission investment.
- **Other Revenues** decreased $18 million primarily 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.
  - 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.
- **Other Operation and Maintenance** expenses increased $66 million primarily due to the following:
  - A $105 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.
  - A $10 million increase in employee-related expenses.

  These increases were partially offset by:
  - A $29 million decrease related to recoverable energy assistance program expenses for qualified Ohio customers.
  - A $15 million decrease due to the voluntary severance program that occurred in the second quarter of 2024.

- **Asset Impairments and Other Related Charges** decreased $35 million primarily 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:
  - An $18 million increase due to an impairment of in-process internal use software development costs in 2025.
- **Depreciation and Amortization** expenses decreased $6 million primarily due to capital rider under-recoveries.
- **Taxes Other Than Income Taxes** increased $14 million primarily due to higher property taxes.
- **Interest Expense** increased $10 million primarily due to higher debt balances.
- **Income Tax Expense** increased $20 million primarily due to a decrease in amortization of Excess ADIT.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Ohio Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Ohio Power Company and its subsidiaries (the "Company") as of December 31, 2025 and 2024, and the related consolidated statements of income, of changes in common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements 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.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements 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 of these consolidated financial statements 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits 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. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

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 $326 million of deferred costs included in regulatory assets and $893 million of regulatory liabilities awaiting potential refund or future rate reduction, $77 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.

/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 Ohio Power Company and Subsidiaries (OPCo) 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. OPCo'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 OPCo'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 OPCo's internal control over financial reporting was effective as of December 31, 2025.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, OPCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit OPCo to provide only management's report in this annual report.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
REVENUES			
Electricity, Transmission and Distribution	$ 3,891	$ 3,793	$ 3,768
Sales to AEP Affiliates	45	23	31
Other Revenues	12	12	12
TOTAL REVENUES	3,948	3,828	3,811
EXPENSES			
Purchased Electricity for Resale	878	811	1,128
Purchased Electricity from AEP Affiliates	65	98	87
Other Operation	1,267	1,198	1,092
Maintenance	253	256	212
Asset Impairments and Other Related Charges	18	53	—
Depreciation and Amortization	380	386	316
Taxes Other Than Income Taxes	574	560	507
TOTAL EXPENSES	3,435	3,362	3,342
OPERATING INCOME	513	466	469
Other Income (Expense):			
Other Income	1	3	1
Allowance for Equity Funds Used During Construction	25	23	17
Non-Service Cost Components of Net Periodic Benefit Cost	17	15	26
Interest Expense	(158)	(148)	(131)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS (LOSS)	398	359	382
Income Tax Expense	72	52	54
Equity Earnings (Loss) of Unconsolidated Subsidiaries	2	(1)	—
NET INCOME	$ 328	$ 306	$ 328

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

See Notes to Financial Statements of Registrants beginning on page 182.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	$ 321	$ 838	$ 1,929	$ 3,088
Capital Contribution from Parent		175		175
Common Stock Dividends			(20)	(20)
Net Income			328	328
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2023	321	1,013	2,237	3,571
Capital Contribution from Parent		7		7
Net Income			306	306
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2024	321	1,020	2,543	3,884
Capital Contribution from Parent		10		10
Common Stock Dividends			(71)	(71)
Net Income			328	328
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2025	$ 321	$ 1,030	$ 2,800	$ 4,151

See Notes to Financial Statements of Registrants beginning on page 182.

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

	December 31, 2025	December 31, 2024
CURRENT ASSETS		
Cash and Cash Equivalents	$ 5	$ 5
Advances to Affiliates	—	115
Accounts Receivable:		
Customers	109	189
Affiliated Companies	132	118
Accrued Unbilled Revenues	29	31
Miscellaneous	—	9
Total Accounts Receivable	270	347
Materials and Supplies	191	141
Prepayments and Other Current Assets	25	20
TOTAL CURRENT ASSETS	491	628
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	3,916	3,664
Distribution	7,661	7,244
Other Property, Plant and Equipment	1,289	1,256
Construction Work in Progress	811	691
Total Property, Plant and Equipment	13,677	12,855
Accumulated Depreciation and Amortization	2,993	2,884
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,684	9,971
OTHER NONCURRENT ASSETS		
Regulatory Assets	326	379
Operating Lease Assets	50	60
Deferred Charges and Other Noncurrent Assets	659	661
TOTAL OTHER NONCURRENT ASSETS	1,035	1,100
TOTAL ASSETS	$ 12,210	$ 11,699

See Notes to Financial Statements of Registrants beginning on page 182.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2025 and 2024
(dollars in millions)

	December 31, 2025	December 31, 2024
CURRENT LIABILITIES		
Advances from Affiliates	$ 79	$ —
Accounts Payable:		
General	391	344
Affiliated Companies	197	205
Risk Management Liabilities	5	7
Customer Deposits	108	108
Accrued Taxes	858	836
Obligations Under Operating Leases	13	12
Other Current Liabilities	239	183
TOTAL CURRENT LIABILITIES	1,890	1,695
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,718	3,716
Long-term Risk Management Liabilities	28	40
Deferred Income Taxes	1,268	1,201
Regulatory Liabilities and Deferred Investment Tax Credits	893	988
Obligations Under Operating Leases	37	48
Deferred Credits and Other Noncurrent Liabilities	225	127
TOTAL NONCURRENT LIABILITIES	6,169	6,120
TOTAL LIABILITIES	8,059	7,815
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321	321
Paid-in Capital	1,030	1,020
Retained Earnings	2,800	2,543
TOTAL COMMON SHAREHOLDER'S EQUITY	4,151	3,884
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 12,210	$ 11,699

See Notes to Financial Statements of Registrants beginning on page 182.

OHIO POWER COMPANY AND SUBSIDIARIES
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	$ 328	$ 306	$ 328
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	380	386	316
Deferred Income Taxes	47	8	8
Asset Impairments and Other Related Charges	18	53	—
Allowance for Equity Funds Used During Construction	(25)	(23)	(17)
Mark-to-Market of Risk Management Contracts	(14)	(3)	11
Property Taxes	(22)	(25)	(12)
Change in Regulatory Assets	30	45	(91)
Change in Other Noncurrent Assets	(32)	(38)	(138)
Change in Other Noncurrent Liabilities	41	58	—
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	77	(170)	73
Materials and Supplies	(32)	55	(7)
Accounts Payable	57	6	24
Accrued Taxes, Net	11	76	28
Other Current Assets	5	(7)	—
Other Current Liabilities	(1)	43	(61)
Net Cash Flows from Operating Activities	868	770	462
INVESTING ACTIVITIES			
Construction Expenditures	(1,058)	(930)	(990)
Change in Advances to Affiliates, Net	115	(115)	—
Other Investing Activities	60	34	41
Net Cash Flows Used for Investing Activities	(883)	(1,011)	(949)
FINANCING ACTIVITIES			
Capital Contribution from Parent	10	7	175
Issuance of Long-term Debt – Nonaffiliated	—	346	395
Change in Advances from Affiliates, Net	79	(111)	(62)
Principal Payments for Finance Lease Obligations	(4)	(5)	(5)
Dividends Paid on Common Stock	(71)	—	(20)
Other Financing Activities	1	2	1
Net Cash Flows from Financing Activities	15	239	484
Net Decrease in Cash and Cash Equivalents	—	(2)	(3)
Cash and Cash Equivalents at Beginning of Period	5	7	10
Cash and Cash Equivalents at End of Period	$ 5	$ 5	$ 7
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 147	$ 139	$ 124
Noncash Acquisitions Under Finance Leases	2	2	4
Construction Expenditures Included in Current Liabilities as of December 31,	145	158	98

See Notes to Financial Statements of Registrants beginning on page 182.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2025	**2024**	**2023**
		(in millions of KWhs)	
Retail:			
Residential	6,197	6,293	6,138
Commercial	5,931	5,673	5,190
Industrial	5,864	5,882	5,932
Miscellaneous	1,265	1,279	1,255
Total Retail	19,257	19,127	18,515
Wholesale (a)	416	179	180
Total KWhs	19,673	19,306	18,695

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

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2025	**2024**	**2023**
		(in degree days)	
Actual – Heating	1,668	1,311	1,405
Normal – Heating	1,714	1,727	1,750
Actual – Cooling	2,163	2,450	2,330
Normal – Cooling	2,247	2,202	2,190

Public Service Company of Oklahoma
Reconciliation of Year Ended December 31, 2024 to Year Ended December 31, 2025
Net Income
(in millions)

Year Ended December 31, 2024	$	249
Changes in Revenues:		
Retail Revenues (a)		172
Transmission Revenues		11
Other Revenues		(7)
Total Change in Revenues		176
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation		(9)
Other Operation and Maintenance		(101)
Depreciation and Amortization		12
Taxes Other Than Income Taxes		(2)
Allowance for Funds Used During Construction		4
Non-Service Cost Components of Net Periodic Benefit Cost		(3)
Interest Expense		(44)
Total Change in Expenses and Other		(143)
Income Tax Benefit		(30)
Year Ended December 31, 2025	$	252

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

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

- **Retail Revenues** increased $172 million primarily due to the following:
  - A $205 million increase in base rate and rider revenues.
  - A $22 million increase in weather-normalized revenues primarily in the residential class partially offset by a decrease in the industrial class.

  These increases were partially offset by:
  - A $46 million decrease in fuel revenue primarily due to lower authorized fuel rates.
  - A $20 million decrease in weather-related usage driven by a 12% decrease in cooling degree days offset by a 27% increase in heating degree days.
- **Transmission Revenues** increased $11 million primarily due to continued transmission investment and the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- **Other Revenues** decreased $7 million primarily due to revenues from a customer project to enhance transmission resiliency in 2024.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $9 million primarily due to increased recoverable PTCs and increased fuel and purchased power costs, offset by lower current amortization of under-recovered deferred fuel regulatory assets as a result of lower authorized fuel rates.
- **Other Operation and Maintenance** expenses increased $101 million primarily due to the following:
  - A $62 million increase in transmission expenses primarily due to SPP expenses and the June 2025 FERC NOLC order.
  - A $13 million increase in generation expenses primarily due to acquisitions of generation facilities in 2025.
  - A $12 million increase in customer service and information expenses driven by energy efficiency programs.
  - A $12 million increase in distribution expenses primarily due to overhead line maintenance.
  - A $12 million increase in employee-related expenses.
  - A $7 million increase due to an impairment of in-process internal use software development costs.

These increases were partially offset by:

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

- **Depreciation and Amortization** expenses decreased $12 million primarily due to the following:
  - A $43 million decrease due to the under-recovery of regulatory assets related to renewables.
  - A $9 million decrease due to the under-recovery of regulatory assets related to Senate Bill 998 and the Dispatchable Resource Rider.

These decreases were partially offset by:

- A $41 million increase due to a higher depreciable base.

- **Interest Expense** increased $44 million primarily due to higher long-term debt balances and a prior year deferral of expenses as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail ratemaking.
- **Income Tax Benefit** decreased $30 million primarily due to the following:
  - A $48 million decrease due to a reduction in Excess ADIT regulatory liabilities as a result of the IRS PLR received regarding the treatment of standalone NOLCs in retail ratemaking recorded in 2024.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Public Service Company of Oklahoma

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Public Service Company of Oklahoma (the "Company") as of December 31, 2025 and 2024, and the related statements of income, of comprehensive income (loss), of changes in common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements 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.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements 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 of these financial statements 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 financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the 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 financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Cost-Based Regulation

As described in Notes 1 and 5 to the financial statements, the Company's 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 $674 million of deferred costs included in regulatory assets, $84 million of which were pending final regulatory approval, and $717 million of regulatory liabilities awaiting potential refund or future rate reduction. 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 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.

/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 Public Service Company of Oklahoma (PSO) 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. PSO'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 PSO'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 PSO's internal control over financial reporting was effective as of December 31, 2025.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, PSO's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit PSO to provide only management's report in this annual report.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF INCOME
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
REVENUES			
Electric Generation, Transmission and Distribution	$ 2,002	$ 1,820	$ 1,968
Sales to AEP Affiliates	9	7	1
Other Revenues	11	19	8
TOTAL REVENUES	2,022	1,846	1,977
EXPENSES			
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	752	743	955
Other Operation	501	416	356
Maintenance	129	113	112
Depreciation and Amortization	260	272	256
Taxes Other Than Income Taxes	79	77	64
TOTAL EXPENSES	1,721	1,621	1,743
OPERATING INCOME	301	225	234
Other Income (Expense):			
Interest Income	2	2	2
Allowance for Equity Funds Used During Construction	11	7	8
Non-Service Cost Components of Net Periodic Benefit Cost	8	11	14
Interest Expense	(140)	(96)	(103)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	182	149	155
Income Tax Expense (Benefit)	(70)	(100)	(54)
NET INCOME	$ 252	$ 249	$ 209

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

See Notes to Financial Statements of Registrants beginning on page 182.

PUBLIC SERVICE COMPANY OF OKLAHOMA
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	$ 252	$ 249	$ 209
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $0, $1 and $0 in 2025, 2024 and 2023, Respectively	(1)	4	(2)
TOTAL COMPREHENSIVE INCOME	$ 251	$ 253	$ 207

See Notes to Financial Statements of Registrants beginning on page 182.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	$ 157	$ 1,043	$ 1,218	$ 1	$ 2,419
Capital Contribution from Parent		1			1
Return of Capital to Parent		(4)			(4)
Common Stock Dividends			(52)		(52)
Net Income			209		209
Other Comprehensive Loss				(2)	(2)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2023	157	1,040	1,375	(1)	2,571
Capital Contribution from Parent		2			2
Common Stock Dividends			(140)		(140)
Net Income			249		249
Other Comprehensive Income				4	4
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2024	157	1,042	1,484	3	2,686
Capital Contribution from Parent		676			676
Net Income			252		252
Other Comprehensive Loss				(1)	(1)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2025	$ 157	$ 1,718	$ 1,736	$ 2	$ 3,613

See Notes to Financial Statements of Registrants beginning on page 182.

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

	December 31, 2025	December 31, 2024
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2	$ 2
Advances to Affiliates	—	232
Accounts Receivable:		
Customers	109	75
Affiliated Companies	45	33
Miscellaneous	4	—
Total Accounts Receivable	158	108
Fuel	3	17
Materials and Supplies	119	109
Risk Management Assets	42	21
Accrued Tax Benefits	8	36
Regulatory Asset for Under-Recovered Fuel Costs	37	65
Prepayments and Other Current Assets	14	18
TOTAL CURRENT ASSETS	383	608
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,365	2,772
Transmission	1,433	1,345
Distribution	3,987	3,699
Other Property, Plant and Equipment	1,292	550
Construction Work in Progress	635	379
Total Property, Plant and Equipment	11,712	8,745
Accumulated Depreciation and Amortization	2,748	2,213
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,964	6,532
OTHER NONCURRENT ASSETS		
Regulatory Assets	637	528
Employee Benefits and Pension Assets	95	74
Operating Lease Assets	126	106
Deferred Charges and Other Noncurrent Assets	13	62
TOTAL OTHER NONCURRENT ASSETS	871	770
TOTAL ASSETS	$ 10,218	$ 7,910

See Notes to Financial Statements of Registrants beginning on page 182.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2025 and 2024

	December 31, 2025	2024
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 171	$ —
Accounts Payable:		
General	339	201
Affiliated Companies	87	59
Long-term Debt Due Within One Year – Nonaffiliated	51	126
Risk Management Liabilities	27	6
Customer Deposits	115	73
Accrued Taxes	37	33
Accrued Interest	67	33
Obligations Under Operating Leases	11	10
Other Current Liabilities	104	78
TOTAL CURRENT LIABILITIES	1,009	619
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,475	2,730
Deferred Income Taxes	1,113	931
Regulatory Liabilities and Deferred Investment Tax Credits	717	690
Asset Retirement Obligations	136	119
Obligations Under Operating Leases	122	102
Deferred Credits and Other Noncurrent Liabilities	33	33
TOTAL NONCURRENT LIABILITIES	5,596	4,605
TOTAL LIABILITIES	6,605	5,224
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157	157
Paid-in Capital	1,718	1,042
Retained Earnings	1,736	1,484
Accumulated Other Comprehensive Income (Loss)	2	3
TOTAL COMMON SHAREHOLDER'S EQUITY	3,613	2,686
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 10,218	$ 7,910

See Notes to Financial Statements of Registrants beginning on page 182.

PUBLIC SERVICE COMPANY OF OKLAHOMA
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	$ 252	$ 249	$ 209
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	260	272	256
Deferred Income Taxes	150	21	8
Allowance for Equity Funds Used During Construction	(11)	(7)	(8)
Mark-to-Market of Risk Management Contracts	2	(27)	33
Deferred Fuel Over/Under-Recovery, Net	28	54	313
Change in Other Regulatory Assets	(54)	—	(108)
Change in Other Noncurrent Assets	4	(45)	(71)
Change in Other Noncurrent Liabilities	3	7	8
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(50)	32	(16)
Fuel, Materials and Supplies	8	15	(17)
Accounts Payable	68	18	(58)
Accrued Taxes, Net	31	(2)	(13)
Other Current Assets	2	(4)	10
Other Current Liabilities	52	(34)	45
Net Cash Flows from Operating Activities	745	549	591
INVESTING ACTIVITIES			
Construction Expenditures	(824)	(598)	(562)
Change in Advances to Affiliates, Net	232	(232)	—
Acquisitions of Generation Facilities	(1,676)	—	(146)
Other Investing Activities	10	5	15
Net Cash Flows Used for Investing Activities	(2,258)	(825)	(693)
FINANCING ACTIVITIES			
Capital Contribution from Parent	676	2	1
Return of Capital to Parent	—	—	(4)
Issuance of Long-term Debt – Nonaffiliated	793	596	470
Change in Advances from Affiliates, Net	171	(54)	(310)
Retirement of Long-term Debt – Nonaffiliated	(126)	(126)	(1)
Principal Payments for Finance Lease Obligations	(3)	(3)	(3)
Dividends Paid on Common Stock	—	(140)	(52)
Other Financing Activities	2	—	—
Net Cash Flows from Financing Activities	1,513	275	101
Net Decrease in Cash and Cash Equivalents	—	(1)	(1)
Cash and Cash Equivalents at Beginning of Period	2	3	4
Cash and Cash Equivalents at End of Period	$ 2	$ 2	$ 3
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 106	$ 102	$ 87
Noncash Acquisitions Under Finance Leases	2	2	2
Construction Expenditures Included in Current Liabilities as of December 31,	185	88	73

See Notes to Financial Statements of Registrants beginning on page 182.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2025	**2024**	**2023**
		(in millions of KWhs)	
Retail:			
Residential	6,276	6,081	6,138
Commercial	5,662	5,588	5,538
Industrial	5,155	5,157	5,147
Miscellaneous	67	69	71
Total Retail	17,160	16,895	16,894
Wholesale (a)	5,804	5,467	5,429
Total KWhs	22,964	22,362	22,323

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

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2025	**2024**	**2023**
		(in degree days)	
Actual – Heating	1,023	780	727
Normal – Heating	1,143	1,158	1,174
Actual – Cooling	2,868	3,041	2,853
Normal – Cooling	2,370	2,382	2,365

Reconciliation of Year Ended December 31, 2024 to Year Ended December 31, 2025
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Year Ended December 31, 2024	$	321
Changes in Revenues:		
Retail Revenues (a)		264
Off-system Sales		1
Transmission Revenues		50
Other Revenues		3
Total Change in Revenues		318
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation		6
Other Operation and Maintenance		(80)
Asset Impairments and Other Related Charges		(6)
Depreciation and Amortization		(40)
Taxes Other Than Income Taxes		(4)
Interest Income		(3)
Allowance for Equity Funds Used During Construction		9
Non-Service Cost Components of Net Periodic Benefit Cost		6
Interest Expense		(51)
Total Change in Expenses and Other		(163)
Income Tax Benefit		(89)
Equity Earnings of Unconsolidated Subsidiary		(1)
Net Income Attributable to Noncontrolling Interest		2
Year Ended December 31, 2025	$	388

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

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

- **Retail Revenues** increased $264 million primarily due to the following:
  - A $148 million increase due to a revenue refund provision recorded in 2024 associated with the Turk Plant and SWEPCo's 2012 Texas Base Rate Case.
  - A $106 million increase in rider revenues.
- **Transmission Revenues** increased $50 million primarily due to the following:
  - A $35 million increase due to continued transmission investment.
  - A $27 million increase due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

  These increases were partially offset by:
  - A $12 million decrease due to a provision for refund related to probable over-recovery of FERC transmission formula rates.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $6 million primarily due to a current year decrease in amortization of under-recovered deferred fuel regulatory assets.
- **Other Operation and Maintenance** expenses increased $80 million primarily due to the following:
  - A $51 million increase in transmission expenses primarily due to:
    - A $29 million increase due to continued transmission investment.
    - A $10 million increase related to the June 2025 FERC NOLC order.
    - An $8 million increase in vegetation management expenses.
  - A $32 million increase in distribution expenses primarily due to an increase in vegetation management and storm-related costs.
  - A $14 million increase in employee-related expenses.
  - A $12 million increase in renewable generation operation and maintenance expenses.

These increases were partially offset by:

- A $17 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 $6 million due to an impairment of in-process internal use software development costs.
- **Depreciation and Amortization** expenses increased $40 million primarily due to the following:
  - A $31 million increase due to a higher depreciable base.
  - A $20 million increase due to the amortization of the Storm Recovery Funding securitized assets.
  - A $6 million increase due to the amortization of an NOLC regulatory asset recognized in 2025.

  These increases were partially offset by:
  - An $18 million decrease due to the under-recovery of regulatory assets related to renewables.
- **Allowance for Equity Funds Used During Construction** increased $9 million primarily due to increased AFUDC base and rates.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $6 million primarily due to a plan remeasurement triggered by settlements related to the voluntary severance program in 2024.
- **Interest Expense** increased $51 million primarily due to the following:
  - A $28 million increase associated with Storm Recovery Funding securitization bonds.
  - A $28 million increase due to a prior year deferral of expenses in Texas as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail ratemaking.
- **Income Tax Benefit** decreased $89 million primarily due to the following:
  - A $109 million decrease due to a reduction in Excess ADIT regulatory liabilities as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail ratemaking recorded in 2024.
  - A $32 million decrease due to the reversal of a regulatory liability related to the merchant portion of Turk Plant Excess ADIT as a result of the APSC's denial of SWEPCo's request to allow the merchant portion of the Turk Plant to serve Arkansas customers recorded in 2024.
  - A $32 million decrease due to an increase in pretax book income.

  These decreases were partially offset by:
  - A $42 million increase due to a reduction in Excess ADIT primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
  - A $27 million increase due to an increase in PTCs.
  - A $14 million increase due to a decrease in state taxes.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Southwestern Electric Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Southwestern Electric Power Company 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 (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements 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.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements 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 of these consolidated financial statements 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits 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. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

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 $1,018 million of deferred costs included in regulatory assets, $445 million of which were pending final regulatory approval, and $576 million of regulatory liabilities awaiting potential refund or future rate reduction, $7 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.

/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 Southwestern Electric Power Company Consolidated (SWEPCo) 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. SWEPCo'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 SWEPCo'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 SWEPCo's internal control over financial reporting was effective as of December 31, 2025.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, SWEPCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit SWEPCo to provide only management's report in this annual report.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
REVENUES			
Electric Generation, Transmission and Distribution	$ 2,281	$ 2,149	$ 2,155
Sales to AEP Affiliates	71	71	82
(Provision for)/Reversal of – Revenue Refund – Affiliated	12	(9)	(35)
Provision for Refund	(20)	(182)	(21)
Other Revenues	10	7	2
TOTAL REVENUES	2,354	2,036	2,183
EXPENSES			
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	727	733	807
Other Operation	458	423	361
Maintenance	194	149	159
Asset Impairments and Other Related Charges	6	—	86
Depreciation and Amortization	429	389	343
Taxes Other Than Income Taxes	129	125	135
TOTAL EXPENSES	1,943	1,819	1,891
OPERATING INCOME	411	217	292
Other Income (Expense):			
Interest Income	11	14	19
Allowance for Equity Funds Used During Construction	23	14	11
Non-Service Cost Components of Net Periodic Benefit Cost	7	1	14
Interest Expense	(157)	(106)	(147)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	295	140	189
Income Tax Expense (Benefit)	(95)	(184)	(33)
Equity Earnings of Unconsolidated Subsidiary	1	2	2
NET INCOME	391	326	224
Net Income Attributable to Noncontrolling Interest	3	5	4
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 388	$ 321	$ 220

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

See Notes to Financial Statements of Registrants beginning on page 182.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
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	$ 391	$ 326	$ 224
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0, $0 and $0 in 2025, 2024 and 2023, Respectively	—	—	(1)
Pension and OPEB Funded Status, Net of Tax of $1, $2 and $1 in 2025, 2024 and 2023, Respectively	5	6	2
TOTAL OTHER COMPREHENSIVE INCOME	5	6	1
TOTAL COMPREHENSIVE INCOME	396	332	225
Total Comprehensive Income Attributable to Noncontrolling Interest	3	5	4
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 393	$ 327	$ 221

See Notes to Financial Statements of Registrants beginning on page 182.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2022	$ —	$ 1,442	$ 2,236	$ (4)	$ 1	$ 3,675
Capital Contribution from Parent		50				50
Common Stock Dividends			(175)			(175)
Common Stock Dividends – Nonaffiliated					(5)	(5)
Net Income			220		4	224
Other Comprehensive Income				1		1
TOTAL EQUITY – DECEMBER 31, 2023	—	1,492	2,281	(3)	—	3,770
Capital Contribution from Parent		59				59
Return of Capital to Parent		(1)				(1)
Common Stock Dividends			(250)			(250)
Common Stock Dividends – Nonaffiliated					(5)	(5)
Net Income			321		5	326
Other Comprehensive Income				6		6
TOTAL EQUITY – DECEMBER 31, 2024	—	1,550	2,352	3	—	3,905
Capital Contribution from Parent		601				601
Common Stock Dividends – Nonaffiliated					(3)	(3)
Net Income			388		3	391
Other Comprehensive Income				5		5
TOTAL EQUITY – DECEMBER 31, 2025	$ —	$ 2,151	$ 2,740	$ 8	$ —	$ 4,899

See Notes to Financial Statements of Registrants beginning on page 182.

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

	December 31, 2025	December 31, 2024
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2	$ 2
Restricted Cash (December 31, 2025 and 2024 Amounts Include $15 and $3, Respectively, Related to Storm Recovery Funding)	15	3
Advances to Affiliates	23	2
Accounts Receivable:		
Customers	63	35
Affiliated Companies	91	54
Miscellaneous	10	9
Total Accounts Receivable	164	98
Fuel	83	87
Materials and Supplies (December 31, 2025 and 2024 Amounts Include $1 and $2, Respectively, Related to Sabine)	88	81
Risk Management Assets	35	18
Accrued Tax Benefits	17	26
Regulatory Asset for Under-Recovered Fuel Costs	115	107
Prepayments and Other Current Assets	14	14
TOTAL CURRENT ASSETS	556	438
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,621	5,288
Transmission	3,302	2,864
Distribution	3,242	3,007
Other Property, Plant and Equipment (December 31, 2025 and 2024 Amounts Include $125 and $167, Respectively, Related to Sabine)	942	940
Construction Work in Progress	712	627
Total Property, Plant and Equipment	14,819	12,726
Accumulated Depreciation and Amortization (December 31, 2025 and 2024 Amounts Include $125 and $167, Respectively, Related to Sabine)	3,478	3,280
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	11,341	9,446
OTHER NONCURRENT ASSETS		
Regulatory Assets	903	921
Securitized Assets (December 31, 2025 and 2024 Amounts Include $315 and $331, Respectively, Related to Storm Recovery Funding)	315	331
Deferred Charges and Other Noncurrent Assets	409	359
TOTAL OTHER NONCURRENT ASSETS	1,627	1,611
TOTAL ASSETS	$ 13,524	$ 11,495

See Notes to Financial Statements of Registrants beginning on page 182.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2025 and 2024

	December 31, 2025	December 31, 2024
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 275
Accounts Payable:		
General	392	265
Affiliated Companies	89	57
Short-term Debt – Nonaffiliated	3	6
Long-term Debt Due Within One Year – Nonaffiliated (December 31, 2025 and 2024 Amounts Include $17 and $23, Respectively, Related to Storm Recovery Funding)	917	23
Risk Management Liabilities	9	2
Customer Deposits	79	75
Accrued Taxes	68	49
Accrued Interest	49	41
Obligations Under Operating Leases	7	8
Provision for Refund	81	71
Other Current Liabilities	191	160
TOTAL CURRENT LIABILITIES	1,885	1,032
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (December 31, 2025 and 2024 Amounts Include $304 and $309, Respectively, Related to Storm Recovery Funding)	3,057	3,958
Long-term Debt – Affiliated	1,000	—
Deferred Income Taxes	1,458	1,271
Regulatory Liabilities and Deferred Investment Tax Credits	531	611
Asset Retirement Obligations	252	257
Employee Benefits and Pension Obligations	39	46
Obligations Under Operating Leases	195	138
Provision for Refund	47	108
Storm Reserve	108	106
Deferred Credits and Other Noncurrent Liabilities	53	63
TOTAL NONCURRENT LIABILITIES	6,740	6,558
TOTAL LIABILITIES	8,625	7,590
Rate Matters (Notes 4)		
Commitments and Contingencies (Note 6)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 3,680 Shares		
Outstanding – 3,680 Shares	—	—
Paid-in Capital	2,151	1,550
Retained Earnings	2,740	2,352
Accumulated Other Comprehensive Income (Loss)	8	3
TOTAL COMMON SHAREHOLDER'S EQUITY	4,899	3,905
Noncontrolling Interest	—	—
TOTAL EQUITY	4,899	3,905
TOTAL LIABILITIES AND EQUITY	$ 13,524	$ 11,495

See Notes to Financial Statements of Registrants beginning on page 182.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
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	$ 391	$ 326	$ 224
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	429	389	343
Deferred Income Taxes	82	(74)	54
Asset Impairments and Other Related Charges	6	—	86
Allowance for Equity Funds Used During Construction	(23)	(14)	(11)
Mark-to-Market of Risk Management Contracts	(8)	(20)	19
Deferred Fuel Over/Under-Recovery, Net	104	156	184
Provision for Refund – Turk Plant	—	79	—
Change in Other Noncurrent Assets	(36)	(69)	(102)
Change in Other Noncurrent Liabilities	(125)	(41)	11
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(66)	(3)	20
Fuel, Materials and Supplies	(3)	29	(31)
Accounts Payable	77	3	(8)
Accrued Taxes, Net	28	(8)	(5)
Provision for Refund – Turk Plant	—	68	—
Other Current Assets	7	10	20
Other Current Liabilities	12	(14)	(1)
Net Cash Flows from Operating Activities	875	817	803
INVESTING ACTIVITIES			
Construction Expenditures	(935)	(741)	(781)
Change in Advances to Affiliates, Net	(21)	—	—
Acquisition of Renewable Energy Facilities	(1,229)	(399)	—
Other Investing Activities	14	11	4
Net Cash Flows Used for Investing Activities	(2,171)	(1,129)	(777)
FINANCING ACTIVITIES			
Capital Contribution from Parent	601	59	50
Return of Capital to Parent	—	(1)	—
Issuance of Long-term Debt – Nonaffiliated	—	336	347
Issuance of Long-term Debt – Affiliated	1,000	—	—
Change in Short-term Debt – Nonaffiliated	(3)	1	4
Change in Advances from Affiliates, Net	(275)	186	(222)
Retirement of Long-term Debt – Nonaffiliated	(11)	—	(94)
Principal Payments for Finance Lease Obligations	(4)	(14)	(19)
Dividends Paid on Common Stock	—	(250)	(175)
Dividends Paid on Common Stock – Nonaffiliated	(3)	(5)	(5)
Other Financing Activities	3	2	2
Net Cash Flows from (Used for) Financing Activities	1,308	314	(112)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	12	2	(86)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	5	3	89
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 17	$ 5	$ 3
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 156	$ 139	$ 129
Noncash Acquisitions Under Finance Leases	3	2	7
Construction Expenditures Included in Current Liabilities as of December 31,	225	137	64

See Notes to Financial Statements of Registrants beginning on page 182.

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.

Note	Registrant	Page Number
Organization and Summary of Significant Accounting Policies	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	183
New Accounting Standards	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	197
Comprehensive Income	AEP	199
Rate Matters	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	201
Effects of Regulation	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	214
Commitments, Guarantees and Contingencies	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	232
Acquisitions, Dispositions and Impairments	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	238
Benefit Plans	AEP, AEP Texas, APCo, I&M, OPCo, PSO, SWEPCo	242
Business Segments	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	258
Derivatives and Hedging	AEP, AEP Texas, APCo, I&M, OPCo, PSO, SWEPCo	263
Fair Value Measurements	AEP, AEP Texas, APCo, I&M, OPCo, PSO, SWEPCo	272
Income Taxes	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	283
Leases	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	292
Voluntary Severance Program	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	297
Financing Activities	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	298
Stock-based Compensation	AEP	307
Related Party Transactions	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	311
Variable Interest Entities and Equity Method Investments	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	315
Property, Plant and Equipment	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	323
Revenue from Contracts with Customers	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	329

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)

Cash Flow Information	Years Ended December 31, 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		Pension and OPEB		Total
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	
			(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. RATE MATTERS

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.

AEP Texas Rate Matters (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.

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

ENEC (Expanded Net Energy Cost) Filings

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

In February 2024, the Companies filed briefs with the West Virginia Supreme Court (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.

OPCo Rate Matters (Applies to AEP and OPCo)

OVEC Cost Recovery Audits

In December 2021, as part of OVEC cost recovery audits pending before the PUCO, intervenors filed positions claiming that costs incurred by OPCo during the 2018-2019 audit period were imprudent and should be disallowed. In May 2022, intervenors filed for rehearing on the 2016-2017 OVEC cost recovery audit period claiming the PUCO's April 2022 order to adopt the findings of the audit report were unjust, unlawful and unreasonable for multiple reasons, including the position that OPCo recovered imprudently incurred costs. In 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.

PSO Rate Matters (Applies to AEP and PSO)

2024 Oklahoma Base Rate Case

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

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

intervenor opposed the joint stipulation and settlement agreement. In October 2024, a hearing was held at the OCC, and PSO implemented an interim annual base rate increase of $120 million, subject to refund pending a final order by the OCC.

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

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.

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

North Central Wind Energy Facilities (NCWF)

The NCWF are subject to various regulatory performance requirements, including a Net Capacity Factor (NCF) guarantee. The NCF guarantee measures in MWhs across all facilities on a combined basis for each five year period for the first thirty full years of operation. The first NCF guarantee five year period began in April 2022. Certain wind turbines experienced performance issues that prompted PSO and SWEPCo to file a lawsuit against the manufacturer, which led to an agreement between PSO and SWEPCo and the manufacturer that addressed the performance issues. If regulatory performance requirements, such as the NCF guarantee, are not met, PSO and SWEPCo may recognize a regulatory liability associated with a refund to retail customers.

FERC Rate Matters

Independence Energy Connection Project (Applies to AEP)

In 2016, PJM approved the Independence Energy Connection Project (IEC) and included it in its Regional Transmission Expansion Plan to alleviate congestion. Transource Energy has an ownership interest in the IEC, which is located in Maryland and Pennsylvania. In June 2020, the Maryland Public Service Commission approved a CPCN to construct the portion of the IEC in Maryland. In May 2021, the Pennsylvania Public Utility Commission (PAPUC) denied the IEC certificate for siting and construction of the portion in Pennsylvania. Transource Energy appealed the PAPUC ruling in Pennsylvania state court and challenged the ruling before the United States District Court for the Middle District of Pennsylvania. In May 2022, the Pennsylvania state court issued an order affirming the PAPUC decision as to state law claims. In December 2023, the United States District Court for the Middle District of Pennsylvania granted summary judgment in favor of Transource Energy, finding that the PAPUC decision violated federal law and the United States Constitution. In January 2024, the PAPUC filed an appeal of the district court's grant of summary judgment with the United States Court of Appeals for the Third Circuit. In September 2025, the United States Court of Appeals for the Third Circuit affirmed the December 2023 district court order in favor of Transource Energy. 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,		
	2025	2024	Remaining Recovery Period
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)		
ver-recovered Fuel Costs - pays a return	$ 54	$ 22	1 year
ver-recovered Fuel Costs - does not pay a return	10	32	1 year
tal Current Regulatory Liabilities	$ 64	$ 54	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
egulatory liabilities pending final regulatory determination:			
egulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ 90	$ 176	
tal Regulatory Liabilities Currently Paying a Return	90	176	
egulatory Liabilities Currently Not Paying a Return			
FERC 2021 Transmission Formula Rate Challenge Refunds	—	131	
Other Regulatory Liabilities Pending Final Regulatory Determination	29	15	
tal Regulatory Liabilities Currently Not Paying a Return	29	146	
tal Regulatory Liabilities Pending Final Regulatory Determination	119	322	
egulatory liabilities approved for payment:			
egulatory 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
tal Regulatory Liabilities Currently Paying a Return	5,196	5,526	
egulatory 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
tal Regulatory Liabilities Currently Not Paying a Return	3,047	2,496	
tal Regulatory Liabilities Approved for Payment	8,243	8,022	
tal 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,		Remaining Recovery Period
	2025	2024	
	(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,		Remaining Refund Period
	2025	2024	
	(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	APCo December 31, 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	APCo December 31, 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.

Regulatory Assets:	I&M December 31, 2025	I&M December 31, 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,		Remaining Recovery Period
	2025	2024	
	(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	OPCo 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.

Regulatory Assets:	PSO December 31, 2025	PSO December 31, 2024	Remaining Recovery Period
	(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,		Remaining Refund Period
	2025	2024	
	(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 Change in Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(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 Change in Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(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 Change in Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(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 Change in Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(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

Pension Plans

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)

OPEB

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 Components	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(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 Components	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(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 Components	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(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 Components	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(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 Components	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(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 Components	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(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 Components	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(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 Components	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(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													
	December 31, 2025							December 31, 2024						
Primary Risk Exposure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)													
Commodity:														
Power (MWhs)	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
				(in millions)			
Assets:							
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
				(in millions)			
Assets:							
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
Assets:				(in millions)			
Current Risk Management Assets							
Gross Amounts Recognized	$ 776	$ —	$ 82	$ 23	$ —	$ 44	$ 37
Gross Amounts Offset	(424)	—	(1)	(13)	—	(2)	(2)
Net Amounts Presented	352	—	81	10	—	42	35
Long-term Risk Management Assets							
Gross Amounts Recognized	581	—	2	1	—	—	—
Gross Amounts Offset	(316)	—	(1)	(1)	—	—	—
Net Amounts Presented	265	—	1	—	—	—	—
Total Assets	$ 617	$ —	$ 82	$ 10	$ —	$ 42	$ 35
Liabilities:							
Current Risk Management Liabilities							
Gross Amounts Recognized	$ 532	$ —	$ 5	$ 13	$ 5	$ 29	$ 11
Gross Amounts Offset	(400)	—	(2)	(13)	—	(2)	(2)
Net Amounts Presented	132	—	3	—	5	27	9
Long-term Risk Management Liabilities							
Gross Amounts Recognized	438	—	1	1	28	1	2
Gross Amounts Offset	(260)	—	(1)	(1)	—	—	—
Net Amounts Presented	178	—	—	—	28	1	2
Total Liabilities	$ 310	$ —	$ 3	$ —	$ 33	$ 28	$ 11
Total MTM Derivative Contract Net Assets (Liabilities)	$ 307	$ —	$ 79	$ 10	$ (33)	$ 14	$ 24

	December 31, 2024						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Assets:				(in millions)			
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

Location of Gain (Loss)	Year Ended December 31, 2025						
	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

Location of Gain (Loss)	Year Ended December 31, 2024						
	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

Location of Gain (Loss)	Year Ended December 31, 2023						
	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

	December 31, 2024				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(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

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

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

APCo

	December 31, 2025				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 18	$ —	$ —	$ —	$ 18
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	3	81	(2)	82
Total Assets	$ 18	$ 3	$ 81	$ (2)	$ 100
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 6	$ —	$ (3)	$ 3

	December 31, 2024				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
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		Valuation Technique	Significant Unobservable Input (a)	Input/Range		
		Assets	Liabilities			Low	High	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		Valuation Technique	Significant Unobservable Input (a)	Input/Range		
		Assets	Liabilities			Low	High	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

	2025 Amount	2025 Percent	2024 Amount	2024 Percent	2023 Amount	2023 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

	2025 Amount	2025 Percent	2024 Amount	2024 Percent	2023 Amount	2023 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	Year Ended December 31, 2025		2024		2023	
	(dollars in millions)					
Net Income	$ 252		$ 249		$ 209	
Income Tax Expense (Benefit)	(70)		(100)		(54)	
Pretax Income	$ 182		$ 249		$ 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	Year Ended December 31, 2025		2024		2023	
	(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:

	Years Ended December 31,		
Company	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	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:

	Years Ended December 31,		
Assumptions	**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:

	Years Ended December 31,		
RSUs and Unrestricted Shares	**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:

	Years Ended December 31,		
RSUs and Unrestricted Shares	**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	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
		(in years)		(in years)		(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	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)		(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	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)		(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	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)		(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	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)		(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	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)		(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.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Information required by this item is set forth under the caption Proposal to Ratify the Appointment of the Independent Registered Public Accounting Firm in the 2026 Proxy Statement, which is incorporated by reference into this item.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

During 2025, management, including the principal executive officer and principal financial officer of each of the Registrants evaluated each respective Registrant's disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrant that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the Commission's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to each Registrant's management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of December 31, 2025, the principal executive officer and financial officer of each of the Registrants concluded that the disclosure controls and procedures in place were effective at the reasonable assurance level. The Registrants regularly strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

Changes in Internal Control over Financial Reporting

There have been no changes in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter 2025 that materially affected, or are reasonably likely to materially affect, the Registrants' internal control over financial reporting.

Internal Control over Financial Reporting

See Management's Report on Internal Control over Financial Reporting for each Registrant under Item 8. As discussed in that report, management assessed and reported on the effectiveness of each Registrant's internal control over financial reporting as of December 31, 2025. As a result of that assessment, management concluded that each Registrant's internal control over financial reporting was effective as of December 31, 2025.

ITEM 9B. OTHER INFORMATION

During the three months ended December 31, 2025, none of the Company's directors or officers (as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934) adopted, terminated or modified a Rule 10b5-1 trading arrangement or non-Rule 10b5-1 trading arrangement (as such terms are defined in Item 408 of Regulation S-K of the Securities Act of 1933).

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

AEP

Directors, Director Nomination Process and Audit Committee

Certain of the information called for in this Item 10, including the information relating to directors, is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2026 Annual Meeting of Shareholders (the 2026 Annual Meeting) including under the captions "Election of Directors," "AEP's Board of Directors and Committees," "Directors" and "Nominees for Directors."

Executive Officers

Reference also is made under the caption "Information About our Executive Officers" in Part I, Item 1 of this report.

Code of Ethics

AEP's Principles of Business Conduct is the code of ethics that applies to AEP's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The Principles of Business Conduct is available on AEP's website at www.aep.com. The Principles of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Investor Relations, American Electric Power Company, Inc., 1 Riverside Plaza, Columbus, Ohio 43215.

If any substantive amendments to the Principles of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Principles of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or Chief Accounting Officer, AEP will disclose the nature of such amendment or waiver on AEP's website, www.aep.com, or in a report on Form 8-K.

Insider Trading Policies and Procedures

AEP has an insider trading policy governing the purchase, sale and other dispositions of the company's debt and equity securities that applies to all company personnel, including directors, officers, employees, and other covered persons. The policy also applies to the company. The company believes that its insider trading policy is reasonably designed to promote compliance with insider trading laws, rules, and regulations, and NASDAQ listing standards applicable to the company. A copy of the company's insider trading policy is filed as Exhibit 19.1 to this Form 10-K. The remaining information required by this Item will be included in the company's definitive proxy statement which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act, relating to the 2026 Annual Meeting under the caption "Corporate Governance" and is incorporated herein by reference.

Delinquent Section 16(a) Reports

None.

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

ITEM 11. EXECUTIVE COMPENSATION

AEP

The information called for by this Item 11 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2026 Annual Meeting including under the captions "Compensation Discussion and Analysis," "Executive Compensation", "Director Compensation" and "2025 Director Compensation Table". The information set forth under the subcaption "Human Resources Committee Report" and "Audit Committee Report" should not be deemed filed nor should it be incorporated by reference into any other filing under the Securities Act of 1933, as amended, or the Exchange Act except to the extent AEP specifically incorporates such report by reference therein.

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

AEP

The information relating to Security Ownership of Certain Beneficial Owners is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to 2026 Annual Meeting under the caption "Share Ownership of Certain Beneficial Owners" and "Share Ownership of Directors and Executive Officers."

EQUITY COMPENSATION PLAN INFORMATION

The following table summarizes the ability of AEP to issue common stock pursuant to equity compensation plans as of December 31, 2025:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Equity Compensation Plans Approved by Security Holders	2,199,734	—	8,909,934
Equity Compensation Plans Not Approved by Security Holders	—	—	—
Total	2,199,734	—	8,909,934

(a) The balance includes unvested performance shares and restricted stock units as well as vested performance shares deferred as AEP career shares and stock units payable to outside directors after their service to the Company ends, all of which will be settled and paid in shares of AEP common stock. For performance shares, the total includes the target number of shares that could be granted if performance meets target objectives. The number of securities that would be granted, with respect to performance shares, if performance meets the maximum payout level, is two times the amount included in this total.

(b) No consideration is required from participants for the exercise or vesting of any outstanding AEP equity compensation awards.

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

AEP

The information called for by this Item 13 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2026 Annual Meeting under the captions "Certain Relationships and Related Person Transactions" and "Director Independence."

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

AEP

The information called for by this Item 14 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2026 Annual Meeting under the captions "Audit and Non-Audit Fees," "Audit Committee Report" and "Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of the Independent Auditor."

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Each of the above is a wholly-owned subsidiary of AEP and does not have a separate audit committee. A description of the AEP Audit Committee pre-approval policies, which apply to these companies, is contained in the definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2026 Annual Meeting under the captions "Audit and Non-Audit Fees," "Audit Committee Report" and "Policy on Audit Committee Pre-Approval of the Audit and Permissible Non-Audit Services of the Independent Auditor." The following table presents directly billed fees for professional services rendered by PricewaterhouseCoopers LLP for the audit of these companies' annual financial statements for the years ended December 31, 2025 and 2024, and fees directly billed for other services rendered by PricewaterhouseCoopers LLP during those periods. PricewaterhouseCoopers LLP also provides additional professional and other services to AEP subsidiaries, the cost of which may ultimately be allocated to these companies though not billed directly to them.

	AEP Texas		AEPTCo		APCo	
	2025	2024	2025	2024	2025	2024
Audit Fees	$ 1,496,490	$ 1,450,607	$ 1,817,864	$ 1,670,508	$ 1,776,943	$ 1,768,558
Audit-Related Fees	42,384	56,917	—	—	48,696	120,500
Total	$ 1,538,874	$ 1,507,524	$ 1,817,864	$ 1,670,508	$ 1,825,639	$ 1,889,058

	I&M		OPCo		PSO	
	2025	2024	2025	2024	2025	2024
Audit Fees	$ 1,517,387	$ 1,374,594	$ 1,171,100	$ 1,231,434	$ 863,009	$ 745,452
Audit-Related Fees	14,785	49,160	14,785	14,250	6,312	63,000
Total	$ 1,532,172	$ 1,423,754	$ 1,185,885	$ 1,245,684	$ 869,321	$ 808,452

	SWEPCo	
	2025	2024
Audit Fees	$ 1,067,604	$ 1,109,336
Audit-Related Fees	141,280	85,833
Total	$ 1,208,884	$ 1,195,169

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as a part of this report:

(a)(1) FINANCIAL STATEMENTS:

The following financial statements have been incorporated herein by reference pursuant to Item 8.

AEP and Subsidiary Companies:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2025, 2024 and 2023; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2025, 2024 and 2023; Consolidated Statements of Changes in Equity for the years ended December 31, 2025, 2024 and 2023; Consolidated Balance Sheets as of December 31, 2025 and 2024; Consolidated Statements of Cash Flows for the years ended December 31, 2025, 2024 and 2023; Notes to Financial Statements of Registrants.

AEP Texas, APCo and I&M:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2025, 2024 and 2023; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2025, 2024 and 2023; Consolidated Statements of Changes in Common Shareholder's Equity for the years ended December 31, 2025, 2024 and 2023; Consolidated Balance Sheets as of December 31, 2025 and 2024; Consolidated Statements of Cash Flows for the years ended December 31, 2025, 2024 and 2023; Notes to Financial Statements of Registrants.

AEPTCo:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2025, 2024 and 2023; Consolidated Statements of Changes in Member's Equity for the years ended December 31, 2025, 2024 and 2023; Consolidated Balance Sheets as of December 31, 2025 and 2024; Consolidated Statements of Cash Flows for the years ended December 31, 2025, 2024 and 2023; Notes to Financial Statements of Registrants.

OPCo:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2025, 2024 and 2023; Consolidated Statements of Changes in Common Shareholder's Equity for the years ended December 31, 2025, 2024 and 2023; Consolidated Balance Sheets as of December 31, 2025 and 2024; Consolidated Statements of Cash Flows for the years ended December 31, 2025, 2024 and 2023; Notes to Financial Statements of Registrants.

PSO:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Statements of Income for the years ended December 31, 2025, 2024 and 2023; Statements of Comprehensive Income (Loss) for the years ended December 31, 2025, 2024 and 2023; Statements of Changes in Common Shareholder's Equity for the years ended December 31, 2025, 2024 and 2023; Balance Sheets as of December 31, 2025 and 2024; Statements of Cash Flows for the years ended December 31, 2025, 2024 and 2023; Notes to Financial Statements of Registrants.

SWEPCo:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2025, 2024 and 2023; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2025, 2024 and 2023; Consolidated Statements of Changes in Equity for the years ended December 31, 2025, 2024 and 2023; Consolidated Balance Sheets as of December 31, 2025 and 2024; Consolidated Statements of Cash Flows for the years ended December 31, 2025, 2024 and 2023; Notes to Financial Statements of Registrants.

(a)(2) FINANCIAL STATEMENT SCHEDULES:	Page Number
Schedule I	
Condensed Financial Information of American Electric Power Company, Inc. (Parent)	
Condensed Statements of Income and Comprehensive Income - Years Ended December 31, 2025, 2024 and 2023	S-2
Condensed Balance Sheets - December 31, 2025 and 2024	S-3
Condensed Statements of Cash Flows - Years Ended December 31, 2025, 2024 and 2023	S-5
Condensed Notes to Condensed Financial Information	S-6
Schedule II	
AEP	
Valuation and Qualifying Accounts and Reserves - Years Ended December 31, 2025, 2024 and 2023	S-9
Schedule I	
Condensed Financial Information of AEP Transmission Company, LLC (AEPTCo Parent)	
Condensed Statements of Income - Years Ended December 31, 2025, 2024 and 2023	S-11
Condensed Balance Sheets - December 31, 2025 and 2024	S-12
Condensed Statements of Cash Flows - Years Ended December 31, 2025, 2024 and 2023	S-14
Condensed Notes to Condensed Financial Information	S-15

Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable.

(a)(3) EXHIBITS:	
Exhibits for AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo are listed in the Exhibit Index beginning on page E-1 and are incorporated herein by reference.	E-1

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

American Electric Power Company, Inc.

By: /s/ Trevor I. Mihalik
(Trevor I. Mihalik, Executive Vice President and Chief Financial Officer)

Date: February 12, 2026

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ William J. Fehrman **(William J. Fehrman)**	Chair of the Board, President and Chief Executive Officer	February 12, 2026
(ii) Principal Financial Officer:		
/s/ Trevor I. Mihalik **(Trevor I. Mihalik)**	Executive Vice President and Chief Financial Officer	February 12, 2026
(iii) Principal Accounting Officer:		
/s/ Kate Dixon **(Kate Dixon)**	Senior Vice President, Controller and Chief Accounting Officer	February 12, 2026
(iv) A Majority of the Directors:		
/s/ William J. Fehrman *Benjamin G.S. Fowke, III *Art A. Garcia *Hunter C. Gary *Sandra Beach Lin *Henry P. Linginfelter *Margaret M. McCarthy *Daryl Roberts *Joseph G. Sauvage *Daniel G. Stoddard *Sara Martinez Tucker *Lewis Von Thaer		
*By: /s/ Trevor I. Mihalik **(Trevor I. Mihalik, Attorney-in-Fact)**		February 12, 2026

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AEP Texas Inc.

By: /s/ Trevor I. Mihalik
(Trevor I. Mihalik, Vice President and Chief Financial Officer)

Date: February 12, 2026

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ William J. Fehrman **(William J. Fehrman)**	Chair of the Board, Chief Executive Officer and Director	February 12, 2026
(ii) Principal Financial Officer:		
/s/ Trevor I. Mihalik **(Trevor I. Mihalik)**	Vice President, Chief Financial Officer and Director	February 12, 2026
(iii) Principal Accounting Officer:		
/s/ Kate Dixon **(Kate Dixon)**	Chief Accounting Officer	February 12, 2026
(iv) A Majority of the Directors:		
*Robert B. Berntsen *William J. Fehrman *Judith E. Talavera Trevor I. Mihalik		
*By: /s/ Trevor I. Mihalik **(Trevor I. Mihalik, Attorney-in-Fact)**		February 12, 2026

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AEP Transmission Company, LLC

By: /s/ Trevor I. Mihalik
(Trevor I. Mihalik, Vice President and Chief Financial Officer)

Date: February 12, 2026

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ William J. Fehrman **(William J. Fehrman)**	Chair of the Board, Chief Executive Officer and Manager	February 12, 2026
(ii) Principal Financial Officer:		
/s/ Trevor I. Mihalik **(Trevor I. Mihalik)**	Vice President, Chief Financial Officer and Manager	February 12, 2026
(iii) Principal Accounting Officer:		
/s/ Kate Dixon **(Kate Dixon)**	Chief Accounting Officer	February 12, 2026
(iv) A Majority of the Managers:		
*Robert B. Berntsen *William J. Fehrman Trevor I. Mihalik		
*By: /s/ Trevor I. Mihalik **(Trevor I. Mihalik, Attorney-in-Fact)**		February 12, 2026

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Appalachian Power Company

By: /s/ Trevor I. Mihalik
(Trevor I. Mihalik, Vice President and Chief Financial Officer)

Date: February 12, 2026

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ William J. Fehrman **(William J. Fehrman)**	Chair of the Board, Chief Executive Officer and Director	February 12, 2026
(ii) Principal Financial Officer:		
/s/ Trevor I. Mihalik **(Trevor I. Mihalik)**	Vice President, Chief Financial Officer and Director	February 12, 2026
(iii) Principal Accounting Officer:		
/s/ Kate Dixon **(Kate Dixon)**	Chief Accounting Officer	February 12, 2026
(iv) A Majority of the Directors:		
*Robert B. Berntsen *William J. Fehrman *Aaron D. Walker Trevor I. Mihalik		
*By: /s/ Trevor I. Mihalik **(Trevor I. Mihalik, Attorney-in-Fact)**		February 12, 2026

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Indiana Michigan Power Company

By: /s/ Trevor I. Mihalik
(Trevor I. Mihalik, Vice President and Chief Financial Officer)

Date: February 12, 2026

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ William J. Fehrman **(William J. Fehrman)**	Chair of the Board, Chief Executive Officer and Director	February 12, 2026
(ii) Principal Financial Officer:		
/s/ Trevor I. Mihalik **(Trevor I. Mihalik)**	Vice President, Chief Financial Officer and Director	February 12, 2026
(iii) Principal Accounting Officer:		
/s/ Kate Dixon **(Kate Dixon)**	Chief Accounting Officer	February 12, 2026
(iv) A Majority of the Directors:		
*Steven F. Baker *Robert B. Berntsen *William J. Fehrman Scott A. Huebner *Katherine K. Runkle *Stephanny L. Smith *Andrew J. Williamson Trevor I. Mihalik		
*By: /s/ Trevor I. Mihalik **(Trevor I. Mihalik, Attorney-in-Fact)**		February 12, 2026

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Ohio Power Company

By: /s/ Trevor I. Mihalik
(Trevor I. Mihalik, Vice President and Chief Financial Officer)

Date: February 12, 2026

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ William J. Fehrman **(William J. Fehrman)**	Chair of the Board, Chief Executive Officer and Director	February 12, 2026
(ii) Principal Financial Officer:		
/s/ Trevor Mihalik **(Trevor I. Mihalik)**	Vice President, Chief Financial Officer and Director	February 12, 2026
(iii) Principal Accounting Officer:		
/s/ Kate Dixon **(Kate Dixon)**	Chief Accounting Officer	February 12, 2026
(iv) A Majority of the Directors:		
*Robert B. Berntsen *William J. Fehrman *Marc D. Reitter Trevor I. Mihalik		
*By: /s/ Trevor I. Mihalik **(Trevor I. Mihalik, Attorney-in-Fact)**		February 12, 2026

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Public Service Company of Oklahoma

By: /s/ Trevor I. Mihalik
(Trevor I. Mihalik, Vice President and Chief Financial Officer)

Date: February 12, 2026

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ William J. Fehrman **(William J. Fehrman)**	Chair of the Board, Chief Executive Officer and Director	February 12, 2026
(ii) Principal Financial Officer:		
/s/ Trevor I. Mihalik **(Trevor I. Mihalik)**	Vice President, Chief Financial Officer and Director	February 12, 2026
(iii) Principal Accounting Officer:		
/s/ Kate Dixon **(Kate Dixon)**	Chief Accounting Officer	February 12, 2026
(iv) A Majority of the Directors:		
*Robert B. Berntsen *William J. Fehrman *Leigh Anne Strahler Trevor I. Mihalik		
*By: /s/ Trevor I. Mihalik **(Trevor I. Mihalik, Attorney-in-Fact)**		February 12, 2026

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Southwestern Electric Power Company

By: /s/ Trevor I. Mihalik
(Trevor I. Mihalik, Vice President and Chief Financial Officer)

Date: February 12, 2026

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ William J. Fehrman **(William J. Fehrman)**	Chair of the Board, Chief Executive Officer and Director	February 12, 2026
(ii) Principal Financial Officer:		
/s/ Trevor I. Mihalik **(Trevor I. Mihalik)**	Vice President, Chief Financial Officer and Director	February 12, 2026
(iii) Principal Accounting Officer:		
/s/ Kate Dixon **(Kate Dixon)**	Chief Accounting Officer	February 12, 2026
(iv) A Majority of the Directors:		
*Robert B. Berntsen *William J. Fehrman *D. Brett Mattison Trevor I. Mihalik		
*By: /s/ Trevor I. Mihalik **(Trevor I. Mihalik, Attorney-in-Fact)**		February 12, 2026

INDEX OF FINANCIAL STATEMENT SCHEDULES

	Page Number
The following financial statement schedules are included in this report on the pages indicated:	
American Electric Power Company, Inc. (Parent):	
Schedule I – Condensed Financial Information	S-2
Schedule I – Condensed Notes to Condensed Financial Information	S-6
American Electric Power Company, Inc. and Subsidiary Companies:	
Schedule II – Valuation and Qualifying Accounts and Reserves	S-9

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE 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			
Revenues	$ 7	$ 6	$ 5
TOTAL REVENUES	7	6	5
EXPENSES			
Other Operation	35	66	17
Depreciation and Amortization	1	1	1
Amortization of KPCo Basis Difference	(21)	(21)	(17)
TOTAL EXPENSES	15	46	1
OPERATING INCOME (LOSS)	(8)	(40)	4
Other Income (Expense):			
Interest Income	102	108	181
Interest Expense	(548)	(532)	(526)
LOSS BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	(454)	(464)	(341)
Income Tax Expense (Benefit)	(126)	(151)	(81)
Equity Earnings of Unconsolidated Subsidiaries	3,908	3,280	2,468
NET INCOME	3,580	2,967	2,208
Other Comprehensive Income (Loss)	39	52	(139)
TOTAL COMPREHENSIVE INCOME	$ 3,619	$ 3,019	$ 2,069
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 Condensed Notes to Condensed Financial Information beginning on page S-6.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
ASSETS
December 31, 2025 and 2024
(in millions)

	December 31, 2025	December 31, 2024
CURRENT ASSETS		
Cash and Cash Equivalents	$ 103	$ 88
Advances to Affiliates	1,879	1,945
Accounts Receivable:		
Affiliated Companies	23	33
Total Accounts Receivable	23	33
Prepayments and Other Current Assets	75	107
TOTAL CURRENT ASSETS	2,080	2,173
PROPERTY, PLANT AND EQUIPMENT		
General	3	3
Total Property, Plant and Equipment	3	3
Accumulated Depreciation, Depletion and Amortization	2	1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1	2
OTHER NONCURRENT ASSETS		
Investments in Unconsolidated Subsidiaries	39,550	35,306
Affiliated Notes Receivable	1,105	105
Deferred Charges and Other Noncurrent Assets	245	184
TOTAL OTHER NONCURRENT ASSETS	40,900	35,595
TOTAL ASSETS	$ 42,981	$ 37,770

See Condensed Notes to Condensed Financial Information beginning on page S-6.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2025 and 2024
(dollars in millions)

	December 31, 2025	December 31, 2024
CURRENT LIABILITIES		
Advances from Affiliates	$ 887	$ 507
Accounts Payable:		
General	1	5
Affiliated Companies	5	2
Short-term Debt	605	1,618
Long-term Debt Due Within One Year – Nonaffiliated	50	1,282
Accrued Interest	129	104
Other Current Liabilities	47	98
TOTAL CURRENT LIABILITIES	1,724	3,616
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	10,050	7,124
Deferred Credits and Other Noncurrent Liabilities	31	48
TOTAL NONCURRENT LIABILITIES	10,081	7,172
TOTAL LIABILITIES	11,805	10,788
Contingently Redeemable Performance Share Awards	38	38
COMMON SHAREHOLDERS' 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	
(1,186,815 Shares were Held in Treasury as of December 31, 2025 and 2024)	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
TOTAL LIABILITIES AND EQUITY	$ 42,981	$ 37,770

See Condensed Notes to Condensed Financial Information beginning on page S-6.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED 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	$ 3,580	$ 2,967	$ 2,208
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1	1	1
Amortization of KPCo Basis Difference	(21)	(21)	(17)
Deferred Income Taxes	(12)	(53)	60
Equity Earnings of Unconsolidated Subsidiaries	(3,908)	(3,280)	(2,468)
Cash Dividends Received from Unconsolidated Subsidiaries	3,483	1,143	686
Change in Other Noncurrent Assets	(3)	5	(28)
Change in Other Noncurrent Liabilities	61	71	92
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	10	18	29
Accounts Payable	(1)	(17)	(16)
Other Current Assets	10	—	(4)
Other Current Liabilities	10	55	(14)
Net Cash Flows from Operating Activities	3,210	889	529
INVESTING ACTIVITIES			
Construction Expenditures	(48)	(1)	(1)
Change in Advances to Affiliates, Net	66	60	2,008
Investment in Equity Method Investments	(100)	—	—
Capital Contributions to Unconsolidated Subsidiaries	(1,869)	(400)	(790)
Return of Capital Contributions from Unconsolidated Subsidiaries	—	899	57
Issuance of Notes Receivable to Unconsolidated Subsidiaries	(1,000)	—	(210)
Repayment of Notes Receivable from Unconsolidated Subsidiaries	—	190	—
Net Cash Flows from (Used for) Investing Activities	(2,951)	748	1,064
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	775	552	1,000
Issuance of Long-term Debt	2,966	1,285	1,830
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	(655)	(172)	(1,365)
Retirement of Long-term Debt	(1,300)	(1,104)	(1,050)
Change in Advances from Affiliates, Net	380	(222)	(192)
Redemption of Short-term Debt with Original Maturities Greater Than 90 Days	(678)	(871)	(1,129)
Dividends Paid on Common Stock	(2,008)	(1,898)	(1,752)
Other Financing Activities	(44)	(41)	(61)
Net Cash Flows Used for Financing Activities	(244)	(1,747)	(1,649)
Net Increase (Decrease) in Cash and Cash Equivalents	15	(110)	(56)
Cash and Cash Equivalents at Beginning of Period	88	198	254
Cash and Cash Equivalents at End of Period	$ 103	$ 88	$ 198

See Condensed Notes to Condensed Financial Information beginning on page S-6.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The condensed financial information of Parent is required as a result of the restricted net assets of AEP consolidated subsidiaries exceeding 25% of AEP consolidated net assets as of December 31, 2025. Parent is a public utility holding company that owns all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries, including joint ventures and equity investments. The primary source of income for Parent is equity in its subsidiaries' earnings. Its major source of cash is dividends from its wholly-owned subsidiaries, which are evaluated for cash flow presentation based on the nature of the distribution. Parent borrows the funds for the money pool that is used by the subsidiaries for their short-term cash needs. Parent financial statements should be read in conjunction with the AEP consolidated financial statements and the accompanying notes thereto. For purposes of these condensed financial statements, AEP wholly-owned and majority-owned subsidiaries are recorded based upon its proportionate share of the subsidiaries' net assets (similar to presenting them on the equity method).

Income Taxes

Parent files a consolidated federal income tax return with its subsidiaries. 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.

2. COMMITMENTS, GUARANTEES AND CONTINGENCIES

Parent and its subsidiaries are parties to environmental and other legal matters. For further discussion, see Note 6 - Commitments, Guarantees and Contingencies.

3. FINANCING ACTIVITIES

The following details long-term debt outstanding as of December 31, 2025 and 2024:

Long-term Debt

Type of Debt	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
					(in millions)	
Senior Unsecured Notes	2027-2050	4.58%	1.80%-5.95%	1.00%-5.95%	$ 4,882	$ 5,290
Pollution Control Bonds	2026-2029 (a)	3.12%	2.40%-3.75%	2.40%-3.75%	537	537
Junior Subordinated Notes	2027-2054	5.83%	3.88%-7.05%	3.88%-7.05%	4,681	2,579
Total Long-term Debt Outstanding					10,100	8,406
Long-term Debt Due Within One Year					50	1,282
Long-term Debt					$ 10,050	$ 7,124

(a) Certain Pollution Control Bonds are subject to redemption earlier than the maturity date.

Long-term debt outstanding as of December 31, 2025 is payable as follows:

	2026	2027	2028	2029	2030	After 2030	Total
				(in millions)			
Principal Amount (a)	$ 50	$ 1,774	$ 930	$ 1,695	$ 400	$ 5,350	$ 10,199
Unamortized Discount, Net and Debt Issuance Costs							(99)
Total Long-term Debt Outstanding							$ 10,100

(a) Amounts reflect the impact of fair value hedge accounting. See “Accounting for Fair Value Hedging Strategies” section of Note 10 included in the 2025 Annual Report for additional information.

Short-term Debt

Parent’s outstanding short-term debt was as follows:

Type of Debt	December 31, 2025 Outstanding Amount	December 31, 2025 Weighted-Average Interest Rate	December 31, 2024 Outstanding Amount	December 31, 2024 Weighted-Average Interest Rate
	(in millions)		(in millions)	
Commercial Paper	$ 605	3.92 %	$ 1,618	4.70 %
Total Short-term Debt	$ 605		$ 1,618	

4. RELATED PARTY TRANSACTIONS

Payments on Behalf of Subsidiaries

Due to occasional time sensitivity and complexity of payments, Parent makes certain insurance, tax and benefit payments on behalf of subsidiary companies. Parent is then fully reimbursed by the subsidiary companies.

Short-term Lending to Subsidiaries

Parent uses a commercial paper program to meet the short-term borrowing needs of subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds certain nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The program also allows some direct borrowers to invest excess cash with Parent.

Interest expense related to Parent's short-term borrowing is included in Interest Expense on Parent's statements of income. Parent incurred interest expense for amounts borrowed from subsidiaries of $31 million, $28 million and $33 million for the years ended December 31, 2025, 2024 and 2023, respectively.

Interest income related to Parent's short-term lending is included in Interest Income on Parent's statements of income. Parent earned interest income for amounts advanced to subsidiaries of $88 million, $84 million and $164 million for the years ended December 31, 2025, 2024 and 2023, respectively.

Affiliated Notes

Parent issued long-term debt, portions of which were loaned to its subsidiaries. Parent pays interest on the affiliated notes, but the subsidiaries accrue interest for their share of the affiliated borrowing and remit the interest to Parent. Interest income related to Parent's loans to subsidiaries is included in Interest Income on Parent's statements of income. Parent earned interest income on loans to subsidiaries of $7 million, $7 million and $6 million for the years ended December 31, 2025, 2024 and 2023, respectively.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

AEP

Description	Balance at Beginning of Period	Additions		Deductions (b)	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts (a)		
			(in millions)		
Deducted from Assets:					
Allowance for Credit Losses:					
Year Ended December 31, 2025	$ 61	$ 50	$ 2	$ 61	$ 52
Year Ended December 31, 2024	60	45	3	47	61
Year Ended December 31, 2023	57	15	—	12	60

(a) Recoveries offset by reclasses to other assets and liabilities.
(b) Uncollectible accounts written off.

Schedule II for the Registrant Subsidiaries is not presented because the amounts are not material.

INDEX OF AEP TRANSMISSION COMPANY, LLC (AEPTCO PARENT)
FINANCIAL STATEMENT SCHEDULES

	Page Number
The following financial statement schedules are included in this report on the pages indicated:	
AEP Transmission Company, LLC (AEPTCo Parent):	
Schedule I – Condensed Financial Information	S-11
Schedule I – Condensed Notes to Condensed Financial Information	S-15

SCHEDULE I
AEP TRANSMISSION COMPANY, LLC (AEPTCo Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF INCOME
For the Years Ended December 31, 2025, 2024 and 2023
(in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
EXPENSES			
Other Operation	$ —	$ 2	$ —
TOTAL EXPENSES	—	2	—
OPERATING LOSS	—	(2)	—
Other Income (Expense):			
Interest Income - Affiliated	308	241	218
Interest Expense	(257)	(239)	(215)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS OF UNCONSOLIDATED SUBSIDIARIES	51	—	3
Income Tax Expense	11	—	2
Equity Earnings of Unconsolidated Subsidiaries	1,035	688	613
NET INCOME	$ 1,075	$ 688	$ 614

See Condensed Notes to Condensed Financial Information beginning on page S-15.

SCHEDULE I
AEP TRANSMISSION COMPANY, LLC (AEPTCo Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
ASSETS
December 31, 2025 and 2024
(in millions)

	December 31, 2025	December 31, 2024
CURRENT ASSETS		
Advances to Affiliates	$ 70	$ 20
Accounts Receivable:		
General	32	—
Affiliated Companies	65	62
Total Accounts Receivable	97	62
Notes Receivable - Affiliated	425	90
TOTAL CURRENT ASSETS	592	172
OTHER NONCURRENT ASSETS		
Notes Receivable - Affiliated	6,174	8,498
Investments in Unconsolidated Subsidiaries	6,690	4,273
TOTAL OTHER NONCURRENT ASSETS	12,864	12,771
TOTAL ASSETS	$ 13,456	$ 12,943

See Condensed Notes to Condensed Financial Information beginning on page S-15.

SCHEDULE I
AEP TRANSMISSION COMPANY, LLC (AEPTCo Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2025 and 2024
(in millions)

	December 31, 2025	December 31, 2024
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 81	$ 69
Affiliated Companies	112	95
Long-term Debt Due Within One Year – Nonaffiliated	425	90
Accrued Interest	46	45
Other Current Liabilities	5	15
TOTAL CURRENT LIABILITIES	669	314
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	6,174	5,678
TOTAL NONCURRENT LIABILITIES	6,174	5,678
TOTAL LIABILITIES	6,843	5,992
MEMBER'S EQUITY		
Paid-in Capital	4,962	3,101
Retained Earnings	1,651	3,850
TOTAL MEMBER'S EQUITY	6,613	6,951
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 13,456	$ 12,943

See Condensed Notes to Condensed Financial Information beginning on page S-15.

SCHEDULE I
AEP TRANSMISSION COMPANY, LLC (AEPTCo Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED 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	$ 1,075	$ 688	$ 614
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:			
Equity Earnings of Unconsolidated Subsidiaries	(1,035)	(688)	(613)
Change in Other Noncurrent Assets	—	—	4
Change in Other Noncurrent Liabilities	7	4	12
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(35)	10	(38)
Accounts Payable	29	13	37
Accrued Interest	1	6	11
Other Current Liabilities	(9)	34	(31)
Net Cash Flows from (Used for) Operating Activities	33	67	(4)
INVESTING ACTIVITIES			
Change in Advances to Affiliates, Net	(50)	(20)	—
Repayment of Notes Receivable from Affiliated Companies	2,922	95	60
Issuance of Notes Receivable to Affiliated Companies	(936)	(450)	(700)
Return of Capital Contributions from Unconsolidated Subsidiaries	739	133	184
Capital Contributions to Subsidiaries	(189)	(62)	(30)
Net Cash Flows from (Used for) Investing Activities	2,486	(304)	(486)
FINANCING ACTIVITIES			
Capital Contributions from Member	70	62	30
Return of Capital to Member	—	(5)	(9)
Issuance of Long-term Debt – Nonaffiliated	929	446	689
Retirement of Long-term Debt – Nonaffiliated	(102)	(95)	(60)
Change in Advances from Affiliates, Net	—	(43)	15
Dividends Paid	(3,379)	(128)	(175)
Other Financing Activities	(37)	—	—
Net Cash Flows from (Used for) Financing Activities	(2,519)	237	490
Net Change in Cash and Cash Equivalents	—	—	—
Cash and Cash Equivalents at Beginning of Period	—	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —	$ —

See Condensed Notes to Condensed Financial Information beginning on page S-15.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The condensed financial information of AEPTCo Parent is required as a result of the restricted net assets of AEPTCo consolidated subsidiaries exceeding 25% of AEPTCo consolidated net assets as of December 31, 2025. AEPTCo Parent is the direct holding company for the seven State Transcos. The primary source of income for AEPTCo Parent is equity in its subsidiaries' earnings. AEPTCo Parent financial statements should be read in conjunction with the AEPTCo consolidated financial statements and the accompanying notes thereto. For purposes of these condensed financial statements, AEPTCo wholly-owned and majority-owned subsidiaries are recorded based upon its proportionate share of the subsidiaries' net assets (similar to presenting them on the equity method).

Income Taxes

AEPTCo Parent joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. 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.

Noncontrolling Interest in Midwest Transmission Holdings

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. See Note 4 - Related Party Transactions for additional information.

2. COMMITMENTS, GUARANTEES AND CONTINGENCIES

AEPTCo Parent and its subsidiaries are parties to legal matters. For further discussion, see Note 6 - Commitments, Guarantees and Contingencies.

3. FINANCING ACTIVITIES

For discussion of Financing Activities, see Note 15 - Financing Activities to AEPTCo's audited consolidated financial statements.

4. RELATED PARTY TRANSACTIONS

Payments on Behalf of Subsidiaries

Due to occasional time sensitivity and complexity of payments, Parent makes certain insurance, tax and other payments on behalf of subsidiary companies. Parent is then fully reimbursed by the subsidiary companies. AEPTCo Parent also makes convenience payments on behalf of its State Transcos. AEPTCo Parent is then fully reimbursed by its State Transcos.

Long-term Lending to Subsidiaries

AEPTCo Parent enters into debt arrangements with nonaffiliated entities. AEPTCo Parent has long-term debt of $6.6 billion and $5.8 billion as of December 31, 2025 and 2024, respectively. AEPTCo Parent uses the proceeds from these nonaffiliated debt arrangements to make affiliated loans to its State Transcos using the same interest rates and maturity dates as the nonaffiliated debt arrangements. AEPTCo Parent has recorded Notes Receivable – Affiliated of $6.6 billion and $8.6 billion as of December 31, 2025 and 2024, respectively. Related to these nonaffiliated and affiliated debt arrangements, AEPTCo Parent has recorded Accrued Interest of $46 million and $45 million as of December 31, 2025 and 2024, respectively. AEPTCo Parent has also recorded Accounts Receivable – Affiliated Companies of $65 million and $62 million as of December 31, 2025 and 2024, respectively. AEPTCo Parent has recorded Interest Income – Affiliated of $306 million, $238 million and $215 million for the years ended December 31, 2025, 2024 and 2023, respectively, related to Notes Receivable – Affiliated. AEPTCo Parent has recorded Interest Expense of $252 million, $238 million and $215 million for the years ended December 31, 2025, 2024 and 2023, respectively, related to the nonaffiliated debt arrangements.

Short-term Lending to Subsidiaries

Parent uses a commercial paper program to meet the short-term borrowing needs of subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds certain nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The program also allows some direct borrowers to invest excess cash with Parent.

Interest expense related to AEPTCo Parent's short-term borrowing is included in Interest Expense on AEPTCo Parent's statements of income. AEPTCo Parent incurred immaterial interest expense for amounts borrowed from AEP affiliates for the years ended December 31, 2025, 2024 and 2023.

Interest income related to AEPTCo Parent's short-term lending is included in Interest Income – Affiliated on AEPTCo Parent's statements of income. AEPTCo Parent earned interest income for amounts advanced to AEP affiliates of $2 million, $3 million and $3 million for the years ended December 31, 2025, 2024 and 2023, respectively.

EXHIBIT INDEX

The documents listed below are being filed or have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof. Exhibits ("Ex") not identified as previously filed are filed herewith. Exhibits designated with a dagger (†) are management contracts or compensatory plans or arrangements required to be filed as an Exhibit to this Form. Exhibits designated with an asterisk (*) are filed herewith.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
AEP‡ File No. 1-3525		
3(a)	Composite of the Restated Certificate of Incorporation of AEP, dated April 26, 2022.	2023 Form 10-K, Ex 3(a)
3(b)	Composite By-Laws of AEP amended as of April 25, 2023.	Form 8-K, Ex 3(b) filed April 28, 2023
*†3(b)1	Amended By-Laws of AEP, as amended December 22, 2025 and effective July 1, 2026.	
4(a)	Indenture (for unsecured debt securities), dated as of May 1, 2001, between AEP and The Bank of New York, as Trustee.	Registration Statement No. 333-86050, Ex 4(a)(b)(c) Registration Statement No. 333-105532, Ex 4(d)(e)(f) Registration Statement No. 333-200956, Ex 4(b) Registration Statement No. 333-222068, Ex 4(b) Registration Statement No. 333-249918, Ex 4(b)(c) Registration Statement No. 333-275345, Ex 4(b)(c)(d)
4(a)1	Company Order and Officer's Certificate between AEP and The Bank of New York Mellon Trust Company, N.A. as Trustee dated December 8, 2023 establishing terms of the 5.20% Senior Notes, Series R due 2029.	Form 8-K, Ex. 4(a) filed December 8, 2023
4(b)	Junior Subordinated Indenture, dated March 1, 2008, between AEP and The Bank of New York Mellon Trust Company, N.A., as Trustee for the Junior Subordinated Debentures.	Registration Statement No. 333-156387, Ex 4(c)(d) Registration Statement No. 333-249918, Ex 4(f)(g)
4(b)1	Supplemental Indenture No. 6 between AEP and The Bank of New York Mellon Trust Company, N.A., as Trustee, dated June 20, 2024, establishing the terms of 7.050% Fixed-to-Fixed Reset Rate Junior Subordinated Debentures, Series A, due 2054 and the 6.950% Fixed-to-Fixed Reset Rate Junior Subordinated Debentures, Series B, due 2054.	Form 8-K Ex 4(a) filed June 20, 2024
4(b)2	Supplemental Indenture No. 7 between AEP and The Bank of New York Mellon Trust Company, N.A., as Trustee, dated September 25, 2025, establishing the terms of 5.80% Fixed-to-Fixed Reset Rate Junior Subordinated Debentures, Series C, due 2056 and the 6.050% Fixed-to-Fixed Reset Rate Junior Subordinated Debentures, Series D, due 2056.	Form 8-K Ex 4(a) filed September 23, 2025
4(b)3	Amended and Restated Supplemental Indenture No. 7 between AEP and The Bank of New York Mellon Trust Company, N.A., as Trustee, dated December 5, 2025, establishing the terms of 5.80% Fixed-to-Fixed Reset Rate Junior Subordinated Debentures, Series C, due 2056 and the 6.050% Fixed-to-Fixed Reset Rate Junior Subordinated Debentures, Series D, due 2056.	Form 8-K Ex 4(a) filed December 3, 2025

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(c)	$4,000,000,000 Credit Agreement dated March 31, 2021 among AEP, Initial Lenders and Wells Fargo Bank National Association as Administrative Agent.	Form 10-Q Ex 4.2, March 31, 2021
4(c)1	April 7, 2022 Amendment and extension to $4,000,000,000 Credit Agreement dated March 31, 2021 among AEP, Initial Lenders and Wells Fargo Bank National Association as Administrative Agent.	Form 10-Q Ex 4(a), March 31, 2022
4(c)2	March 28, 2024 Amendment and extension to $5,000,000,000 of the $4,000,000,000 Credit Agreement dated March 31, 2021 among AEP, Initial Lenders and Wells Fargo Bank National Association as Administrative Agent.	Form 10-Q Ex 4(d), March 31, 2024
4(d)	$1,000,000,000 Credit Agreement dated March 31, 2021 among AEP, Initial Lenders and Wells Fargo Bank National Association as Administrative Agent.	Form 10-Q Ex 4.3, March 31, 2021
4(d)1	April 7, 2022 Amendment and extension to $1,000,000,000 Credit Agreement dated March 31, 2021 among AEP, Initial Lenders and Wells Fargo Bank National Association as Administrative Agent.	Form 10-Q Ex 4(b), March 31, 2022
4(d)2	March 31, 2023 Amendment and extension to $1,000,000,000 Credit Agreement dated March 31, 2021 among AEP, Initial Lenders and Wells Fargo Bank National Association as Administrative Agent.	Form 10-Q Ex 4(b), March 31, 2023
4(d)3	March 28, 2024 Amendment and extension to $1,000,000,000 Credit Agreement dated March 31, 2021 among AEP, Initial Lenders and Wells Fargo Bank National Association as Administrative Agent.	Form 10-Q Ex 4(c), March 31, 2024
4(e)1	Distribution Agreement, dated November 25, 2025, among AEP and Barclays Capital Inc., BofA Securities, Inc., Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Mizuho Securities USA LLC, MUFG Securities Americas Inc., Scotia Capital (USA) Inc., Wells Fargo Securities LLC, Barclays Bank PLC, Bank of America, N.A., Citibank N.A, J.P. Morgan Chase Bank, National Association, Mizuho Markets Americas LLC, MUFG Securities EMEA plc, The Bank of Nova Scotia and Wells Fargo Bank, National Association.	Form 8-K Ex 1.1 filed November 25, 2025
4(f)	Description of Securities.	2020 Form 10-K, Ex 4(c)
10(a)	Consent Decree with U.S. District Court dated October 9, 2007, as modified July 17, 2019.	Form 8-K, Ex. 10 filed October 9, 2007 Form 10-Q, Ex 10, June 30, 2013 Form 10-Q, Ex 10, June 30, 2019
†10(b)	AEP Retainer Deferral Plan for Non-Employee Directors, as Amended and Restated effective October 1, 2020.	Form 10-Q, Ex 10.2, September 30, 2020
†10(c)	AEP Stock Unit Accumulation Plan for Non-Employee Directors as amended October 1, 2020.	Form 10-Q, Ex 10.3, September 30, 2020

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(c)1	AEP Stock Unit Accumulation Plan for Non-Employee Directors as amended June 1, 2022.	2021 Form 10-K, Ex 10(d)1
†10(d)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2020.	2019 Form 10-K, Ex 10(e)
†10(d)1	Guaranty by AEP of AEPSC Excess Benefits Plan.	1990 Form 10-K, Ex 10(h)(1)(B)
†10(e)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of October 6, 2021 (Non-Qualified).	2022 Form 10-K, Ex 10(e)
†10(f)	AEPSC Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3)
†10(f)1A	First Amendment to AEPSC Umbrella Trust for Executives.	2008 Form 10-K, Ex 10(l)(3)(A)
†10(f)2A	Second Amendment to AEPSC Umbrella Trust for Executives.	2018 Form 10-K, Ex 10(g)(2)(A)
†10(g)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of June 1, 2019.	Form 10-Q, Ex 10(1), September 30, 2019
†10(h)	AEP Change In Control Agreement, as Revised Effective January 1, 2017.	Form 10-Q, Ex 10(c), September 30, 2016
†10(i)	AEP System Long-Term Incentive Plan effective as of April 23, 2024	Form 10-Q Ex 10(c), March 31, 2024
†10(i)1A	Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	Form 10-Q, Ex 10(a), March 30, 2018
†10(i)2A	Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan as Amended and Restated effective January 1, 2022.	2022 Form 10-K, Ex 10(i)2A
†10(j)	AEP System Stock Ownership Requirement Plan Amended and Restated effective October 1, 2020.	Form 10-Q, Ex 10.1, September 30, 2020
†10(k)	Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2020.	2019 Form 10-K, Ex 10(l)
†10(l)	AEP Executive Severance Plan Amended and Restated effective July 15, 2024.	Form 10-Q Ex 10(a), June 30, 2024
*†10(l)(1)	First Amendment to the AEP Executive Severance Plan effective February 17, 2025.	
†10(m)	AEP Aircraft Timesharing Agreement dated July 16, 2024 between AEPSC and William J. Fehrman.	Form 10-Q Ex 10(a), September 30, 2024
†10(m)(1)	AEP Amended and Restated Aircraft Time Sharing Agreement dated May 5, 2025 between AEPSC and William J. Fehrman.	Form 10-Q Ex 10(a), March 31, 2025
*†10(n)	AEP Board Observer Agreement effective December 22, 2025.	
10(o)	Confirmation of Forward Sale Transaction, dated March 24, 2025, between AEP and Citibank, N.A. in capacity as a Forward Purchase.	Form 8-K, Ex 10.1 filed March 26, 2025

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(o)(1)	Confirmation of Forward Sale Transaction, dated March 24, 2025, between AEP and Barclays Bank PLC in capacity as a Forward Purchase.	Form 8-K, Ex 10.2 filed March 26, 2025
10(o)(2)	Confirmation of Forward Sale Transaction, dated March 25, 2025, between AEP and Citibank, N.A. in capacity as a Forward Purchase.	Form 8-K, Ex 10.3 filed March 26, 2025
10(o)(3)	Confirmation of Forward Sale Transaction, dated March 25, 2025, between AEP and Barclays Bank PLC in capacity as a Forward Purchase.	Form 8-K, Ex 10.4 filed March 26, 2025
*†10(p)	Severance, Release of All Claims, and Non-Competition Agreement by and between AEP and David M. Feinberg.	
19.1	AEP Insider Trading Policy.	2024 Form 10-K, Ex 19
*21	List of subsidiaries of AEP.	
*23	Consent of PricewaterhouseCoopers LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
97	AEP Policy on Recouping Incentive Compensation	2023 Form-10-K, Ex 97
101.INS	XBRL Instance Document. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	
AEP TEXAS‡ File No. 333-221643		
3(a)	Composite of the Restated Certificate of Incorporation, as amended.	Registration Statement No. 333-221643, Ex 3(a)
3(b)	Bylaws.	Registration Statement No. 333-221643, Ex 3(b)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(a)	Indenture, dated as of September 1, 2017, between AEP Texas and The Bank of New York Mellon Trust Company, N.A., as Trustee.	Registration Statement No. 333-221643, Ex 4(a)-1,4(a)-2 Registration Statement No. 333-228657, Ex 4(a)-4,4(a)-5 Registration Statement No. 333-230613, Ex 4(a)(b) Registration Statement No. 333-253585, Ex 4(b)(c)(d) Registration Statement No. 333-279418 Ex 4(b)(c)(d)
4(b)	Company Order and Officer's Certificate between AEP Texas and The Bank of New York Mellon Trust Company, N.A., as Trustee dated May 22, 2024, establishing terms of the 5.45% Senior Notes, Series N due 2029 and 5.70% Senior Notes, Series O due 2034.	Form 8-K, Ex 4(a) filed May 22, 2024
4(b)(1)	Company Order and Officer's Certificate between AEP Texas and The Bank of New York Mellon Trust Company, N.A., as Trustee dated September 24, 2025, establishing terms of the 5.70% Senior Notes, Series O due 2034 and 5.85% Senior Notes, Series P due 2055.	Form 8-K, Ex 4(a) filed September 22, 2025
*23	Consent of PricewaterhouseCoopers LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	
AEPTCo‡ File No. 333-217143		
3(a)	Limited Liability Company Agreement of AEP Transmission Company, LLC dated as of January 27, 2006.	Registration Statement No. 333-217143, Ex 3(a)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
3(b)	First Amendment to Limited Liability Company Agreement of AEPTCo dated as of May 21, 2013.	Registration Statement No. 333-217143, Ex 3(b)
4(a)	Indenture, dated as of November 1, 2016, between AEPTCo and The Bank of New York Mellon Trust Company, N.A., as Trustee.	Registration Statement No. 333-217143, Ex 4(a)-1, 4(a)-2 Registration Statement No. 333-225325, Ex 4(b)(c)(d) Registration Statement No. 333-255605, Ex 4(b)(c)(d)(e) Registration Statement No. 333-277662 Ex 4(b)(c)(d)
4(b)	Company Order and Officer's Certificate between AEPTCo and The Bank of New York Mellon Trust Company, N.A., as Trustee, dated March 13, 2024 establishing terms of the 5.15% Senior Notes, Series Q due 2034.	Form 8-K Ex 4(a) filed March 13, 2024
4(b)(1)	Company Order and Officer's Certificate between AEPTCo and The Bank of New York Mellon Trust Company, N.A., as Trustee, dated May 14, 2025, establishing terms of the Note.	Form 8-K, Ex 4(a) filed May 12, 2025
4(c)	Note Purchase Agreement, dated as of October 18, 2012 between AEPTCo and the Initial Purchasers.	Registration Statement No. 333-217143, Ex 4(c)-1
4(c)1	Supplement to Note Purchase Agreement, dated as of November 7, 2013 between AEPTCo and the Initial Purchasers.	Registration Statement No. 333-217143, Ex 4(c)-2
4(c)2	Supplement to Note Purchase Agreement, dated as of November 14, 2014 between AEP Transmission Company, LLC and the Initial Purchasers.	Registration Statement No. 333-217143, Ex 4(c)-3
4(d)	Note Purchase Agreement, dated October 15, 2025, by and among AEPTCo, the Secretary of Energy acting through the U.S. Department of Energy and the Federal Financing Bank.	Form 8-K, Ex 10.1 filed October 15, 2025
4(e)	Future Advance Promissory Note of AEPTCo dated October 15, 2025.	Form 8-K, Ex 10.2 filed October 15, 2025
10(a)	Stock Purchase Agreement dated as of October 26, 2021 among AEP, AEPTCo and Liberty Utilities Co.	Form 10-Q, Ex 10, September 30, 2021
10(a)1	First Amendment to Stock Purchase Agreement dated September 29, 2022 among AEP, AEPTCo and Liberty Utilities Co.	Form 10-Q, Ex 10, September 30, 2022
10(a)2	Second Amendment to Stock Purchase Agreement dated January 16, 2023 among AEP, AEPTCo and Liberty Utilities Co.	2023 Form 10-K, Ex 10(2)A
10(a)3	Mutual Termination Agreement dated and effective April 17, 2023 among AEP, AEPTCo and Liberty Utilities Co. terminating the Stock Purchase Agreement dated October 26, 2021 the First Amendment to the Stock Purchase Agreement, dated as of September 29, 2022, and the Second Amendment to the Stock Purchase Agreement, dated as of January 16, 2023.	Form 10-Q, Ex 10, June 30, 2023
10(b)	Contribution Agreement by and among AEPTCo, Midwest Transmission Company, LLC and Olympus BidCo L.P. dated as of January 9, 2025.	2024 Form 10-K, Ex 10(b)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(b)(1)	Amended and Restated Limited Liability Company Agreement, dated June 5, 2025, among AEPTCo, Midwest Transmission Holdings, LLC and Olympus BidCo L.P.	Form 10-Q, Ex 10(a), June 30, 2025
10(c)	Loan Guarantee Agreement, dated October 15, 2025, by and between AEPTCo and the U.S. Department of Energy.	Form 8-K, Ex 10.3 filed October 15, 2025
*23	Consent of PricewaterhouseCoopers LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	
APCo‡ File No. 1-3457		
3(a)	Composite of the Restated Articles of Incorporation of APCo, amended as of March 7, 1997.	1996 Form 10-K, Ex 3(d)
3(b)	Composite By-Laws of APCo, amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(a)	Indenture (for unsecured debt securities), dated as of January 1, 1998, between APCo and The Bank of New York, As Trustee.	Registration Statement No. 333-45927, Ex 4(a)(b) Registration Statement No. 333-49071, Ex 4(b) Registration Statement No. 333-84061, Ex 4(b)(c) Registration Statement No. 333-100451, Ex 4(b) Registration Statement No. 333-116284, Ex 4(b)(c) Registration Statement No. 333-123348, Ex 4(b)(c) Registration Statement No. 333-136432, Ex 4(b)(c)(d) Registration Statement No. 333-161940, Ex 4(b)(c)(d) Registration Statement No. 333-182336, Ex 4(b)(c) Registration Statement No. 333-200750, Ex 4(b)(c) Registration Statement No. 333-214448, Ex 4(b) Registration Statement No. 333-236613, Ex 4(b)(c) Registration Statement No. 333-268874, Ex 4(b)(c)(d)(e) Registration Statement No. 333-290611, Ex 4(b)
4(b)	Company Order and Officer's Certificate between APCo and The Bank of New York Mellon Trust Company, N.A., as Trustee, dated March 20, 2024 establishing terms of the 5.65% Senior Notes, Series CC due 2034.	Form 8-K Ex 4(a) filed March 20, 2024
10(a)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended September 10, 2010.	2013 Form 10-K, Ex 10(a)
10(b)	Consent Decree with U.S. District Court dated October 9, 2007, as modified July 17, 2019.	Form 8-K, Ex. 10 filed October 9, 2007 Form 10-Q, Ex 10, June 30, 2013 Form 10-Q, Ex 10, June 30, 2019
*23	Consent of PricewaterhouseCoopers LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
I&M‡ File No. 1-3570		
3(a)	Composite of the Amended Articles of Acceptance of I&M, dated of March 7, 1997.	1996 Form 10-K, Ex 3(c)
3(b)	Composite By-Laws of I&M, amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4	Indenture (for unsecured debt securities), dated as of October 1, 1998, between I&M and The Bank of New York, as Trustee.	Registration Statement No. 333-88523, Ex 4(a)(b)(c) Registration Statement No. 333-58656, Ex 4(b)(c) Registration Statement No. 333-108975, Ex 4(b)(c)(d) Registration Statement No. 333-136538, Ex 4(b)(c) Registration Statement No. 333-156182, Ex 4(b) Registration Statement No. 333-185087, Ex 4(b) Registration Statement No. 333-207836, Ex 4(b) Registration Statement No. 333-225103, Ex 4(b)(c)(d) Registration Statement No. 333-268880, Ex 4(b)(c) Registration Statement No. 333-290612, Ex 4(b)
4(a)	Company Order and Officer's Certificate between I&M and The Bank of New York Mellon Trust Company, N.A., as Trustee, dated March 23, 2023 establishing terms of the 5.625% Senior Notes, Series P, due 2053.	Form 8-K, Ex 4(a) filed March 23, 2023
10(a)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended September 10, 2010.	2013 Form 10-K, Ex 10(a)
10(b)	Unit Power Agreement dated as of March 31, 1982 between AEGCo and I&M, as amended.	Registration Statement No. 33-32752, Ex 28(b)(1)(A)(B)
10(c)	Consent Decree with U.S. District Court dated October 9, 2007, as modified July 17, 2019.	Form 8-K, Ex. 10 filed October 9, 2007 Form 10-Q, Ex 10, June 30, 2013 Form 10-Q, Ex 10, June 30, 2019
*23	Consent of PricewaterhouseCoopers LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	
OPCo‡ File No. 1-6543		
3(a)	Composite of the Amended Articles of Incorporation of OPCo, dated June 3, 2002.	Form 10-Q, Ex 3(e), June 30, 2002
3(b)	Amended Code of Regulations of OPCo.	Form 10-Q, Ex 3(b), June 30, 2008
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between OPCo and Bankers Trust Company (now The Bank of New York Mellon Trust Company, N.A. as assignee of Deutsche Bank Trust Company Americas), as Trustee.	Registration Statement No. 333-49595, Ex 4(a)(b)(c) Registration Statement No. 333-106242, Ex 4(b)(c)(d) Registration Statement No. 333-127913, Ex 4(b)(c) Registration Statement No. 333-139802, Ex 4(b)(c)(d) Registration Statement No. 333-161537, Ex 4(b)(c)(d) Registration Statement No. 333-211192, Ex 4(b) Registration Statement No. 333-230094, Ex 4(b) Registration Statement No. 333-255600, Ex 4(b)(c)(d) Registration Statement No. 333-275801, Ex 4(b)
4(a)1	Resignation of Deutsche Bank Trust Company Americas, as Trustee and appointment of The Bank of New York Mellon Trust Company, N.A. as Trustee of Indenture with OPCo dated as of September 1, 1997.	Form 8-K, Item 8.01 filed October 8, 2018
4(a)2	Company Order and Officer's Certificate between OPCo and The Bank of New York Mellon Trust Company, N.A. as Trustee dated September 9, 2021 establishing terms of the 2.90% Senior Notes, Series R, due 2051.	Form 8-K, Ex 4(a) filed September 13, 2021
4(a)3	Company Order and Officer's Certificate between OPCo and The Bank of New York Mellon Trust Company, N.A. as Trustee dated May 6, 2024 establishing terms of the 5.65% Senior Notes, Series T due 2034.	Form 8-K, Ex 4(a) filed May 6, 2024
4(b)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee.	Registration Statement No. 333-127913, Ex 4(d)(e)(f)
4(c)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo (predecessor in interest to OPCo) and Bankers Trust Company, as Trustee.	Registration Statement No. 333-54025, Ex 4(a)(b)(c)(d) Registration Statement No. 333-128174, Ex 4(b)(c)(d) Registration Statement No. 333-150603, Ex 4(b)
4(d)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between CSPCo (predecessor in interest to OPCo) and Bank One, N.A., as Trustee.	Registration Statement No. 333-128174, Ex 4(e)(f)(g) Registration Statement No. 333-150603, Ex 4(b)
4(e)	First Supplemental Indenture, dated as of December 31, 2011, by and between OPCo and The Bank of New York Mellon Trust Company, N.A., as trustee, supplementing the Indenture dated as of September 1, 1997 between CSPCo (predecessor in interest to OPCo) and the trustee.	Form 8-K, Ex 4.1 filed January 6, 2012

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(f)	Third Supplemental Indenture, dated as of December 31, 2011, by and between OPCo and The Bank of New York Mellon Trust Company, N.A., as trustee, supplementing the Indenture dated as of February 14, 2003 between CSPCo (predecessor in interest to OPCo) and the trustee.	Form 8-K, Ex 4.2 filed January 6, 2012
10(a)	Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended September 10, 2010.	2013 Form 10-K, Ex 10(a)
10(b)	Consent Decree with U.S. District Court dated October 9, 2007, as modified July 17, 2019.	Form 8-K, Ex. 10 filed October 9, 2007 Form 10-Q, Ex 10, June 30, 2013 Form 10-Q, Ex 10, June 30, 2019
*23	Consent of PricewaterhouseCoopers LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	
PSO‡ File No. 0-343		
3(a)	Certificate of Amendment to Restated Certificate of Incorporation of PSO.	Form 10-Q, Ex 3(a), June 30, 2008
3(b)	Composite By-Laws of PSO amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee.	Registration Statement No. 333-100623, Ex 4(a)(b) Registration Statement No. 333-114665, Ex 4(b)(c) Registration Statement No. 333-133548, Ex 4(b)(c) Registration Statement No. 333-156319, Ex 4(b)(c) Registration Statement No. 333-251378, Ex 4(b)(c) Registration Statement No. 333-282058 Ex. 4(b)(c)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(b)	Twelfth Supplemental Indenture dated as of December 1, 2024 between PSO and The Bank of New York Mellon Trust Company, N.A. as Trustee establishing terms of the 5.20% Senior Notes, Series M, due 2035.	Form 8-K. Ex 4(a) filed December 5, 2024
4(b)(1)	Thirteenth Supplemental Indenture dated June 1, 2025, between PSO and The Bank of New York Mellon Trust Company, N.A., as Trustee, establishing terms of the Notes.	Form 8-K, Ex 4(a) filed June 23, 2025
4(c)	Credit Agreement dated as of January 19, 2021 among PSO as Borrower, Initial Lenders and Sumitomo Mitsui Banking Corporation as Administrative Agent.	2020 Form 10-K, Ex 4(d)
4(c)A	April 19, 2022 Amendment and extension to $500,000,000 Credit Agreement dated January 19, 2021 among PSO, Initial Lenders and Sumitomo Mitsui Banking Corporation as Administrative Agent.	Form 10-Q Ex 4(c), March 31, 2022
*23	Consent of PricewaterhouseCoopers LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	
SWEPCo‡ File No. 1-3146		
3(a)	Composite of Amended Restated Certificate of Incorporation of SWEPCo.	2008 Form 10-K, Ex 3(a)
3(a)(A)	Amendment to Amended Restated Certificate of Incorporation.	Form 8-K Ex 3.1 filed September 1, 2020

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
3(b)	Composite By-Laws of SWEPCo amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCo and The Bank of New York, as Trustee.	Registration Statement No. 333-96213 Registration Statement No. 333-87834, Ex 4(a)(b) Registration Statement No. 333-100632, Ex 4(b) Registration Statement No. 333-108045, Ex 4(b) Registration Statement No. 333-145669, Ex 4(c)(d) Registration Statement No. 333-161539, Ex 4(b)(c) Registration Statement No. 333-194991, Ex 4(b)(c) Registration Statement No. 333-208535, Ex 4(b)(c) Registration Statement No. 333-226856, Ex 4(b)(c) Registration Statement No. 333-238159, Ex 4(b) Registration Statement No. 333-258961, Ex 4(b) Registration Statement No. 333-282060, Ex 4(b)(c)
*23	Consent of PricewaterhouseCoopers LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	

‡ Certain instruments defining the rights of holders of long-term debt of the registrants included in the financial statements of registrants filed herewith have been omitted because the total amount of securities authorized thereunder does not exceed 10% of the total assets of registrants. The registrants hereby agree to furnish a copy of any such omitted instrument to the SEC upon request.

The agreements and other documents filed as exhibits to this report are not intended to provide factual information or other disclosure other than with respect to the terms of the agreements or other documents themselves, and you should not rely on them for that purpose. In particular, any representations and warranties made by AEP in these agreements or other documents were made solely within the specific context of the relevant agreement or document and may not describe the actual state of affairs as of the date they were made or at any other time.

AMERICAN ELECTRIC POWER COMPANY, INC.

(Formerly American Gas & Electric Company)

BY-LAWS

As Amended July 1, 2026

AMERICAN ELECTRIC POWER COMPANY, INC.

(Formerly American Gas and Electric Company)

BY-LAWS

Section 1. The annual meeting of the stockholders of the Company shall be held on the fourth Tuesday of April in each year, or on such other date as determined by the Board of Directors, at an hour and place within or without the State of New York designated by the Board of Directors. (As amended September 25, 2012.)

Section 2. Special meetings of the stockholders of the Company may be held upon call of the Board of Directors or of the Executive Committee, or of stockholders holding one-fourth of the capital stock, at such time and at such place within or without the State of New York as may be stated in the call and notice. (As amended July 26, 1989.)

Section 3. Notice of time and place of every meeting of stockholders shall be mailed at least ten days previous thereto to each stockholder of record who shall have furnished a written address to the Secretary of the Company for the purpose. Such further notice shall be given as may be required by law. But meetings may be held without notice if all stockholders are present, or if notice is waived by those not present.

Section 4. Except as otherwise provided by law, the holders of a majority of the outstanding capital stock of the Company entitled to vote at any meeting of the stockholders of the Company must be present in person or by proxy at such meeting of the stockholders of the Company to constitute a quorum. If, however, such majority shall not be represented at any meeting of the stockholders of the Company regularly called, the holders of a majority of the shares present or represented and entitled to vote thereat shall have power to adjourn such meeting to another time without notice other than announcement of adjournment at the meeting, and there may be successive adjournments for like cause and in like manner until the requisite amount of shares entitled to vote at such meeting shall be represented. (As amended May 20, 1952.)

Section 5. The Board of Directors or the Executive Committee shall appoint two inspectors of stockholders' votes and elections to serve until the final adjournment of the annual stockholders' meeting. If they fail to make such appointment, or if their appointees, or any of them, fail to appear at any meeting of stockholders, the Chair of the meeting may appoint inspectors, or an inspector, to act at that meeting. (As amended December 7, 2021.)

Section 6. Meetings of the stockholders shall be presided over by the Chair of the Board, or the President, or, if neither the Chair of the Board nor the President is present, by a Vice President, and in his/her absence, by a Chair to be elected at the meeting. The Secretary of the Company shall act as Secretary of such meetings, if present. (As amended December 7, 2021.)

Section 7. The Board of Directors shall consist of such number of directors, not less than nine (9) nor more than seventeen (17), as shall be determined from time to time as herein provided. Directors shall be elected at each annual meeting of stockholders and each director so elected shall hold office until the next annual meeting of stockholders and until his/her successor is elected and qualified. The number of directors to be elected at any annual meeting of stockholders shall, except as otherwise provided herein, be the number fixed in the latest resolution of the Board of Directors adopted pursuant to the authority contained in the next succeeding sentence and not subsequently rescinded. The Board of Directors shall have power from time to time and at any time when the stockholders are not assembled as such in an annual or special meeting, by resolution adopted by a majority of the directors then in office, or such greater number required by law, to fix, within the limits prescribed by this Section 7, the number of directors of the Company. If the number of directors is increased, the additional directors may, to the extent permitted by law, be elected by a majority of the directors in office at the time of the increase, or, if not so elected prior to the next annual meeting of stockholders, such additional directors shall be elected at such annual meeting. If the number of directors is decreased, then to the extent that the decrease does not exceed the number of vacancies in the Board then existing, such resolution may provide that it shall become effective forthwith, and to the extent that the decrease exceeds such number of vacancies such resolution shall provide that it shall not become effective until the next election of directors by the stockholders. If the Board of Directors shall fail to adopt a resolution which fixes initially the number of directors, the number of directors shall be twelve (12). If, after the number of directors shall have been fixed by such resolution, such resolution shall cease to be in effect other than by being superseded by another such resolution, or it shall become necessary that the number of directors be fixed by these By-Laws, the number of directors shall be that number specified in the latest of such resolutions, whether or not such resolution continues in effect. (As amended September 25, 2012.)

Section 8. Vacancies in the Board of Directors may be filled by the Board at any meeting.

Section 9. Meetings of the Board of Directors shall be held at times fixed by resolution of the Board, or upon the call of the Executive Committee, the Chair of the Board, the President or the Lead Director and the Secretary or officer performing his/her duties shall give reasonable notice of all meetings of directors; provided, that a meeting may be held without notice immediately after the annual election at the same place, and notice need not be given of regular meetings held at times fixed by resolution of the Board. Meetings may be held at any time without notice if all the directors are present, or if those not present waive notice either before or after the meeting. A majority of the Board of Directors shall constitute a quorum for the transaction of business. Any one or more members of the Board or of any committee thereof may participate in a meeting of the Board or such committee by means of a conference telephone or similar communications equipment allowing all persons participating in the meeting to hear each other at the same time. Participation by such means constitutes presence in person at a meeting. (As amended December 7, 2021.)

Section 10. The Board of Directors, by resolution adopted by a majority of the entire Board, may designate among its members an Executive Committee and one or more other committees, each consisting of two (2) or more directors, and each of which, to the extent provided in such resolution, shall have all the authority of the Board. However, no such committee shall have authority as to any of the following matters:

(a) The submission to stockholders of any action as to which stockholders' authorization is required by law;

(b) The filling of vacancies in the Board of Directors or in any committee;

(c) The fixing of compensation of any director for serving on the Board or on any committee;

(d) The amendment or repeal of these By-Laws or the adoption of new By-Laws; or

(e) The amendment or repeal of any resolution of the Board which by its terms shall not be so amendable or repealable.

The Board of Directors shall have the power at any time to increase or decrease the number of members of any committee (provided that no such decrease shall reduce the number of members to less than two), to fill vacancies on it, to remove any member of it, and to change its functions or terminate its existence. Each committee may make such rules for the conduct of its business as it may deem necessary. A majority of the members of a committee shall constitute a quorum.
(As amended December 6, 2022.)

Section 11. The Board of Directors, as soon as may be after the election each year, shall appoint one of their number Chair of the Board and appoint a President of the Company, and shall appoint one or more Vice Presidents, a Secretary and a Treasurer, and from time to time shall appoint such other officers as they deem proper. If the Chair of the Board is not an independent director, the independent members of the Board of Directors shall also appoint one of their number Lead Director. The same person may be appointed to more than one office. (As amended December 7, 2021.)

Section 12. The term of office of all officers shall be one year, or until their respective successors are elected but any officer may be removed from office at any time by the Board of Directors, unless otherwise agreed by agreement in writing duly authorized by the Board of Directors. (As amended December 15, 2003.)

Section 13. The officers of the Company shall have such powers and duties as generally pertain to their offices, respectively, as well as such powers and duties as from time to time shall be conferred by the Board of Directors or the Executive Committee.

Section 14. The shares of stock of the Company shall be represented by a certificate or shall be uncertificated shares as provided for under New York law. Shares in the capital stock of the Company shall be transferred or assigned on the books of the Company only upon (i) surrender to the Company or its transfer agent of a certificate representing shares, duly endorsed or accompanied by proper evidence of succession, assignation, or authority to transfer, with such proof of the authenticity of the signature as the Company or its agents may reasonably require in the case of shares evidenced by a certificate or certificates or (ii) receipt of transfer instructions from the registered owner of uncertificated shares reasonably acceptable to the Company and its agents. (As amended December 12, 2007.)

Section 15. To the fullest extent permitted by law, the Company shall indemnify any person made, or threatened to be made, a party to any action or proceeding (formal or informal), whether civil, criminal, administrative or investigative and whether by or in the right of the Company or otherwise, by reason of the fact that such person, such person's testator or intestate, is or was a director, officer or employee of the Company, or of any subsidiary or affiliate of the Company, or served any other corporation, partnership, joint venture, trust, employee benefit plan or other enterprise in any capacity at the request of the Company, against all loss and expense including, without limiting the generality of the foregoing, judgments, fines (including excise taxes), amounts paid in settlement and attorneys' fees and disbursements actually and necessarily incurred as a result of such action or proceeding, or any appeal therefrom, and all legal fees and expenses incurred in successfully asserting a claim for indemnification pursuant to this Section 15; provided, however, that no indemnification may be made to or on behalf of any director, officer or employee if a judgment or other final adjudication adverse to the director, officer or employee establishes that such person's acts were committed in bad faith or were the result of active and deliberate dishonesty and were material to the cause of action so adjudicated, or that such person personally gained in fact a financial profit or other advantage to which such person was not legally entitled.

In any case in which a director, officer or employee of the Company (or a representative of the estate of such director, officer or employee) requests indemnification, upon such person's request the Board of Directors shall meet within sixty days thereof to determine whether such person is eligible for indemnification in accordance with the standard set forth above. Such a person claiming indemnification shall be entitled to indemnification upon a determination that no judgment or other final adjudication adverse to such person has established that such person's acts were committed in bad faith or were the result of active and deliberate dishonesty and were material to the cause of action so adjudicated, or that such person personally gained in fact a financial profit or other advantage to which such person was not legally entitled. Such determination shall be made:

(a) by the Board of Directors acting by a quorum consisting of directors who are not parties to the action or proceeding in respect of which indemnification is sought; or

(b) if such quorum is unobtainable or if directed by such quorum, then by either (i) the Board of Directors upon the opinion in writing of independent legal counsel that indemnification is proper in the circumstances because such person is eligible for indemnification in accordance with the standard set forth above, or (ii) by the stockholders upon a finding that such person is eligible for indemnification in accordance with the standard set forth above. Notwithstanding the foregoing, a determination of eligibility for indemnification may be made in any manner permitted by law.

To the fullest extent permitted by law, the Company shall promptly advance to any person made, or threatened to be made, a party to any action or proceeding (formal or informal), whether civil, criminal, administrative or investigative and whether by or in the right of the Company or otherwise, by reason of the fact that such person, such person's testator or intestate, is or was a director, officer or employee of the Company, or of any subsidiary or affiliate of the Company, or served any other corporation or any partnership, joint venture, trust, employee benefit plan or

other enterprise in any capacity at the request of the Company, expenses incurred in defending such actions or proceedings, upon request of such person and receipt of an undertaking by or on behalf of such director, officer or employee to repay amounts advanced to the extent that it is ultimately determined that such person was not eligible for indemnification in accordance with the standard set forth above.

The foregoing provisions of this Section 15 shall be deemed to be a contract between the Company and each director, officer or employee of the Company, or its subsidiaries or affiliates, and any modification or repeal of this Section 15 or such provisions of the New York Business Corporation Law shall not diminish any rights or obligations existing prior to such modification or repeal with respect to any action or proceeding theretofore or thereafter brought; provided, however, that the right of indemnification provided in this Section 15 shall not be deemed exclusive of any other rights to which any director, officer or employee of the Company may now be or hereafter become entitled apart from this Section 15, under any applicable law including the New York Business Corporation Law. Irrespective of the provisions of this Section 15, the Board of Directors may, at any time or from time to time, approve indemnification of directors, officers, employees or agents to the full extent permitted by the New York Business Corporation Law at the time in effect, whether on account of past or future actions or transactions. Notwithstanding the foregoing, the Company shall enter into such additional contracts providing for indemnification and advancement of expenses with directors, officers or employees of the Company or its subsidiaries or affiliates as the Board of Directors shall authorize, provided that the terms of any such contract shall be consistent with the provisions of the New York Business Corporation Law.

As used in this Section 15, the term "employee" shall include, without limitation, any employee, including any professionally licensed employee, of the Company. Such term shall also include, without limitation, any employee, including any professionally licensed employee, of a subsidiary or affiliate of the Company who is acting on behalf of the Company.

The indemnification provided by this Section 15 shall be limited with respect to directors, officers and controlling persons to the extent provided in any undertaking entered into by the Company or its subsidiaries or affiliates, as required by the Securities and Exchange Commission pursuant to any rule or regulation of the Securities and Exchange Commission now or hereafter in effect.

If any action with respect to indemnification of directors or officers is taken by way of amendment to these By-Laws, resolution of the Board of Directors, or by agreement, then the Company shall give such notice to the stockholders as is required by law.

The Company may purchase and maintain insurance on behalf of any person described in this Section 15 against any liability which may be asserted against such person whether or not the Company would have the power to indemnify such person against such liability under the provisions of this Section 15 or otherwise.

If any provision of this Section 15 shall be found to be invalid or limited in application by reason of any law, regulation or proceeding, it shall not affect any other provision or the validity of the remaining provisions hereof.

The provisions of this Section 15 shall be applicable to claims, actions, suits or proceedings made, commenced or pending after the adoption hereof, whether arising from acts or omissions to act occurring before or after the adoption hereof. (As amended October 29, 1986.)

Section 16. These By-Laws may be amended or added to at any meeting of the Board of Directors by affirmative vote of a majority of all of the directors, if notice of the proposed change has been delivered or mailed to the directors five days before the meeting, or if all the directors are present, or if all not present assent in writing to such change; provided, however, that the provisions of Section 7 may be amended only by the affirmative vote, in person or by proxy, of the holders of a majority of the outstanding shares of capital stock entitled to vote at any meeting of the stockholders of the Company; and provided further, in the event of any such amendment or addition pursuant to vote by the stockholders of the Company, that such amendment or addition, or a summary thereof, shall have been set forth or referred to in the notice of such meeting. (As renumbered and amended October 29, 1986 and further amended April 25, 2023.)

Section 17. Each holder of common stock shall have one vote for every share of common stock entitled to vote which is registered in his or her name on the record date for the meeting. In cases where the number of nominees is less than or equal to the number of directors to be elected, each director to be elected by stockholders shall be elected by the vote of the majority of the votes cast at any meeting for the election of directors at which a quorum is present. For purposes of this Section 17, a majority of votes cast shall mean that the number of votes cast "for" a director's election exceeds 50% of the total number of votes cast with respect to that director's election. Votes cast shall include votes "for," "against" or to withhold authority in each case and exclude abstentions with respect to that director's election. In cases where the number of nominees exceeds the number of directors to be elected, each director to be elected by stockholders shall be elected by the vote of a plurality of the votes cast at any meeting for the election of directors at which a quorum is present.

If a nominee for director who is an incumbent director is not elected at a meeting of stockholders and no successor has been elected at the meeting, the director shall tender his or her resignation to the Board of Directors promptly after the certification of the election results by the inspector of elections. The Nominating, Governance & Compensation Committee shall make a recommendation to the Board of Directors whether or not to accept the tendered resignation. The Board of Directors shall make the decision whether or not to accept the tendered resignation, taking into account the Nominating, Governance & Compensation Committee's recommendation. The Board's decision about the tendered resignation, and the rationale behind the decision, shall be disclosed in a public announcement within 90 days after the date of the certification of the election results by the inspector of elections. The Nominating, Governance & Compensation Committee in making its recommendation, and the Board of Directors in making the decision, may consider any factors or other information that they consider appropriate and relevant. The director who tenders his or her resignation shall not participate in the recommendation of the Nominating, Governance & Compensation Committee or the decision of the Board of Directors about his or her resignation. If the incumbent director's resignation is not accepted by the Board of Directors, such director shall continue to serve until the next annual meeting and until his or her successor is duly elected, or his or her earlier resignation or removal. If a director's resignation is accepted by the Board of Directors pursuant to this By-Law, or if a nominee for director is not elected and the nominee is not

an incumbent director, then the Board of Directors, in its sole discretion, may fill any resulting vacancy pursuant to the provisions of Sections 7 and 8 or may decrease the size of the Board of Directors pursuant to the provisions of Section 7. (As amended July 1, 2026.)

Section 18. (A) Annual Meetings of Stockholders. (1) Nominations of persons for election to the Board and the proposal of other business to be considered by the stockholders may be made at an annual meeting of stockholders only (a) pursuant to the Company's notice of meeting (or any supplement thereto) delivered pursuant to Section 3 of these By-Laws, (b) by or at the direction of the Board or any authorized committee thereof or (c) by any stockholder of the Company who is entitled to vote on such election or such other business at the meeting, who complied with the notice procedures set forth in subparagraphs (2), (3) and (4) of this paragraph (A) of this Section 18 and who was a stockholder of record at the time such notice was delivered to the Secretary of the Company.

(2) For nominations or other business to be properly brought before an annual meeting by a stockholder, the stockholder must have given timely notice thereof in proper written form to the Secretary of the Company, and, in the case of business other than nominations of persons for election to the Board, such other business must be a proper matter for stockholder action. To be timely, a stockholder's notice shall be delivered to the Secretary at the principal executive offices of the Company not less than ninety (90) days nor more than one hundred twenty (120) days prior to the first anniversary of the preceding year's annual meeting; provided, however, that in the event that the date of the annual meeting is advanced by more than thirty (30) days, or delayed by more than seventy (70) days, from such anniversary date, notice by the stockholder to be timely must be so delivered not earlier than the close of business on the 120th day prior to such annual meeting and not later than the close of business on the later of the 90th day prior to such annual meeting or the tenth day following the day on which public announcement of the date of such meeting is first made. For purposes of the application of Rule 14a-4(c) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") (or any successor provision), the date for notice specified in this paragraph (A)(2) shall be the earlier of the date calculated as hereinbefore provided or the date specified in paragraph (c)(1) of Rule 14a-4.

(3) To be in proper written form, a stockholder's notice to the Secretary must set forth the following information:

(a) as to each person whom the stockholder proposes to nominate for election or re-election as a director (i) the name, age, business address and residence address of such person; (ii) the principal occupation or employment of such person; (iii) the class or series and number of all shares of stock of the Company which are owned beneficially or of record by such person and any affiliates or associates of such person, and the name of each nominee holder of shares of all stock of the Company owned beneficially but not of record by such person or any affiliates or associates of such person, and the number of such shares of stock of the Company held by each such nominee holder; (iv) whether and the extent to which any derivative instrument, swap, option, warrant, short interest, hedge or profit interest or other transaction has been entered into by or on behalf of such person, or any affiliates or associates of such person, with respect to stock of the Company; (v) whether and the extent to which any other transaction, agreement, arrangement or understanding (including any short position or any borrowing or lending of shares of stock of the Company) has been made by or on behalf of such person, or any affiliates or associates of such person, the effect or

intent of any of the foregoing being to mitigate loss to, or to manage risk or benefit of stock price changes for, such person, or any affiliates or associates of such person, or to increase or decrease the voting power or pecuniary or economic interest of such person, or any affiliates or associates of such person, with respect to stock of the Company, (vi) such person's written representation and agreement that such person (A) is not and will not become a party to any agreement, arrangement or understanding with, and has not given any commitment or assurance to, any person or entity as to how such person, if elected as a director of the Company, will act or vote on any issue or question and (B) in such person's individual capacity, would be in compliance, if elected as a director of the Company, and will comply with, all applicable publicly disclosed confidentiality, corporate governance, conflict of interest, Regulation FD, code of conduct and ethics, and stock ownership and trading policies and guidelines of the Company; (vii) a description of any agreement, arrangement or understanding with any person or entity other than the Company with respect to any direct or indirect compensation, reimbursement or indemnification in connection with service or action as a director of the Company and (viii) all other information relating to such person that is required to be disclosed in solicitations of proxies for election of directors, or is otherwise required, in each case pursuant to Section 14(a) of the Exchange Act and the rules and regulations promulgated thereunder;

(b) as to any other business that the stockholder proposes to bring before the meeting, a brief description of the business desired to be brought before the meeting, the text of the proposal or business (including the text of any resolutions proposed for consideration and, in the event that such business includes a proposal to amend these By-Laws, the language of the proposed amendment), the reasons for conducting such business at the meeting and any material interest in such business of such stockholder and the beneficial owner, if any, on whose behalf the proposal is made;

(c) as to the stockholder giving the notice and the beneficial owner, if any, on whose behalf the nomination or proposal is made (i) the name and record address of such stockholder, as they appear on the Company's books and records, and of such beneficial owner, (ii) the class or series and number of shares of capital stock of the Company which are owned directly or indirectly, beneficially and of record by such stockholder and such beneficial owner, (iii) a representation that the stockholder is a holder of record of the stock of the Company at the time of the giving of the notice, will be entitled to vote at such meeting and will appear in person or by proxy at the meeting to propose such business or nomination, (iv) a representation whether the stockholder or the beneficial owner, if any, or any of their respective affiliates, associates or others acting in concert therewith (collectively, "proponent persons") will be or is part of a group which will (A) deliver a proxy statement and/or form of proxy to holders of at least the percentage of the voting power of the Company's outstanding capital stock required to approve or adopt the proposal or elect the nominee and/or (B) otherwise solicit proxies or votes from stockholders in support of such proposal or nomination, (v) if such stockholder or any other proponent person intends to engage in a solicitation with respect to a nomination pursuant to this Section 18, (A) a statement disclosing the name of each participant in such solicitation (as defined in Item 4 of Schedule 14A under the Exchange Act) and (B) a representation that such stockholder or other proponent person, if any, intends to deliver a proxy statement and form of proxy to holders of at least the percentage of the Company's outstanding capital stock required under Rule 14a-19 under the Exchange Act; (vi) a certification regarding whether such stockholder and beneficial owner, if any, have complied with all applicable federal, state and other legal requirements in connection with the stockholder's and/

or beneficial owner's acquisition of shares of capital stock or other securities of the Company and/or the stockholder's and/or beneficial owner's acts or omissions as a stockholder of the Company and (vii) any other information relating to such stockholder and beneficial owner, if any, required to be disclosed in a proxy statement or other filings required to be made in connection with solicitations of proxies for, as applicable, the proposal and/or for the election of directors in an election contest pursuant to and in accordance with Section 14(a) of the Exchange Act and the rules and regulations promulgated thereunder;

(d) a description of any agreement, arrangement or understanding with respect to the nomination or proposal and/or the voting of shares of any class or series of stock of the Company between or among the stockholder giving the notice and any other proponent person; and

(e) a description of any agreement, arrangement or understanding (including without limitation any contract to purchase or sell, acquisition or grant of any option, right or warrant to purchase or sell, swap or other instrument) the intent or effect of which may be (i) to transfer to or from any proponent person, in whole or in part, any of the economic consequences of ownership of any security of the Company, (ii) to increase or decrease the voting power of any proponent person with respect to shares of any class or series of stock of the Company and/or (iii) to provide any proponent person, directly or indirectly, with the opportunity to profit or share in any profit derived from, or to otherwise benefit economically from, any increase or decrease in the value of any security of the Company.

(4) A stockholder providing notice of a proposed nomination for election to the Board or other business proposed to be brought before a meeting (whether given pursuant to this paragraph (A) or paragraph (B) of this Section 18) shall update and supplement such notice from time to time to the extent necessary so that the information provided or required to be provided in such notice shall be true and correct as of the record date for determining the stockholders entitled to notice of the meeting and as of the date that is fifteen (15) days prior to the meeting or any adjournment or postponement thereof, provided that if the record date for determining the stockholders entitled to vote at the meeting is less than fifteen (15) days prior to the meeting or any adjournment or postponement thereof, the information shall be supplemented and updated as of such later date. Any such update and supplement shall be delivered in writing to the Secretary at the principal executive offices of the Company not later than five (5) days after the record date for determining the stockholders entitled to notice of the meeting (in the case of any update or supplement required to be made as of the record date for determining the stockholders entitled to notice of the meeting), not later than ten (10) days prior to the date for the meeting or any adjournment or postponement thereof (in the case of any update or supplement required to be made as of fifteen (15) days prior to the meeting or any adjournment or postponement thereof) and not later than five (5) days after the record date for determining the stockholders entitled to vote at the meeting, but no later than the date prior to the meeting or any adjournment or postponement thereof (in the case of any update and supplement required to be made as of a date less than fifteen (15) days prior the date of the meeting or any adjournment or postponement thereof). In addition, if any stockholder provides notice of a proposed nomination for election to the Board pursuant to Rule 14a-19 under the Exchange Act, such stockholder shall deliver to the Company, no later than seven (7) business days prior to the applicable meeting, reasonable evidence that it has met the requirements of Rule 14a-19 under the Exchange Act. In addition to the other requirements of this Section 18, each person whom a stockholder proposes to nominate for election to the Board must deliver in writing (in

accordance with the time periods prescribed for delivery of notice under Section 18(A)(2) herein) to the Secretary at the principal executive offices of the Company a completed written questionnaire with respect to the background, qualifications, stock ownership and independence of such proposed nominee (which questionnaire shall be provided by the Secretary upon written request of any stockholder of record identified by name within five (5) business days of such written request). The Company may require any proposed nominee to furnish such other information as it may reasonably require to determine the eligibility of such proposed nominee to serve as a director of the Company and to determine the independence of such director under the Exchange Act and rules and regulations thereunder and applicable stock exchange rules. No person shall be eligible for election as a director of the Company unless nominated in accordance with the procedures set forth in subparagraphs (1), (2), (3) and (4) of this paragraph (A) of this Section 18 or with Section 19. If the Chair of the meeting determines that a nomination was not made in accordance with the foregoing procedures, such nomination shall be disregarded, and the Chair shall so declare to the meeting.

(5) Notwithstanding anything in the second sentence of paragraph (A)(2) of this Section 18 to the contrary, in the event that the number of directors to be elected to the Board is increased, effective after the time period for which nominations would otherwise be due under paragraph (A)(2) of this Section 18, and there is no public announcement naming all of the nominees for director or specifying the size of the increased Board made by the Company at least one hundred (100) days prior to the first anniversary of the preceding year's annual meeting, a stockholder's notice required by this Section 18 shall also be considered timely, but only with respect to nominees for any new positions created by such increase, if it shall be delivered to the Secretary at the principal executive offices of the Company not later than the close of business on the tenth day following the day on which a public announcement of such increase is first made by the Company; provided that, if no such announcement is made at least ten (10) days before the meeting, then no such notice shall be required.

(B) Special Meetings of Stockholders. Only such business shall be conducted at a special meeting of stockholders as shall have been brought before the meeting pursuant to the Company's notice of meeting pursuant to Section 3 of these By-Laws. Nominations of persons for election to the Board may be made at a special meeting of stockholders at which directors are to be elected pursuant to the Company's notice of meeting only (a) by or at the direction of the Board or a committee thereof or (b) provided that the Board has determined that directors shall be elected at such meeting, by any stockholder of the Company who is entitled to vote on such election at the meeting, who complies with the notice procedures set forth in this Section 18 and who is a stockholder of record at the time such notice is delivered to the Secretary of the Company. In the event the Company calls a special meeting of stockholders for the purpose of electing one or more directors to the Board, any such stockholder entitled to vote in such election of directors may nominate a person or persons (as the case may be) for election to such position(s) as specified in the Company's notice of meeting if the stockholder's notice as required by paragraph (A)(2) of this Section 18 shall be delivered to the Secretary at the principal executive offices of the Company not earlier than the 120th day prior to such special meeting and not later than the close of business on the later of the 90th day prior to such special meeting or the tenth day following the day on which public announcement is first made of the date of the special meeting and of the nominees proposed by the Board to be elected at such meeting.

(C) General. (1) Notwithstanding the foregoing provisions of this Section 18, unless otherwise required by law, if any stockholder (i) provides notice of a proposed nomination for election to the Board pursuant to Rule 14a-19 under the Exchange Act and (ii) subsequently fails to comply with any requirements of Rule 14a-19 under the Exchange Act or any other rules or regulations thereunder, as determined by the Chair of the meeting, then the Company shall disregard any proxies or votes solicited for such nominees. In addition, any stockholder that provides notice of a proposed nomination for election to the Board pursuant to Rule 14a-19 under the Exchange Act shall notify the Secretary within two (2) business days of any change in such stockholder's intent to deliver a proxy statement and form of proxy to the amount of holders of shares of the Company's outstanding capital stock required under Rule 14a-19 under the Exchange Act.

(2) Only persons who are nominated in accordance with the procedures set forth in this Section 18 and Section 19, as applicable, shall be eligible to serve as directors and only such business shall be conducted at a meeting of stockholders as shall have been brought before the meeting in accordance with the procedures set forth in this Section 18. Except as otherwise provided by law, the Certificate of Incorporation or these By-Laws, the Chair of the meeting shall have the power and duty to determine whether a nomination or any business proposed to be brought before the meeting was made in accordance with the procedures set forth in this Section 18 or Section 19, as applicable, and, if any proposed nomination or business is not in compliance with this Section 18 or Section 19, as applicable, to declare that such defective nomination shall be disregarded or that such proposed business shall not be transacted.

Notwithstanding the foregoing provisions of this Section 18, if the stockholder (or a qualified representative of the stockholder) does not appear at the annual or special meeting of stockholders of the Company to present a nomination or business, such nomination shall be disregarded and such proposed business shall not be transacted, notwithstanding that proxies in respect of such vote may have been received by the Company. For purposes of this Section 18, to be considered a qualified representative of the stockholder, a person must be a duly authorized officer, manager or partner of such stockholder or must be authorized by a writing executed by such stockholder or an electronic transmission delivered by such stockholder to act for such stockholder as proxy at the meeting of stockholders and such person must produce such writing or electronic transmission, or a reliable reproduction of the writing or electronic transmission, at the meeting of stockholders.

(3) For purposes of this Section 18 and Section 19, "public announcement" shall mean disclosure in a press release reported by the Dow Jones News Service, Associated Press or comparable national news service, in a document publicly filed or furnished by the Company with the Securities and Exchange Commission pursuant to Section 13, 14 or 15(d) of the Exchange Act or otherwise disseminated in a manner constituting "public disclosure" under Regulation FD promulgated by the Securities and Exchange Commission.

(4) No adjournment or postponement or notice of adjournment or postponement of any meeting shall be deemed to constitute a new notice of such meeting for purposes of this Section 18 or Section 19, and in order for any notification required to be delivered by a stockholder pursuant

to this Section 18 or Section 19 to be timely, such notification must be delivered within the periods set forth above or in paragraph (B)(2) of Section 19, as applicable, with respect to the originally scheduled meeting.

(5) Notwithstanding the foregoing provisions of this Section 18, a stockholder shall also comply with all applicable requirements of the Exchange Act and the rules and regulations thereunder with respect to the matters set forth in this Section 18 and in Section 19; provided however, that, to the fullest extent permitted by law, any references in these By-Laws to the Exchange Act or the rules and regulations promulgated thereunder are not intended to and shall not limit any requirements applicable to nominations or proposals as to any other business to be considered pursuant to this Section 18 (including paragraphs (A)(1)(c) and (B) hereof) or Section 19, and compliance with paragraphs (A)(1)(c) and (B) of this Section 18 and Section 19 (in the case of any Stockholder Nominee nominated pursuant thereto) shall be the exclusive means for a stockholder to make nominations or submit other business.

(6) Any stockholder directly or indirectly soliciting proxies from other stockholders must use a proxy card color other than white, which shall be reserved for the exclusive use by the Board of Directors. (As amended December 6, 2022.)

Section 19. (A) In addition to any persons nominated for election to the Board of Directors by or at the direction of the Board of Directors or any committee thereof, subject to the provisions of this Section 19, the Company shall (1) include in its proxy materials for any annual meeting of stockholders (a) the name of any person nominated for election (the "Stockholder Nominee") by a stockholder of record of the Company at the time of the Notice of Proxy Access Nomination (as defined below) who is entitled to vote at the annual meeting and who satisfies the notice, ownership and other requirements of this Section 19 (a "Nominator") or by a group of no more than twenty (20) such stockholders (a "Nominator Group") that, collectively as a Nominator Group, satisfies the notice, ownership and other requirements of this Section 19 applicable to a Nominator Group; provided, that, in the case of a Nominator Group, each member thereof (each a "Group Member") shall have satisfied the conditions and complied with the procedures set forth in this Section 19 applicable to Group Members, and (b) the Nomination Statement (as defined below) furnished by such Nominator or Nominator Group; and (2) include such Stockholder Nominee's name on any ballot distributed at such annual meeting and on the Company's proxy card (or any other format through which the Company permits proxies to be submitted) distributed in connection with such annual meeting. Nothing in this Section 19 shall limit the Company's ability to solicit against, and include in its proxy materials its own statements relating to, any Stockholder Nominee, or to include such person as a nominee of the Board of Directors.

(B) (1) At each annual meeting of stockholders, the Nominator or Nominator Group may nominate one or more Stockholder Nominees for election at such meeting pursuant to this Section 19; provided, that, the maximum number of Stockholder Nominees appearing in the Company's proxy materials with respect to an annual meeting of stockholders (including any Stockholder Nominee whose name was submitted by a Nominator or Nominator Group for inclusion in the Company's proxy materials pursuant to this Section 19 but who is nominated by the Board as a Board of Director nominee, together with any nominees who were previously elected to the Board as Stockholder Nominees at any of the preceding two annual meetings and who are re-nominated for election at such annual meeting by the Board and any Stockholder Nominee who was qualified

for inclusion in the Company's proxy materials but whose nomination is subsequently withdrawn), shall be the greater of (x) two or (y) the largest whole number that does not exceed 20 % of the number of directors in office as of the Final Proxy Access Deadline (as defined below (the "Maximum Number"). If one or more vacancies for any reason occurs on the Board of Directors at any time after the Final Proxy Access Deadline and before the date of the applicable annual meeting of stockholders and the Board of Directors resolves to reduce the size of the Board of Directors in connection therewith, the Maximum Number shall be calculated based on the number of directors in office as so reduced. Any Nominator or Nominator Group submitting more than one Stockholder Nominee for inclusion in the Company's proxy materials pursuant to this Section 19(B) shall rank in its Notice of Proxy Access Nomination such Stockholder Nominees based on the order that the Nominator or Nominator Group desires such Stockholder Nominees to be selected for inclusion in the Company's proxy materials in the event that the total number of Stockholder Nominees submitted by Nominators or Nominator Groups pursuant to this Section 19(B) exceeds the Maximum Number. In the event that the number of Stockholder Nominees submitted by Nominators or Nominator Groups pursuant to this Section 19 exceeds the Maximum Number, the highest ranking Stockholder Nominee who meets the requirements of this Section 19 from each Nominator and Nominator Group will be selected for inclusion in the Company's proxy materials until the Maximum Number is reached, with priority based on the amount (going in order of largest to smallest) of shares of common stock of the Company each Nominator and Nominator Group disclosed as owned (as defined below) in its respective Notice of Proxy Access Nomination submitted to the Company. If the Maximum Number is not reached after the highest ranking Stockholder Nominee who meets the requirements of this Section 19 from each Nominator and Nominator Group has been selected, this process will continue as many times as necessary, following the same order each time, until the maximum number is reached.

(2) To nominate any such Stockholder Nominee, the Nominator or Nominator Group shall:

(a) not earlier than the one hundred fiftieth (150th) calendar day and no later than the close of business on the one hundred twentieth (120th) calendar day prior to the anniversary of the date the Company commenced mailing of its proxy materials in connection with the most recent annual meeting, provided that if such meeting is convened more than thirty (30) days prior to or delayed by more than seventy (70) days after the anniversary of the preceding year's annual meeting, or if no annual meeting was held in the preceding year, the Notice of Proxy Access Nomination must be so delivered not later than the close of business on the later of (x) the one hundred twentieth (120th) calendar day prior to such annual meeting or (y) the tenth (10th) calendar day following the day on which a public announcement of the annual meeting date is first made (the last day on which a Notice of Proxy Access Nomination may be delivered, the "Final Proxy Access Deadline"), submit to the Secretary of the Company:

(i) a written notice of the nomination of such Stockholder Nominee expressly electing to have such Stockholder Nominee included in the Company's proxy materials pursuant to this Section 19 that includes (x) with respect to the Nominator (including any fund comprising a Qualifying Fund (as hereinafter defined)) (and any beneficial owner on whose behalf the nomination is made) or, in the case of a Nominator Group, with respect to each Group Member (including each fund comprising a Qualifying Fund) (and any beneficial owner on whose behalf the nomination is made) all of the information required by Section 18(A)(3)(c)-(e) of these By-Laws and

(y) with respect to each such Stockholder Nominee, all of the information required by Section 18(A)(3)(a) (such written notice, the "Notice of Proxy Access Nomination");

(ii) the written consent of each Stockholder Nominee to being named in the Company's proxy materials as a nominee and to serving as a director if elected;

(iii) if the Nominator or Nominator Group so elects, a statement for inclusion in the Company's proxy statement in support of each Stockholder Nominee's election to the Board of Directors, which statement shall not exceed five hundred (500) words with respect to each Stockholder Nominee (the "Nomination Statement");

(iv) in the case of a nomination by a Nominator Group, the designation by all Group Members of one specified Group Member that is authorized to act on behalf of all Group Members with respect to the nomination and matters related thereto, including withdrawal of the nomination;

(v) a representation that all of the facts, statements and other information included in all communications by the Nominator or Nominator Group (including any Group Member and any fund comprising a Qualifying Fund) with the Company and its stockholders, including without limitation the Notice of Proxy Access Nomination and the Nomination Statement, are or will be true and correct in all material respects (and shall not omit to state a material fact necessary in order to make the statements made in light of the circumstances under which they were made, not misleading);

(vi) one or more written statements from the stockholder of record of the Required Shares (as defined below), and from each intermediary through which such shares are or have been held during the requisite three-year holding period, verifying that, as of a date within seven (7) calendar days prior to the date the Notice of Proxy Access Nomination is received by the Secretary of the Company, the Nominator or the Nominator Group, as the case may be, owns, and has owned continuously for the preceding three (3) years, the Required Shares, and the Nominator's (or, in the case of a Nominator Group, each Group Member's) agreement to provide (A) within five (5) business days after the record date for the applicable annual meeting, written statements from the record holder and intermediaries verifying the Nominator or the Nominator Group's, as the case may be, continuous ownership of the Required Shares through the record date, provided that if and to the extent that a stockholder of record is acting on behalf of one or more beneficial owners, such written statements shall also be submitted by any such beneficial owner or owners, and (B) immediate notice if the Nominator or the Nominator Group, as the case may be, ceases to own any of the Required Shares prior to the date of the applicable annual meeting;

(vii) a copy of the Schedule 14N that has been filed with the Securities and Exchange Commission (the "SEC") as required by Rule 14a-18 under the Exchange Act;

(viii) a representation by the Nominator (and any beneficial owner on whose behalf the nomination is made), or, in the case of a Nominator Group, each Group Member (and any beneficial owner on whose behalf the nomination is made): (1) that the Required Shares were acquired in the ordinary course of business and not with intent to cause or to contribute to the causation of a change of control of the Company, and each such person does not presently have

such intent, (2) that each such person or entity will maintain ownership (as defined in this Section 19) of the Required Shares through the date of the applicable annual meeting of stockholders, (3) that each such person or entity has not nominated, and will not nominate, for election to the Board of Directors at the applicable annual meeting any person other than its Stockholder Nominee(s) pursuant to this Section 19, (4) that each such person or entity has not distributed, and will not distribute, to any stockholder any form of proxy for the applicable annual meeting other than the form distributed by the Company, and (5) that each such person or entity has not engaged, and will not engage in, and has not been and will not be, a participant (as defined in Schedule 14A of the Exchange Act) in, a "solicitation" within the meaning of Rule 14a-1(l) under the Exchange Act in support of the election of any individual as a director at the applicable annual meeting other than its Stockholder Nominee(s) or a nominee of the Board of Directors;

(ix) an executed agreement, in a form deemed satisfactory by the Board of Directors acting in good faith, pursuant to which the Nominator (and any beneficial owner on whose behalf the nomination is made or any fund comprising a Qualifying Fund), (or, in the case of a Nominator Group, each Group Member (and any beneficial owner on whose behalf the nomination is made or any fund comprising a Qualifying Fund)) agrees to (1) comply with all applicable laws and regulations arising out of or relating to the nomination of each Stockholder Nominee pursuant to this Section 19, (2) assume all liability stemming from any legal or regulatory violation arising out of the communications and information provided by such person(s) to the Company and its stockholders in connection with the Notice of Proxy Access Nomination and the Nomination Statement, (3) indemnify and hold harmless the Company and each of its directors, officers, employees, agents and affiliates individually against any liability, loss or damages in connection with any threatened or pending action, suit or proceeding, whether legal, administrative or investigative, against the Company or any of its directors, officers, employees, agents and affiliates arising out of or relating to any nomination submitted by such person(s) pursuant to this Section 19, (4) file with the SEC any solicitation or other communication with the Company's stockholders relating to the meeting at which the Stockholder Nominee will be nominated, regardless of whether any such filing is required under Regulation 14A of the Exchange Act or whether any exemption from filing is available for such solicitation or other communication under Regulation 14A of the Exchange Act, and (5) furnish to the Company all updated information required by this Section 19, including, without limitation, the penultimate sentence of Section 19(B)(3); and

(b) have owned or, in the case of a Nominator Group, collectively as a Nominator Group owned (as defined below) common stock of the Company representing three percent (3%) or more of the voting power entitled to vote generally in the election of directors (the "Required Shares") continuously for at least three years as of the date the Notice of Proxy Access Nomination is submitted to the Company and who continue to own such shares of common stock at all times between the date the Notice of Proxy Access Nomination is submitted to the Company and the date of the applicable annual meeting; provided that if and to the extent a stockholder of record is acting on behalf of one or more beneficial owners (i) only the common stock of the Company owned by such beneficial owner or owners, and not any other common stock of the Company owned by any such stockholder of record, shall be counted for purposes of satisfying the foregoing ownership requirement and (ii) the aggregate number of stockholders of record and all such beneficial owners whose stock ownership is counted for the purposes of satisfying the foregoing ownership requirement shall not exceed twenty (20). Two or more funds that are (i) under common management and investment control or (ii) under common management and funded primarily by a

single employer (such funds together under each of (i) or (ii) comprising a "Qualifying Fund") shall be treated as one stockholder for the purpose of determining the aggregate number of stockholders in this Section 19(B)(2)(b), and treated as one person for the purpose of determining ownership in Section 19, provided that each fund comprising a Qualifying Fund otherwise meets the requirements set forth in this Section 19. No stockholder (record or beneficial) may be, or shall have been within the three (3) months prior to the Final Proxy Access Deadline, a member of more than one Nominator Group.

For purposes of calculating the Required Shares, "ownership" shall be deemed to consist of and include only the outstanding shares of common stock as to which a person possesses both (i) the full voting and investment rights pertaining to such shares and (ii) the full economic interest in (including the opportunity for profit and risk of loss on) such shares; provided that the ownership of shares calculated in accordance with clauses (i) and (ii) shall not include any shares (A) that a person or any of its affiliates (as such term is defined in the Exchange Act) has sold in any transaction that has not been settled or closed, (B) that a person or any of its affiliates has borrowed or purchased pursuant to an agreement to resell or (C) subject to any option, warrant, forward contract, swap, contract of sale, other derivative or similar agreement entered into by a person or any of its affiliates, whether any such instrument or agreement is to be settled with shares or with cash based on the notional amount or value of shares of the Company's common stock, in any such case which instrument or agreement has, or is intended to have, the purpose or effect of (1) reducing in any manner, to any extent or at any time in the future, the person's or affiliates' full right to vote or direct the voting of any such shares, and/or (2) hedging, offsetting or altering to any degree gain or loss arising from the full economic ownership of such person's or affiliates' shares of common stock. A person's ownership of shares shall be deemed to continue during any period in which (i) the person has loaned such shares, provided that the person has the power to recall such loaned shares on five (5) business days' notice; or (ii) the person has delegated any voting power by means of a proxy, power of attorney or other instrument or arrangement that is revocable at any time by the person. "Ownership" shall include shares held in the name of a nominee or other intermediary so long as the person or entity claiming ownership of such shares retains the right to instruct how the shares are voted with respect to the election of directors and possesses the full economic interest in the shares. The determination of the extent of "ownership" of shares for purposes of this Section 19 shall be made in good faith by the Board of Directors, which determination shall be conclusive and binding on the Company and the stockholders. The terms "owned," "owning" and other variations of the word "own" shall have correlative meanings.

(3) For the avoidance of doubt, with respect to any nomination submitted by a Nominator Group pursuant to this Section 19, the information required by Section 18(A)(3) of these By-Laws shall be provided by each Group Member (including each fund comprising a Qualifying Fund) (and any beneficial owner on whose behalf the nomination is made) and each such Group Member (including each fund comprising a Qualifying Fund) (and any beneficial owner on whose behalf the nomination is made) shall execute and deliver to the Secretary of the Company the representations and agreements required under Section 19(B)(2)(a) hereof at the time the Notice of Proxy Access Nomination is submitted to the Company (or, in the case of any person or entity who becomes a Group Member after such date, within 48 hours of becoming a Group Member).

In the event that the Nominator, Nominator Group or any Group Member shall have breached any of their agreements with the Company or any information included in the

Nomination Statement, or any other communications by the Nominator, Nominator Group or any Group Member (including any fund comprising a Qualifying Fund) (and any beneficial owner on whose behalf the nomination is made) with the Company or its stockholders, ceases to be true and correct in all material respects (or omits a material fact necessary to make the statements made, in light of the circumstances under which they were made and as of such later date, not misleading), each Nominator, Nominator Group or Group Member (including each fund comprising a Qualifying Fund) (and any beneficial owner on whose behalf the nomination is made), as the case may be, shall promptly (and in any event within twenty-four (24) hours of discovering such breach or that such information has ceased to be true and correct in all material respects (or omits a material fact necessary to make the statements made, in light of the circumstances under which they were made and as of such later date, not misleading)) notify the Company of any such breach or any defect in such previously provided information and of the information that is required to correct any such defect, if applicable. All such information required to be included in the Notice of Proxy Access Nomination ("Notice of Proxy Access Information") shall be true and correct (x) as of the record date for determining the stockholders entitled to notice of the meeting and (y) as of the date that is fifteen (15) days prior to the meeting or any adjournment or postponement thereof, provided that if the record date for determining the stockholders entitled to vote at the meeting is less than fifteen (15) days prior to the meeting or any adjournment or postponement thereof, the information shall be supplemented and updated to make Notice of Proxy Access Information true and correct as of such later date. Any update or supplement required to make Notice of Proxy Access Information true and correct shall be delivered in writing to the Secretary of the Company at the principal executive offices of the Company not later than five (5) days after the record date for determining the stockholders entitled to notice of the meeting (in the case of Notice of Proxy Information required to be true and correct as of the record date for determining the stockholders entitled to notice of the meeting), not later than ten (10) days prior to the date for the meeting or any adjournment or postponement thereof (in the case of Notice of Proxy Information required to be true and correct as of fifteen (15) days prior to the meeting or adjournment or postponement thereof) and not later than five (5) days after the record date for determining the stockholders entitled to vote at the meeting, but no later than the date prior to the meeting or any adjournment or postponement thereof (in the case of Notice of Proxy Information required to be true and correct as of a date less than fifteen (15) days prior the date of the meeting or any adjournment or postponement thereof). Notwithstanding anything to the contrary set forth herein, if any Nominator, Nominator Group or Group Member (including each fund comprising a Qualifying Fund) (and any beneficial owner on whose behalf the nomination is made) has failed to comply with the requirements of this Section 19(B), the Board of Directors or the Chair of the meeting shall declare the nomination by such Nominator or Nominator Group to be invalid, and such nomination shall be disregarded.

(4) (a) Within the time period specified in these By-Laws for providing the applicable nomination, each Stockholder Nominee must deliver to the Secretary of the Company a written representation and agreement that such person (i) understands his or her duties as a director under the New York Business Corporation Law (the "NYBCL") and agrees to act in accordance with those duties while serving as a director, (ii) is not or will not become a party to any agreement, arrangement or understanding with, and has not given any commitment or assurance to, any person or entity as to how such nominee, if elected as a director of the Company, will act or vote as a director on any issue or question to be decided by the board of directors or that otherwise relates to the Company or the Stockholder Nominee's service on the Board of Directors, (iii) has disclosed

to the Company whether he or she is a party to any compensatory, payment or other financial agreement, arrangement or understanding with any person or entity other than the Company, including any agreement to indemnify such person for obligations arising as a result of his or her service as a director of the Company, in connection with such nominee's nomination, service or action as a director of the Company, (iv) if elected as a director of the Company, will comply with all applicable laws and stock exchange listing standards and the Company's policies, guidelines and principles applicable to directors, including, without limitation, all applicable corporate governance, conflict of interest, confidentiality and stock ownership and trading policies and guidelines of the Company, and (v) will provide facts, statements and other information in all communications with the Company and its stockholders that are or will be true and correct in all material respects and do not and will not omit to state a material fact necessary in order to make the statements made, in light of the circumstances under which they were made, not misleading.

(b) At the request of the Company, each Stockholder Nominee for election as a director of the Company must promptly submit (but in no event later than five (5) business days after receipt of the request) to the Secretary of the Company all completed and signed questionnaires required of directors and officers. The Company may request such additional information as necessary to permit the Board of Directors to determine if each nominee is independent under the listing standards of each principal U.S. exchange upon which the common stock of the Company is listed, any applicable rules of the SEC and any publicly disclosed standards used by the board of directors in determining and disclosing the independence of the Company's directors and to determine whether the nominee otherwise meets all other publicly disclosed standards applicable to directors.

(c) In the event that any information or communications provided by a Stockholder Nominee, to the Company or its stockholders ceases to be true and correct in any respect or omits a fact necessary to make the statements made, in light of the circumstances under which they were made, not misleading, such nominee shall promptly notify the Secretary of the Company of any such inaccuracy or omission in such previously provided information and of the information that is required to make such information or communication true and correct.

(C) Any Stockholder Nominee who is included in the Company's proxy materials for a particular annual meeting of stockholders but withdraws from or becomes ineligible or unavailable for election at the annual meeting will be ineligible to be a Stockholder Nominee pursuant to this Section 19 for the next two annual meetings.

(D) The Company shall not be required to include, pursuant to this Section 19, a Stockholder Nominee in its proxy materials for any meeting of stockholders, or, if the proxy statement already has been filed, to allow the nomination of a Stockholder Nominee, notwithstanding that proxies in respect of such vote may have been received by the Company: (i) for any meeting for which the Secretary of the Company receives notice that the Nominator, the Nominator Group or any Group Member, as the case may be, or any other stockholder of record, intends to nominate one or more persons for election to the Board of Directors pursuant to Section 18, (ii) who is not independent under the listing standards of each principal U.S. exchange upon which the common stock of the Company is listed, any applicable rules of the SEC, or any publicly disclosed standards used by the Board of Directors in determining and disclosing independence of the Company's directors, in each case as determined by the Board of Directors in good faith; (iii) who does not meet the audit committee independence requirements under the rules of any stock

exchange on which the Company's securities are traded, is not a "non-employee director" for the purposes of Rule 16b-3 under the Exchange Act (or any successor rule), is not an "outside director" for the purposes of Section 162(m) of the Internal Revenue Code (or any successor provision); (iv) whose election as a member of the Board of Directors would cause the Company to be in violation of these By-Laws, the Certificate of Incorporation, the rules and listing standards of the principal U.S. securities exchanges upon which the common stock of the Company is listed, or any applicable law, rule or regulation or of any publicly disclosed standards of the Company applicable to directors, in each case as determined by the Board of Directors in good faith; (v) who is or has been, within the past three (3) years, an officer or director of a competitor, as defined in Section 19 of the Clayton Antitrust Act of 1914; (vi) who is a named subject of a pending criminal proceeding (excluding traffic violations and other minor offenses) or has been convicted in such a criminal proceeding within the past ten (10) years; (vii) who is subject to any order of the type specified in Rule 506(d) of Regulation D promulgated under the Securities Act of 1933, as amended; (viii) if such stockholder shall have provided information to the Company in connection with such nomination that was untrue in any material respect or omitted to state a material fact necessary in order to make any statement made, in light of the circumstances under which it was made, not misleading, as determined by the Board of Directors or any committee thereof in good faith; (ix) to the extent permitted under applicable law, the Nominator or Nominator Group, or, in the case of a Nominator Group, any Group Member, or the Stockholder Nominee does not appear at the applicable annual meeting to present the Stockholder Nominee for election; (x) the Nominator or, in the case of a Nominator Group, any Group Member, or applicable Stockholder Nominee otherwise breaches or fails to comply with its representations or obligations pursuant to these By-Laws, including, without limitation, this Section 19. For the purpose of this paragraph, clauses (ii) through (x) will result in the exclusion from the proxy materials pursuant to this Section 19 of the specific Stockholder Nominee to whom the ineligibility applies, or, if the proxy statement already has been filed, the ineligibility of the Stockholder Nominee and the inability of the Nominator or Nominator Group that nominated such stockholder to substitute another Stockholder Nominee therefor; however, clause (i) will result in the exclusion from the proxy materials pursuant to this Section 19 of all Stockholder Nominees from the applicable annual meeting, or, if the proxy statement already has been filed, the ineligibility of all Stockholder Nominees.

(E) Notwithstanding anything to the contrary contained in this Section 19, the Company may omit from its proxy materials any information, including all or any portion of the Nomination Statement, if the Board of Directors in good faith determines that the disclosure of such information would violate any applicable law or regulation or that such information is not true and correct in all material respects or omits to state a material fact necessary in order to make the statements made, in light of the circumstances under which they were made, not misleading. (As amended December 7, 2021.)

FIRST AMENDMENT
to the
AMERICAN ELECTRIC POWER EXECUTIVE SEVERANCE PLAN
(As Amended and Restated Effective July 15, 2024)

This First Amendment to the American Electric Power Executive Severance Plan (the "Plan") is signed pursuant to a determination of the Human Resources Committee of American Electric Power Company, Inc. (the "Committee"), adopted at its meeting held the 17th day of February, 2025. The Plan was initially adopted on January 15, 2014 and last amended and restated July 15, 2024.

Recitals

A. The Committee has authorized the issuance of Restricted Stock Unit ("RSU) Award Agreements that provide an opportunity for accelerated vesting for those participants who satisfy certain criteria to be considered retirement-eligible, entitling those participants to a prorated payout of shares notwithstanding their termination of employment prior to a specified Vesting Date, and

B. Compliance with Section 409A of the federal Internal Revenue Code may require that the prorated payout of those shares occur no earlier than 6 months following the participant's termination of employment; and

C. This amendment to the Plan is intended to better assure compliance with that 6-month deferral feature of the implicated RSU Award Agreements.

Amendment

1. Section 5.1(b) of the Plan is hereby amended in its entirety to read as follows:

(b) Payment of Restricted Stock Unit Award Severance Benefits. The Restricted Stock Unit Award benefit described in Section 4.1(b) shall be satisfied by converting into a single share of AEP Common Stock each RSU (including each Granted RSU and each vested Dividend Equivalent RSU) that thereupon becomes vested. The shares of AEP Common Stock resulting from the conversion of the vested RSUs shall be delivered to the Participant or to an account set up for the Participant's benefit with a broker/dealer designated by the Company (the "Broker/Dealer Account") as soon as practicable on or after the last day of the sixth month after the Participant's Termination Date; provided, however, if the Restricted Stock Unit Award Agreement does not define a Retirement Payout Date that is later than a defined Retirement Vesting Date, such RSUs shall be delivered to the Participant as soon as practicable on or after the earlier to occur of (a) the last day of the sixth month after the Participant's Termination Date or (b) the first day of the third month after the calendar year in which falls the Participant's Termination Date (but no later than the fifteenth day of that third month, or the immediately preceding business day of such broker-dealer, if that

fifteenth day is not such a business day). AEP Common Stock and all Participants remain subject to all applicable legal and regulatory restrictions such as insider trading restrictions and black-out periods.

2. In all other respects, the terms of the Plan are ratified and confirmed.

Signed this 18th, day of February, 2025.

American Electric Power Company, Inc.

By __
William Fehrman, Chief Executive Officer and President

American Electric Power Company, Inc.
1 Riverside Plaza
Columbus, OH 43215-2373

December 20, 2025

Andrew Teno
Via Email

Dear Andrew:

This letter agreement (this "Agreement") outlines the terms of your appointment as a non-voting Board Observer to the Board of Directors (the "Board") of American Electric Power Company, Inc., a New York Corporation (the "Company"). This Agreement is effective as of December 22, 2025. This Agreement shall be acknowledged and agreed to by the persons and entities listed on Schedule A (collectively, the "Icahn Group," and each individually a "member" of the Icahn Group).

In your capacity as Board Observer, you will attend Board meetings in accordance with this Agreement. As Board Observer, you will receive, contemporaneous with their distribution to the Board, copies of all documents distributed to the Board, including notice of all meetings of the Board, all written consents of the Board, all materials prepared for consideration at any meeting of the Board, and all minutes related to each meeting of the Board. You will be permitted to attend and reasonably participate, but not vote, at all meetings of the Board (whether such meetings are held in person, telephonically or otherwise) but you will not have other rights of a member of the Board. You will confirm your attendance at any such meeting as promptly as practicable following receipt of the notice of such meeting (and, in any event, at least three (3) business days prior to the meeting). Notwithstanding the foregoing, the Company reserves the right to exclude you from access to any document, material or meeting or portion thereof if, and only to the extent that, (i) the Company reasonably determines that (x) such exclusion is necessary to preserve any attorney-client privilege or in order to comply with (or to not reasonably be expected to violate) any law, rule or regulation (including any rule or regulation of the Nasdaq Stock Market LLC) applicable to the Company or its subsidiaries or (y) such document, material or meeting or portion thereof does not concern the corporate strategy and financial and operational performance of the Company or mergers and other acquisitions of material assets, dispositions of material assets or similar material business combination transactions, (ii) the Board reasonably determines, from a governance perspective, that it would be more appropriate for it to meet in executive session without you present, or (iii) there exists, with respect to the subject of the meeting or the documents provided to the Board, an actual conflict of interest between the Company and the Icahn Group.

You acknowledge and understand that there will be no compensation in connection with this role and you will not be entitled to participate in any of the Company's benefit plans. To the extent any classification is required in connection with any reimbursement or deemed payment to you from the Company, you also acknowledge and understand that you will be an independent contractor to, not an employee of, the Company.

In connection with your role as Board Observer, you will be furnished with information concerning the Company in accordance with the terms of the confidentiality agreement in the form attached to this Agreement as Exhibit A (the "Confidentiality Agreement"), which you and the Icahn

Group agree to execute and deliver to the Company. The Company will execute and deliver the Confidentiality Agreement to the Icahn Group substantially contemporaneously with the execution and delivery of the Agreement by you and the Icahn Group. At any time that you are a Board Observer, the Board shall not adopt a policy precluding members of the Board or you from speaking to Carl Icahn with respect to non-privileged matters (upon the advice of internal or outside counsel), and the Company confirms that it will advise members of the Board that they may, but are not obligated to, speak to Carl Icahn with respect to non-privileged matters (but subject to the Confidentiality Agreement), if they are willing to do so and subject to their fiduciary duties and compliance with all written policies, procedures, processes, codes, rules, standards and guidelines applicable to all non-employee Board members and of which the Icahn Group has been provided written copies in advance (or which have been filed with the United States Securities and Exchange Commission (the "SEC") or posted on the Company's website), including the Company's Principles of Business Conduct, Code of Business Conduct and Ethics for Members of the Board of Directors, Principles of Corporate Governance of the Board of Directors, Political Engagement Policy, Insider Trading Policy, Related Person Transaction Approval Policy, and other corporate governance policies (collectively, the "Company Policies"), but may caution them regarding specific matters, if any, that involve conflicts between the Company and the Icahn Group or involve any privileged matters. Further, the Icahn Group acknowledges that it is aware that its obligations under the federal securities laws (as well as stock exchange regulations) prohibit any person who has material, non-public information concerning the Company, from trading, purchasing or selling the Company's securities when in possession of such information and from communicating such information to any other person or entity under circumstances in which it is reasonably foreseeable that such person or entity is likely to purchase or sell such securities in reliance upon such information.

You agree that the confidentiality obligations are necessary for the reasonable protection of the Company and its affiliates, and that these restraints are reasonable with respect to subject matter. You acknowledge and agree that if for any reason any of the provisions of this Agreement (including your confidentiality obligations) are not performed in accordance with their specific terms or are otherwise breached, immediate and irreparable harm or injury would be caused , for which monetary damages would be an insufficient remedy for the Company and equitable enforcement of the covenant would be proper. You agree that the Company, in addition to any other remedies available to it, will be entitled to preliminary and permanent injunctive relief against any breach by you of any of such covenants, without the necessity of showing actual monetary damages or the posting of a bond or other security. You and the Company further agree that, in the event that any provision of this Agreement is determined by any court to be unenforceable by reason of its being extended over too great a time, that provision will be deemed to be modified to permit its enforcement to the maximum extent permitted by law. You further covenant that you will not challenge the reasonableness of any of the provisions contained herein and that you will reimburse the Company and its affiliates for all costs (including reasonable attorneys' fees) incurred in connection with any action to enforce any of the provisions of this Agreement if the Company or its affiliates prevails on any material issue involved in such dispute or if you challenge the enforceability or reasonableness of any of the provisions of this Agreement.

This Agreement and your service as Board Observer may be terminated by either party any time upon written notice to the other party.

The parties hereto additionally agree as follows:

From and after the date hereof, until the later of (x) 30 days after the termination of this Agreement and (y) January 30, 2026 (the "Standstill Period"), no member of the Icahn Group shall,

directly or indirectly, and each member of the Icahn Group shall cause each of the Icahn Affiliates and Associates not to, directly or indirectly:

(i) acquire, offer or propose to acquire any shares of common stock, $6.50 par value per share, of the Company ("Common Shares") (or beneficial ownership thereof), or rights or options to acquire any Common Shares (or beneficial ownership thereof) if after any such case, immediately after the taking of such action the Icahn Group, together with its respective Icahn Affiliates, would in the aggregate, have beneficial ownership of more than 4.9% of the then outstanding Common Shares; provided that, for purposes of this subsection (i), no person shall be, or be deemed to be, the "beneficial owner" of, or to "beneficially own," any securities beneficially owned by any director of the Company to the extent such securities were acquired directly from the Company by such director as or pursuant to director compensation for serving as a director of the Company;

(ii) form or join in a partnership, limited partnership, syndicate or a "group" as defined under Section 13(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), with respect to the securities of the Company;

(iii) present (or request to present) at any annual meeting or any special meeting of the Company's shareholders, any proposal for consideration for action by shareholders or engage in any solicitation of proxies or consents or become a "participant" in a "solicitation" (as such terms are defined in Regulation 14A under the Exchange Act) of proxies or consents (including, without limitation, any solicitation of consents that seeks to call a special meeting of shareholders) or, except as provided in this Agreement, otherwise publicly propose (or publicly request to propose) any nominee for election to the Board or seek representation on the Board or the removal of any member of the Board;

(iv) grant any proxy, consent or other authority to vote with respect to any matters (other than to the named proxies included in the Company's proxy card for any annual meeting or special meeting of shareholders) or deposit any Common Shares in a voting trust or subject them to a voting agreement or other arrangement of similar effect (excluding customary brokerage accounts, margin accounts, prime brokerage accounts and the like);

(v) call or seek to call any special meeting of the Company or action by consent resolutions;

(vi) institute, solicit, assist or join, as a party, any litigation, arbitration or other proceeding against or involving the Company (other than to enforce the provisions of this Agreement) or make any request under Section 624 of the New York Business Corporation Law or other applicable legal provisions regarding inspection of books and records or other materials (including stocklist materials) of the Company or any of its subsidiaries;

(vii) separately or in conjunction with any other person in which it is or proposes to be either a principal, partner or financing source or is acting or proposes to act as broker or agent for compensation, submit a proposal for or offer of (with or without conditions), any Extraordinary Transaction (as defined below); provided that the Icahn Group shall be permitted to sell or tender their Common Shares, and otherwise receive consideration, pursuant to any Extraordinary Transaction which is made for all Common Shares and is

available on the same terms to the holders of all Common Shares; and provided further that (A) if a third party (other than the Icahn Group or an Icahn Affiliate) commences a tender offer or exchange offer for all of the outstanding Common Shares that is not rejected by the Board in its Recommendation Statement on Schedule 14D-9, then the Icahn Group shall similarly be permitted to make an offer for the Company or commence a tender offer or exchange offer for all of the outstanding Common Shares at the same or higher consideration per share, provided that the foregoing (y) will not relieve the Icahn Group of its obligations under the Confidentiality Agreement and (z) will not be deemed to require the Company to make any public disclosures and (B) the Company may waive the restrictions in this Agreement with the approval of the Board. "Extraordinary Transaction" means, collectively, any of the following involving the Company or any of its subsidiaries or its or their securities or all or substantially all of the assets or businesses of the Company and its subsidiaries: any tender offer or exchange offer, merger, acquisition, business combination, combination or majority share acquisition, reorganization, restructuring, recapitalization, sale or acquisition of material assets, or liquidation or dissolution;

(viii) seek, or encourage any person, to submit nominations in furtherance of a "contested solicitation" for the election or removal of directors with respect to the Company or, except as expressly provided in this Agreement, seek, encourage or take any other action with respect to the election or removal of any directors;

(ix) make any public communication in opposition to (A) any merger, acquisition, recapitalization, restructuring, disposition, distribution, spin-off, asset sale, joint venture or other business combination or (B) any financing transaction, in each case involving the Company;

(x) seek to advise, encourage, support or influence any person with respect to the voting or disposition of any securities of the Company at any annual meeting or special meeting of shareholders;

(xi) make any public proposal or request with respect to (A) controlling, changing or influencing the Board or management of the Company or its subsidiaries, including plans or proposals relating to any change in the number or term of directors or the filling of any vacancies on the Board, (B) any material change in the capitalization, stock repurchase programs and practices, capital allocation programs and practices or dividend policy of the Company or its subsidiaries, (C) any other material change in the Company's management, business or corporate or governance structure or (D) any waiver, amendment or modification to the Company's Articles of Incorporation or Bylaws, operations, business, corporate strategy, corporate structure, capital structure or allocation, share repurchase or dividend policies or other policy;

(xii) publicly disclose any intention, plan or arrangement inconsistent with any provision of this Agreement; or

(xiii) encourage or support any other person to take any of the actions described in this Agreement that the Icahn Group is restricted from doing.

Subject to applicable law, from the date of this Agreement until the end of the Standstill Period, (i) neither a member of the Icahn Group nor any of the Icahn Affiliates or Associates (including such persons' officers, directors and persons holding substantially similar positions however titled) shall make, or cause to be made, by press release or similar public statement, including to the press or media (including social media), or in an SEC or other public filing, any statement or announcement that disparages (as distinct from objective statements reflecting business criticism that do not address employees, officers or directors individually or as a group) the Company or the Company's respective current or former officers or directors and (ii) neither the Company nor any of its Affiliates or Associates (including such persons' officers, directors and persons holding substantially similar positions however titled) shall make, or cause to be made, by press release or similar public statement, including to the press or media (including social media), or in an SEC or other public filing, any statement or announcement that disparages (as distinct from objective statements reflecting business criticism that do not address employees, officers or directors individually or as a group) any member of the Icahn Group or Icahn Affiliates or any of their respective current or former officers or directors. For purposes of this Agreement, (A) the term "Affiliate" shall have the meaning set forth in Rule 12b-2 promulgated by the SEC under the Exchange Act, and the term "Icahn Affiliate" shall mean such Affiliates that are controlled by the members of the Icahn Group, and (B) the term "Associate" shall mean (A) any trust or other estate in which such person has a substantial beneficial interest or as to which such person serves as trustee or in a similar fiduciary capacity, and (B) any relative or spouse of such person, or any relative of such spouse, who has the same home as such person or who is a director or officer of such person or of any of its parents or subsidiaries.

For the avoidance of doubt, that certain Director Appointment and Nomination Agreement dated as of February 12, 2024 by and among the Icahn Group, the Company and the New Independent Director is terminated effective as of the date hereof.

For the avoidance of doubt, the Company and the Icahn Group acknowledge and agree that the Company will not nominate Hunter C. Gary to stand for election as a director at the 2026 annual meeting of shareholders of the Company.

This letter agreement will be governed by the laws of the State of New York, without regard to any conflicts of laws principles that would result in the application of the laws of any other jurisdiction.

This Agreement and the Confidentiality Agreement contain the entire understanding of the parties with respect to the subject matter hereof and may be amended only by an agreement in writing executed by the parties hereto.

This Agreement may be executed (including by facsimile or PDF) in two or more counterparts which together shall constitute a single agreement.

This Agreement shall not be assignable by any of the parties to this Agreement. This Agreement, however, shall be binding on successors of the parties hereto.

This Agreement is solely for the benefit of the parties hereto and is not enforceable by any other persons.

[The remainder of this page intentionally left blank.]

Please confirm your acceptance of your appointment to the position described above by signing in the space provided below and returning. Formalities aside, we are pleased to have you as Board Observer.

Sincerely,

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ William J. Fehrman
Name: William J. Fehrman
Title: Chair, President and Chief Executive Officer

Agreed and accepted as of the date first written above:

ICAHN GROUP

CARL C. ICAHN

/s/ Carl C. Icahn
CARL C. ICAHN

ANDREW TENO

/s/ Andrew Teno
ANDREW TENO

ICAHN PARTNERS LP

By: /s/ Jesse Lynn
Name: Jesse Lynn
Title: Chief Operating Officer

ICAHN PARTNERS MASTER FUND LP

By: /s/ Jesse Lynn
Name: Jesse Lynn
Title: Chief Operating Officer

ICAHN ENTERPRISES G.P. INC.

By: /s/ Ted Papapostolou
Name: Ted Papapostolou
Title: Chief Financial Officer

ICAHN ENTERPRISES HOLDINGS L.P.

By: Icahn Enterprises G.P. Inc., its general partner

By: /s/ Ted Papapostolou
Name: Ted Papapostolou
Title: Chief Financial Officer

IPH GP LLC

By: /s/ Ted Papapostolou
Name: Ted Papapostolou
Title: Chief Financial Officer

ICAHN CAPITAL LP

By: /s/ Jesse Lynn
Name: Jesse Lynn
Title: Chief Operating Officer

ICAHN ONSHORE LP

By: /s/ Jesse Lynn
Name: Jesse Lynn
Title: Chief Operating Officer

ICAHN OFFSHORE LP

By: /s/ Jesse Lynn
Name: Jesse Lynn
Title: Chief Operating Officer

BECKTON CORP

By: /s/ Ted Papapostolou
Name: Ted Papapostolou
Title: Vice President

SCHEDULE A

Carl C. Icahn

Andrew Teno

Icahn Partners LP

Icahn Partners Master Fund LP

Icahn Enterprises G.P. Inc.

Icahn Enterprises Holdings L.P.

IPH GP LLC

Icahn Capital LP

Icahn Onshore LP

Icahn Offshore LP

Beckton Corp.

EXHIBIT A
CONFIDENTIALITY AGREEMENT

December 20, 2025

To: Each of the persons or entities listed on Schedule A (the "Icahn Group" or "you")

Ladies and Gentlemen:

This letter agreement shall become effective upon the execution of a letter agreement between American Electric Power Company, Inc. (the "Company") and Andrew Teno and the Icahn Group related to the appointment of Andrew Teno as a Board Observer to the Board of Directors of the Company. Capitalized terms used but not otherwise defined herein shall have the meanings given to such terms in the Board Observer Agreement (the "Board Observer Agreement"), dated as of December 20, 2025, among the Company, Andrew Teno and the Icahn Group. The Company understands and agrees that, subject to the terms of, and in accordance with, this letter agreement, the Board Observer may, if and to the extent he desires to do so, disclose non-privileged information he obtains while serving as a non-voting observer to the Board to you and your Representatives (as hereinafter defined), and may discuss such information with any and all such persons, subject to the terms and conditions of this letter agreement, and that other members of the Board may similarly disclose information to you if they wish to do so, subject to the Company Policies. As a result, you may receive certain non-public information regarding the Company. You acknowledge that this information is proprietary to the Company and may include trade secrets or other business information the disclosure of which could harm the Company. In consideration for, and as a condition of, the information being furnished to you and your agents, representatives, attorneys, advisors, directors, officers or employees (collectively, the "Representatives"), subject to the restrictions in paragraph 2, you agree to treat any and all information concerning or relating to the Company or any of its subsidiaries or current or former affiliates that is furnished to you or your Representatives (regardless of the manner in which it is furnished, including in written or electronic format or orally, gathered by visual inspection or otherwise) by the Board Observer or by or on behalf of the Company or any Company Representative (as defined below), including discussions or matters considered in meetings of the Board or Board committees, together with any notes, analyses, reports, models, compilations, studies, interpretations, documents, records or extracts thereof containing, referring, relating to, based upon or derived from such information, in whole or in part (collectively, "Evaluation Material"), in accordance with the provisions of this letter agreement, and to take or abstain from taking the other actions hereinafter set forth.

The term "Evaluation Material" does not include information that (i) is or has become generally available to the public other than as a result of a direct or indirect disclosure by you or your Representatives in violation of this letter agreement or any other obligation of confidentiality, (ii) was within your or any of your Representatives' possession on a non-confidential basis prior to its being furnished to you by the Board Observer or by or on behalf of the Company, any of its subsidiaries or their respective agents, representatives, attorneys, advisors, directors, officers or employees (collectively, the "Company Representatives"), or (iii) is received from a source other than the Board Observer, the Company or any of the Company Representatives; *provided,* that in the case of (ii) or (iii) above, the source of such information was not believed by you, after reasonable inquiry, to be bound by a confidentiality agreement with or other contractual, legal or fiduciary obligation of confidentiality to the Company, any of its subsidiaries or any other person with respect to such information at the time the information was disclosed to you.

You and your Representatives will, and you will cause your Representatives to, (a) keep the Evaluation Material strictly confidential, (b) not disclose any of the Evaluation Material in any manner whatsoever without the prior written consent of the Company and (c) use the Evaluation Material only in connection with monitoring and advising you on your investment in the Company; *provided, however,* that you may privately disclose any of such information: (A) to your Representatives (i) who need to know such information for the purpose of advising you on your investment in the Company and (ii) who are informed by you of the confidential nature of such information and agree to be bound by the terms of this Agreement as if they were a party hereto; *provided, further,* that you will be responsible for any violation of this letter agreement by your Representatives as if they were parties to this letter agreement; and (B) to the Company and the Company Representatives. It is understood and agreed that the Board Observer shall not disclose to you or your Representatives any Privileged Information (as defined below) that may be included in the Evaluation Material. "Privileged Information" as used in this letter agreement shall be solely and exclusively limited to the advice provided by legal counsel and any discussions, deliberations or materials concerning such advice or which would otherwise be subject to legal privileges and protections and shall not include factual information or the formulation or analysis of business strategy solely to the extent that it is not protected by the attorney-client, attorney work product or other legal privilege.

In the event that you or any of your Representatives are required by applicable subpoena, legal process or other legal requirement to disclose any of the Evaluation Material, you will (a) promptly notify (except where such notice would be legally prohibited) the Company in writing by email, facsimile and certified mail so that the Company may seek a protective order or other appropriate remedy (and if the Company seeks such an order, you will provide such cooperation as the Company shall reasonably request), at its cost and expense and (b) produce or disclose only that portion of the Evaluation Material which your outside legal counsel of national standing advises you in writing is legally required to be so produced or disclosed and you inform the recipient of such Evaluation Material of the existence of this letter agreement and the confidential nature of such Evaluation Material. In no event will you or any of your Representatives oppose action by the Company to obtain a protective order or other relief to prevent the disclosure of the Evaluation Material or to obtain reliable assurance that confidential treatment will be afforded the Evaluation Material. For the avoidance of doubt, it is understood that there shall be no "legal requirement" requiring you to disclose any Evaluation Material solely by virtue of the fact that, absent such disclosure, you would be prohibited from purchasing, selling, or engaging in derivative or other voluntary transactions with respect to the Common Shares of the Company or otherwise proposing or making an offer to do any of the foregoing, or you would be unable to file any proxy or other solicitation materials in compliance with Section 14(a) of the Exchange Act or the rules promulgated thereunder.

You acknowledge that (a) none of the Company or any of the Company Representatives makes any representation or warranty, express or implied, as to the accuracy or completeness of any Evaluation Material, and (b) none of the Company or any of the Company Representatives shall have any liability to you or to any of your Representatives relating to or resulting from the use of the Evaluation Material or any errors therein or omissions therefrom. You and your Representatives (or anyone acting on your or their behalf) shall not directly or indirectly initiate contact or communication with any executive or employee of the Company or any of its subsidiaries other than the Chair of the Board, the President and Chief Executive Officer, Chief Financial Officer, General Counsel or such other persons approved in writing by the foregoing or the Board concerning Evaluation Material, or to seek any information in connection therewith from any such person other than the foregoing, without the prior consent of the Company.

All Evaluation Material shall remain the property of the Company. Neither you nor any of your Representatives shall by virtue of any disclosure of or your use of any Evaluation Material acquire any rights with respect thereto, all of which rights (including all intellectual property rights) shall remain exclusively with the Company. Upon the request of the Company for any reason, you will promptly return to the Company or destroy all hard copies of the Evaluation Material and use reasonable best efforts to permanently erase or delete all electronic copies of the Evaluation Material in your or any of your Representatives' possession or control (and, upon the request of the Company, shall promptly certify to the Company that such Evaluation Material has been erased or deleted, as the case may be). Notwithstanding the foregoing, the obligation to return or destroy Evaluation Material shall not cover information (i) that is maintained on routine computer system backup tapes, disks or other backup storage devices as long as such backed-up information is not used, disclosed, or otherwise recovered from such backup devices or (ii) retained on a confidential basis solely to the extent required to comply with applicable law and/or any internal record retention requirements; provided that such materials referenced in this sentence shall remain subject to the terms of this letter agreement applicable to Evaluation Material, and you and your Representatives will continue to be bound by the obligations contained herein for as long as any such materials are retained by you or your Representatives.

You acknowledge, and will advise your Representatives, that the Evaluation Material may constitute material non-public information under applicable federal or state securities laws, and you agree that you shall not, and you shall use reasonable best efforts to ensure that your Representatives do not, trade or engage in any derivative or other transaction in the Common Shares or any of the Company's other securities on the basis of such information in violation of such laws.

You hereby represent and warrant to the Company that (i) you have all requisite corporate, entity or other power and authority to execute and deliver this letter agreement and to perform your obligations hereunder, (ii) this letter agreement has been duly authorized, executed and delivered by you, and is a valid and binding obligation, enforceable against you in accordance with its terms, (iii) this letter agreement will not result in a violation of any terms or conditions of any agreements to which you are a party or by which you may otherwise be bound, and (iv) your entry into this letter agreement does not require approval by any owners or holders of any equity or other interest in you (except as has already been obtained).

Any waiver by the Company of a breach of any provision of this letter agreement shall not operate as or be construed to be a waiver of any other breach of such provision or of any breach of any other provision of this letter agreement. The failure of the Company to insist upon strict adherence to any term of this letter agreement on one or more occasions shall not be considered a waiver or deprive the Company of the right thereafter to insist upon strict adherence to that term or any other term of this letter agreement.

You acknowledge and agree that the value of the Evaluation Material to the Company is unique and substantial, but may be impractical or difficult to assess in monetary terms. You further acknowledge and agree that in the event of an actual or threatened violation of this letter agreement, immediate and irreparable harm or injury would be caused for which money damages would not be an adequate remedy. Accordingly, you acknowledge and agree that, in addition to any and all other remedies which may be available to the Company at law or equity, the Company shall be entitled to an injunction or injunctions to prevent breaches of this letter agreement and to enforce specifically the terms and provisions of this letter agreement exclusively in the federal or state courts of the State of New York. In the event that any action shall be brought in equity to enforce the provisions of this letter agreement, you shall not allege, and you hereby waive the defense, that there is an adequate remedy at law.

Each of the parties hereto (a) consents to submit itself to the personal jurisdiction of the federal or state courts of the State of New York in the event any dispute arises out of this letter agreement or the transactions contemplated by this letter agreement, (b) agrees that it shall not attempt to deny or defeat such personal jurisdiction by motion or other request for leave from any such court, (c) agrees that it shall not bring any action relating to this letter agreement or the transactions contemplated by this letter agreement in any court other than the federal or state courts of the State of New York, and each of the parties irrevocably waives the right to trial by jury, (d) agrees to waive any bonding requirement under any applicable law, in the case any other party seeks to enforce the terms by way of equitable relief, and (e) irrevocably consents to service of process by a reputable overnight delivery service, signature requested, to the address of such party's principal place of business or as otherwise provided by applicable law. THIS LETTER AGREEMENT SHALL BE GOVERNED IN ALL RESPECTS, INCLUDING VALIDITY, INTERPRETATION AND EFFECT, BY THE LAWS OF THE STATE OF NEW YORK APPLICABLE TO CONTRACTS EXECUTED AND TO BE PERFORMED WHOLLY WITHIN SUCH STATE WITHOUT GIVING EFFECT TO THE CHOICE OF LAW PRINCIPLES OF SUCH STATE.

This letter agreement and the Board Observer Agreement contain the entire understanding of the parties with respect to the subject matter hereof and thereof and supersedes all prior or contemporaneous agreements or understandings, whether written or oral. This letter agreement may be amended only by an agreement in writing executed by the parties hereto.

All notices, consents, requests, instructions, approvals and other communications provided for in this letter agreement and all legal process in regard to this letter agreement shall be in writing and shall be deemed validly given, made or served, if (a) given by telecopy and email, when such telecopy is transmitted to the telecopy number set forth below and sent to the email address set forth below and the appropriate confirmation is received or (b) if given by any other means, when actually received during normal business hours at the address specified in this subsection:

if to the Company:

American Electric Power Company, Inc.
1 Riverside Plaza
Columbus, OH 43215-2373
Attention: Robert Berntsen, EVP, General Counsel and Secretary
Email: rberntsen@aep.com

With copies to (which shall not constitute notice):

Gibson, Dunn & Crutcher LLP
200 Park Avenue
New York, NY 10166
Attention: Lori Zyskowski
Andrew Kaplan
Emails: lzyskowski@gibsondunn.com
akaplan@gibsondunn.com

if to the Icahn Group:

Icahn Capital LP
16690 Collins Avenue, Penthouse Suite
Sunny Isles Beach, FL 33160
Attention: Jesse Lynn, Chief Operating Officer
Email: jlynn@sfire.com

If at any time subsequent to the date hereof, any provision of this letter agreement shall be held by any court of competent jurisdiction to be illegal, void or unenforceable, such provision shall be of no force and effect, but the illegality or unenforceability of such provision shall have no effect upon the legality or enforceability of any other provision of this letter agreement.

This letter agreement may be executed (including by facsimile or PDF) in two or more counterparts which together shall constitute a single agreement.

This letter agreement and the rights and obligations herein may not be assigned or otherwise transferred, in whole or in part, by you without the express written consent of the Company. This letter agreement, however, shall be binding on successors of the parties to this letter agreement.

This letter agreement shall expire three (3) years from the date on which the Board Observer ceases to be Board Observer; except that you shall maintain in accordance with the confidentiality obligations set forth in this letter agreement any Evaluation Material (i) constituting trade secrets for such longer time as such information constitutes a trade secret of the Company as defined under 18 U.S.C. § 1839(3) and/or (ii) retained pursuant to this Agreement.

No licenses or rights under any patent, copyright, trademark, or trade secret are granted or are to be implied by this letter agreement.

Each of the parties acknowledges that it has been represented by counsel of its choice throughout all negotiations that have preceded the execution of this letter agreement, and that it has executed the same with the advice of said counsel. Each party and its counsel cooperated and participated in the drafting and preparation of this agreement and the documents referred to herein, and any and all drafts relating thereto exchanged among the parties shall be deemed the work product of all of the parties and may not be construed against any party by reason of its drafting or preparation. Accordingly, any rule of law or any legal decision that would require interpretation of any ambiguities in this agreement against any party that drafted or prepared it is of no application and is hereby expressly waived by each of the parties, and any controversy over interpretations of this agreement shall be decided without regards to events of drafting or preparation. The term “including” shall in all instances be deemed to mean “including without limitation.” In all instances, the term “or” shall not be deemed to be exclusive.

[Signature Pages Follow]

Please confirm your agreement with the foregoing by signing and returning one copy of this letter agreement to the undersigned, whereupon this letter agreement shall become a binding agreement between you and the Company.

Very truly yours,

AMERICAN ELECTRIC POWER COMPANY, INC.

By: ____
Name: William J. Fehrman
Title: Chair, President and Chief Executive Officer

Accepted and agreed as of the date first written above:

CARL C. ICAHN

Carl C. Icahn

ANDREW TENO

Andrew Teno

ICAHN PARTNERS LP

By:
Name: Jesse Lynn
Title: Chief Operating Officer

ICAHN PARTNERS MASTER FUND LP

By:
Name: Jesse Lynn
Title: Chief Operating Officer

ICAHN ENTERPRISES G.P. INC.

By:
Name: Ted Papapostolou
Title: Chief Financial Officer

ICAHN ENTERPRISES HOLDINGS L.P.

By: Icahn Enterprises G.P. Inc., its general partner

By: ____
Name: Ted Papapostolou
Title: Chief Financial Officer

IPH GP LLC

By: ____
Name: Ted Papapostolou
Title: Chief Financial Officer

ICAHN CAPITAL LP

By: ____
Name: Jesse Lynn
Title: Chief Operating Officer

ICAHN ONSHORE LP

By: ____
Name: Jesse Lynn
Title: Chief Operating Officer

ICAHN OFFSHORE LP

By: ____
Name: Jesse Lynn
Title: Chief Operating Officer

BECKTON CORP

By: ____
Name: Ted Papapostolou
Title: Vice President

SCHEDULE A

Carl C. Icahn

Andrew Teno

Icahn Partners LP

Icahn Partners Master Fund LP

Icahn Enterprises G.P. Inc.

Icahn Enterprises Holdings L.P.

IPH GP LLC

Icahn Capital LP

Icahn Onshore LP

Icahn Offshore LP

Beckton Corp.

AMERICAN ELECTRIC POWER EXECUTIVE SEVERANCE PLAN

SEVERANCE, RELEASE OF ALL CLAIMS AND NONCOMPETITION AGREEMENT

1. This **Severance, Release of All Claims and Noncompetition Agreement** ("Agreement") is entered into by and between **David M. Feinberg**, as "Employee", and American Electric Power Company Inc., hereinafter referred to, together with all its past, present and future subsidiaries, affiliates, divisions, organizations and related entities, and any successor or assigns of any of the foregoing, as the "Company".

2. **Severance Allowance**. Provided the Employee timely executes, returns, and does not revoke this Agreement and continues to provide services to the Company up to and including the Termination Date (also referred to in this Agreement as a "Separation Date"), the Company shall provide the following consideration:

(a) to Employee (or Employee's estate) a salary and bonus severance in the amount of $1,405,495.00 (the "Severance Amount"). The Company shall pay the Severance Amount to Employee according to the following payment schedule:

(i) $702,747.50 as of the first regular payroll date of the Company that coincides with or immediately follows the date that is six months after the Separation Date; and

(ii) the balance of such Severance Amount to be paid in 13 equal bi-weekly installments of $54,057.50 paid over the 13 subsequent regular payroll dates of the Company following the payroll date referenced in Section 2(a)(i).

Payment under this Section 2(a) shall be made by direct deposit, by mailing to the last address provided by Employee to the Company, or by such other reasonable method as determined by the Company. Each payment shall be subject to such deductions as required by law.

(b) Partial vesting shall apply to Employee's outstanding Performance Share Awards and RSU Awards, as further described in the Summary of Benefits from Andrew R. Carlin, Director Compensation & Executive Benefits, to Employee, a copy of which is attached hereto as Exhibit A (the "Summary of Benefits").

3. **Consideration**. Employee acknowledges that certain of the benefits described in this Agreement are benefits to which they would not be entitled but for this Agreement.

4. **Release and Waiver of Claims**.

(A) Release and Waiver. Employee together with their heirs, executors, administrators, successors, assigns and personal representatives (collectively referred to as "Releasing Parties"), hereby release and forever discharge the Company, all its past, present, and future officers, directors, members, employees, and agents, in both their individual and representative capacities,

and the Company's long-term disability plans (including any trustees, custodians and administrators engaged in connection with the administration of claims or assets maintained in connection with any such plans) (collectively referred to as "Released Parties") of and from any and all legal, equitable, and administrative claims and demands of every name, type, act and nature, arising out of or existing by reason of any known or unknown act or inaction whatsoever and occurring directly or indirectly as a result of or prior to execution of this Agreement. This release includes, but is not limited to, any claims, charges, complaints, grievances, causes of action (known or unknown), demands, injuries (whether personal, emotional or other), unfair labor practices, or suits arising, directly or indirectly, out of Employee's employment with and/or separation of employment from the Company, and includes, but is not limited to claims, charges, complaints, actions, grievances, demands or suits which may be, have, or might have been asserted, whether in contract or in tort, and whether under common law or under federal, state or local statute, regulation or ordinance. Claims, actions and demands released herein include but are not limited to those based on allegations of wrongful discharge, retaliation, personal injury and/or breach of contract; those arising under federal, state or local employment discrimination, fair employment practices, and/or wage and hour laws; and for West Virginia employees, those arising under the West Virginia Human Rights Act; those arising under Title VII of the Civil Rights Act of 1964, the Civil Rights Act of 1866, as amended, the Fair Labor Standards Act, the Age Discrimination in Employment Act of 1967 ("ADEA"), the Older Workers' Benefit Protection Act, the Rehabilitation Act of 1973, and the Americans With Disabilities Act ("ADA") (all as amended); those arising under the Uniformed Services Employment and Re-employment Rights Act of 1994 ("USERRA"), the Worker Adjustment and Retraining Notification Act ("WARN"), the Labor Management Relations Act ("LMRA"), the National Labor Relations Act ("NLRA"), and the Family and Medical Leave Act ("FMLA"); and those arising under applicable securities laws. Also released are any claims and demands related to entitlement to long-term disability benefits under any Company long-term disability plan. Employee and the Releasing Parties are waiving any right to recover any individual relief from the Company and the Released Parties (including back pay, front pay, reinstatement or other legal or equitable relief) in any charge, complaint, lawsuit or other proceeding brought by Employee, the Releasing Parties, or on either's behalf against the Company or the Released Parties pertaining to events occurring directly or indirectly as the result of or prior to execution of this Agreement. This release and waiver shall be construed as broadly as the law permits.

(B) Excluded. This release and waiver does not apply to (i) claims for unemployment or worker's compensation benefits; (ii) any vested rights under Company pension and savings plans (401k); (iii) claims for benefits or reimbursement under any health and welfare benefit plans (medical, dental and vision) under the terms of such plans; (iv) claims for vested balances and payments under non-qualified deferred compensation plans; (v) claims which controlling law holds cannot be waived or released by private agreement; (vi) rights or claims for indemnification, advancement, or exculpation by virtue of Employee's services as an officer or director of the Company, whether arising under the Company's certificates of incorporation or bylaws or any agreement, policy or governing document benefitting the Employee to which the Company is a party; or (vii) rights or claims arising under this Agreement, including, without limitation, with respect to Employee's right to receive any of the payments and benefits under Section 2 above or the Summary of Benefits attached hereto.

5. **Protected Activity**. (A) Employee understands and acknowledges that nothing in this Agreement prohibits, penalizes, or otherwise discourages them from reporting, providing testimony regarding, or otherwise communicating any nuclear safety concern, workplace safety concern, or public safety concern to the U.S. Nuclear Regulatory Commission (NRC) or the U.S. Department of Labor (DOL). Employee further understands and acknowledges that the provisions of this Agreement are not intended to restrict their communication with, or full cooperation in, proceedings or investigations by any agency relating to nuclear regulatory or safety issues. Employee understands that nothing in the Agreement waives their right to file a claim with the DOL pursuant to Section 211 of the Energy Reorganization Act, but the Employee expressly waives their and the Releasing Parties' right to recover any and all damages or other equitable relief, including, but not limited to reinstatement, back pay, front pay, compensatory damages, attorney fees or costs, that may be awarded to the Employee or the Releasing Parties by the DOL as a result of such a claim.

(B) Nothing in this Agreement (including but not limited to the release and waiver of claims and the confidentiality, cooperation, non-disparagement, return of property and any other limiting provisions) (1) affects or limits Employee's right to challenge the validity of this Agreement under the ADEA or the Older Workers Benefit Protection Act (where Employee is age 40 or older) or (2) prevents Employee from filing a charge or complaint with, from communicating with or from participating in an investigation or proceeding conducted by, the Equal Employment Opportunity Commission, the Occupational Safety and Health Administration, the National Labor Relations Board, the Securities and Exchange Commission, the Internal Revenue Service, the Department of Justice or any other federal, state or local agency charged with the enforcement of any laws, including providing documents or other information. Specifically, pursuant to SEC Rule 21F-7, nothing herein or in any other agreement, policy, or directive impedes or restricts Employee from communicating directly with the Securities and Exchange Commission, without prior notice to or approval from the AEP System Companies, concerning a violation or potential violation of a federal securities law or rule. This Agreement does not limit any right Employee or Releasing Parties may have, where eligible, to receive an award from a government agency (and not the Company or the Released Parties) for information provided to the government agency.

6. **Agreement Not to Compete.** Without American Electric Power Service Corporation's prior written consent, Employee agrees not to, during the 12-month period following the Employee's Termination Date (the "Restricted Period"), for any reason, directly or indirectly either as principal, agent, manager, employee, partner, shareholder, director, officer, consultant or otherwise, become engaged or involved, in a manner that materially relates to or is similar in nature to the specific duties performed by the Employee at any time during their employment with the Company, in any business (other than as a less-than three percent (3%) equity owner of any corporation traded on any national, international or regional stock exchange or in the over-the-counter market) that directly competes with the Company in

(i) the business of the harnessing, production, transmission, distribution, marketing or sale of electricity; or the development or operation of transmission facilities or power generation facilities; or

(ii) any other business in which the Company is engaged at the termination of the Employee's employment with the Company.

The provisions of this Section 6 shall be limited in scope and be effective only within one or more of the following geographical areas: (A) any state in the United States where the Company has at least U.S. $25 million in capital deployed as of the Employee's Termination Date; or (B) any state or country with respect to which the Company conducted a business, which, or oversight of which, constituted any part of the Employee's employment. The parties intend the above geographical areas to be completely severable and independent, and any invalidity or unenforceability of this Agreement with respect to any one area shall not render this Agreement unenforceable as applied to any one or more of the other areas. Nothing in this Section 6 shall be construed to prohibit the Employee being retained during the Restricted Period in a capacity as an attorney licensed to practice law, or to restrict the Employee from providing advice and counsel in such capacity, in any jurisdiction where such prohibition or restriction is contrary to law.

Exhibit C contains a description of American Electric Power Service Corporation's prior written consent, if any, under this Section 6.

7. **Cessation of Employment and (where applicable) LTD Benefits**. If Employee has any claim of any benefit entitlement attributable to a disability of Employee, Employee further acknowledges and understands that, as a consequence of accepting the benefits referenced in this Agreement, and signing this Agreement, Employee's employment with the Company is terminated, the payment (if applicable) of any long-term disability benefits will cease, any claim of entitlement to long-term disability benefits is released, and that any existing reduction of employee contributions toward the cost of medical, dental, life and any other coverages will also cease, subject to Employee's rights to continuation of coverages pursuant to applicable law. In any event, Employee acknowledges that Employee shall no longer be entitled to any continued employment with the Company.

8. **Resignation of Director, Officer and Manager Positions**. To the extent Employee has retained any director, officer and/or manager positions with the Company subsequent to Employee's termination of employment, and to the extent Employee has not already done so, Employee, by executing this Agreement on the date set forth below, hereby resigns, effective immediately, from any and all director, officer and/or manager positions with the Company.

9. **Acknowledgement of Covenants**. Employee reaffirms that Employee is bound by and shall comply with the provisions in Article VI of the American Electric Power Executive Severance Plan, as amended and restated (the "Executive Severance Plan"), a copy of which is attached hereto as Exhibit B, during and after the Employee's employment with the Company.

10. **No Admission of Liability**. Employee understands that the Company believes that Employee has no valid claim against the Company and that this Agreement is being offered to give Employee a source of income and benefits while they attempt to obtain other employment. The fact that this Agreement is offered to the Employee in the first place will not be understood as an indication that the Company believes that Employee has been injured, discriminated against or treated unlawfully in any respect.

11. **Re-employment**. Employee agrees and understands that they will not seek re-employment with the Company, and that this Agreement shall act as a complete bar to any claim of entitlement to employment or re-employment by the Company.

12. **Entire Agreement**. Employee and the Company acknowledge that this Agreement and the exhibits hereto contains the entire agreement and understanding of the parties and that no other representation or agreement of any kind whatsoever has been made to Employee by the Company or by any other person or entity to cause Employee to sign this Agreement.

13. **Applicable Law** . This Agreement shall be governed and interpreted in accordance with the laws of Ohio and applicable federal law.

14. **Severability**. If any provision of this Agreement is determined to be invalid or unenforceable, the Company and Employee agree that such determination shall not affect the other provisions and that all other provisions shall be enforced as if the invalid provision were not a part of this Agreement.

15. **EMPLOYEE NOTICE: PLEASE READ CAREFULLY BEFORE SIGNING THIS AGREEMENT.**

You have twenty-one (21) calendar days within which to consider this Agreement. You may not sign this Agreement until after your Separation Date. You may execute (accept) this Agreement at any time after your Separation Date and within the twenty-one (21) day review period by signing and dating this Agreement and then scanning and emailing it to Andrew R. Carlin at arcarlin@aep.com. Should you sign the Agreement, you have the right to revoke it, in writing, for a period of seven (7) calendar days ("revocation period") after you sign it. Any such revocation should be provided to Andrew R. Carlin at arcarlin@aep.com. This Agreement shall not become effective or enforceable until the revocation period has expired. However, if you sign this Agreement and do not exercise the right to revoke, this Agreement will immediately become a binding and enforceable contract.

You are advised to consult with an attorney prior to signing this Agreement. You may have rights or claims arising under the Age Discrimination in Employment Act and/or the Older Workers Benefit Protection Act. If you work in West Virginia, you are further advised that the toll-free number of the West Virginia State Bar Association is 1-800-642-3617.

16. **Capitalized Terms and Definitions**. Unless specifically defined herein, capitalized terms in this Agreement shall have the definition described in the Executive Severance Plan. Employee acknowledges that they have received a copy of the Executive Severance Plan.

17. **Conclusion.** The parties have read the foregoing Severance, and Release of All Claims and Noncompetition Agreement and fully understand it. They now voluntarily sign this Agreement on the date indicated, signifying their agreement and willingness to be bound by its terms.

Employee **American Electric Power Company, Inc.**

/s/ David M. Feinberg By /s/ Phillip R. Ulrich
David M. Feinberg Phillip R. Ulrich

Title: EVP, Chief HR Officer

Dated: 8/8/2025 Dated: 8/8/2025

Exhibit C

SECTION 6 CONSENT

Pursuant to Section 6 of the Agreement, American Electric Power Service Corporation gives its written consent to the following activity(ies) by Employee:

1. To become employed as General Counsel with Ameren Corporation and any of its subsidiaries and affiliates, including but not limited to holding any officer or director positions associated with Employee's employment with Ameren Corporation.

End of Consent.

Subsidiaries of
American Electric Power Company, Inc.
As of December 31, 2025

Each company shown indented is a subsidiary of the company immediately above which is not indented to the same degree. Subsidiaries not indented are directly owned by American Electric Power Company, Inc.

Name of Company	Location of Incorporation
American Electric Power Service Corporation	New York
AEP Energy Supply LLC	Delaware
AEP Energy Partners, Inc	Delaware
AEP Generation Resources Inc.	Delaware
AEP Generating Company	Ohio
AEP Transmission Holding Company, LLC	Delaware
AEP Transmission Company, LLC	Delaware
AEP Oklahoma Transmission Company, Inc	Oklahoma
AEP West Virginia Transmission Company, Inc	West Virginia
Midwest Transmission Holdings, LLC	Delaware
AEP Indiana Michigan Transmission Company, Inc	Indiana
AEP Ohio Transmission Company, Inc	Ohio
AEP Texas Inc.	Delaware
AEP Texas Central Transition Funding III LLC	Delaware
AEP Texas North Generation Company LLC	Delaware
AEP Texas Restoration Funding, LLC	Delaware
Appalachian Power Company	Virginia
Appalachian Consumer Rate Relief Funding LLC	Delaware
Appalachian Consumer Rate Relief Funding II LLC	Delaware
Appalachian Power Recovery Funding LLC	Delaware
Indiana Michigan Power Company	Indiana
Kentucky Power Company	Kentucky
Kentucky Power Cost Recovery LLC	Delaware
Kingsport Power Company	Virginia
Ohio Power Company	Ohio
Ohio Valley Electric Corporation	Ohio
Indiana-Kentucky Electric Corporation	Indiana
Public Service Company of Oklahoma	Oklahoma
Southwestern Electric Power Company	Delaware
SWEPCo Storm Recovery Funding LLC	Louisiana
Wheeling Power Company	West Virginia

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-291275, 333-284963, and 333-284966) and on Form S-8 (Nos. 333-279304, 333-224973, and 333-178044) of American Electric Power Company, Inc. of our report dated February 12, 2026 relating to the financial statements, financial statement schedules and the effectiveness of internal control over financial reporting, of American Electric Power Company, Inc., which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 12, 2026

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-277662) of AEP Transmission Company, LLC of our report dated February 12, 2026 relating to the financial statements and financial statement schedule of AEP Transmission Company, LLC, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 12, 2026

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-279418) of AEP Texas Inc. of our report dated February 12, 2026 relating to the financial statements of AEP Texas Inc., which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 12, 2026

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-290611) of Appalachian Power Company of our report dated February 12, 2026 relating to the financial statements of Appalachian Power Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 12, 2026

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-290612) of Indiana Michigan Power Company of our report dated February 12, 2026 relating to the financial statements of Indiana Michigan Power Company which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 12, 2026

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-275801) of Ohio Power Company of our report dated February 12, 2026 relating to the financial statements Ohio Power Company which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 12, 2026

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-282058) of Public Service Company of Oklahoma of our report dated February 12, 2026 relating to the financial statements Public Service Company of Oklahoma which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 12, 2026

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-282060) of Southwestern Electric Power Company of our report dated February 12, 2026 relating to the financial statements Southwestern Electric Power Company which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 12, 2026

POWER OF ATTORNEY

AMERICAN ELECTRIC POWER COMPANY, INC.

Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 2025

The undersigned directors of AMERICAN ELECTRIC POWER COMPANY, INC., a New York corporation (the "Company"), do hereby constitute and appoint WILLIAM J. FEHRMAN, TREVOR I. MIHALIK and MATTHEW D. FRANSEN, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2025, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

[*Signature page to follow*]

IN WITNESS WHEREOF, each of the undersigned have signed these presents as of the "Date of Execution" set forth below.

/s/ Wiliam J. Fehrman February 10, 2026
William J. Fehrman Date of Execution

/s/ Benjamin G. S. Fowke, III February 10, 2026
Benjamin G. S. Fowke, III Date of Execution

/s/ Art A. Garcia February 10, 2026
Art A. Garcia Date of Execution

/s/ Hunter C. Gary February 10, 2026
Hunter C. Gary Date of Execution

/s/ Sandra Beach Lin February 10, 2026
Sandar Beach Lin Date of Execution

/s/ Henry P. Linginfelter February 10, 2026
Henry P. Linginfelter Date of Execution

/s/ Margaret M. McCarthy February 10, 2026
Margaret M. McCarthy Date of Execution

/s/ Daryl Roberts February 10, 2026
Daryl Roberts Date of Execution

/s/ Joseph G. Sauvage February 10, 2026
Joseph G. Sauvage Date of Execution

/s/ Daniel G. Stoddard February 11, 2026
Daniel G. Stoddard Date of Execution

/s/ Sara Martinez Tucker February 10, 2026
Sara Martinez Tucker Date of Execution

/s/ Lewis F. Von Thaer February 10, 2026
Lewis F. Von Thaer Date of Execution

POWER OF ATTORNEY

AEP TRANSMISSION COMPANY, LLC

Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2025

The undersigned managers of AEP TRANSMISSION COMPANY, LLC, a Delaware limited liability company (the "Company"), do hereby constitute and appoint WILLIAM J. FEHRMAN, TREVOR I. MIHALIK and MATTHEW D. FRANSEN, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2025, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned have signed these presents as of the “Date of Execution” set forth below.

/s/ Robert B. Berntsen — February 10, 2026
Robert B. Berntsen — Date of Execution

/s/ William J. Fehrman — February 10, 2026
William J. Fehrman — Date of Execution

/s/ Trevor I. Mihalik — February 10, 2026
Trevor I. Mihalik — Date of Execution

POWER OF ATTORNEY

AEP TEXAS INC.
Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2025

The undersigned directors of AEP TEXAS INC., a Delaware corporation (the "Company"), do hereby constitute and appoint WILLIAM J. FEHRMAN, TREVOR I. MIHALIK and MATTHEW D. FRANSEN, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2025, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned have signed these presents as of the “Date of Execution” set forth below.

/s/ Robert B. Berntsen — February 10, 2026
Robert B. Berntsen — Date of Execution

/s/ William J. Fehrman — February 10, 2026
William J. Fehrman — Date of Execution

/s/ Trevor I. Mihalik — February 10, 2026
Trevor I. Mihalik — Date of Execution

/s/ Judith E. Talavera — February 10, 2026
Judith E. Talavera — Date of Execution

POWER OF ATTORNEY

APPALACHIAN POWER COMPANY
Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2025

The undersigned directors of APPALACHIAN POWER COMPANY, a Virginia corporation (the "Company"), do hereby constitute and appoint WILLIAM J. FEHRMAN, TREVOR I. MIHALIK and MATTHEW D. FRANSEN, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2025, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned have signed these presents as of the “Date of Execution” set forth below.

/s/ Robert B. Berntsen — February 10, 2026
Robert B. Berntsen — Date of Execution

/s/ William J. Fehrman — February 10, 2026
William J. Fehrman — Date of Execution

/s/ Trevor I. Mihalik — February 10, 2026
Trevor I. Mihalik — Date of Execution

/s/ Aaron D. Walker — February 10, 2026
Aaron D. Walker — Date of Execution

POWER OF ATTORNEY

INDIANA MICHIGAN POWER COMPANY

Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2025

The undersigned directors of INDIANA MICHIGAN POWER COMPANY, an Indiana corporation (the "Company"), do hereby constitute and appoint WILLIAM J. FEHRMAN, TREVOR I. MIHALIK and MATTHEW D. FRANSEN, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2025, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned have signed these presents as of the “Date of Execution” set forth below.

/s/ Steven F. Baker — February 11, 2026
Steven F. Baker — Date of Execution

/s/ Robert B. Berntsen — February 10, 2026
Robert B. Berntsen — Date of Execution

/s/ William J. Fehrman — February 10, 2026
Wiliam J. Fehrman — Date of Execution

_____ — _____
Scott A. Huebner — Date of Execution

/s/ Trevor I. Mihalik — February 10, 2026
Trevor I. Mihalik — Date of Execution

/s/ Katherine K. Runkle — February 10, 2026
Katherine K. Runkle — Date of Execution

/s/ Stephanny L. Smith — February 10, 2026
Stephanny L. Smith — Date of Execution

/s/ Andrew J. Williamson — February 10, 2026
Andrew J. Williamson — Date of Execution

POWER OF ATTORNEY

OHIO POWER COMPANY
Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2025

The undersigned directors of OHIO POWER COMPANY, an Ohio corporation (the "Company"), do hereby constitute and appoint WILLIAM J. FEHRMAN, TREVOR I. MIHALIK and MATTHEW D. FRANSEN, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2025, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned have signed these presents as of the “Date of Execution” set forth below.

/s/ Robert B. Berntsen — February 10, 2026
Robert B. Berntsen — Date of Execution

/s/ William J. Fehrman — February 10, 2026
William J. Fehrman — Date of Execution

/s/ Trevor I. Mihalik — February 10, 2026
Trevor I. Mihalik — Date of Execution

/s/ Marc D. Reitter — February 10, 2026
Marc D. Reitter — Date of Execution

POWER OF ATTORNEY

PUBLIC SERVICE COMPANY of OKLAHOMA

Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 2025

The undersigned directors of PUBLIC SERVICE COMPANY of OKLAHOMA, an Oklahoma corporation (the "Company"), do hereby constitute and appoint WILLIAM J. FEHRMAN, TREVOR I. MIHALIK and MATTHEW D. FRANSEN, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2025, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned have signed these presents as of the “Date of Execution” set forth below.

/s/ Robert B. Berntsen — February 10, 2026
Robert B. Berntsen — Date of Execution

/s/ William J. Fehrman — February 10, 2026
William J. Fehrman — Date of Execution

/s/ Trevor I. Mihalik — February 10, 2026
Trevor I. Mihalik — Date of Execution

/s/ Leigh Anne Strahler — February 10, 2026 — Leigh Anne Strahler — Date of Execution

POWER OF ATTORNEY

SOUTHWESTERN ELECTRIC POWER COMPANY

Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 2025

The undersigned directors of SOUTHWESTERN ELECTRIC POWER COMPANY, a Delaware corporation (the "Company"), do hereby constitute and appoint WILLIAM J. FEHRMAN, TREVOR I. MIHALIK and MATTHEW D. FRANSEN, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2025, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned have signed these presents as of the “Date of Execution” set forth below.

/s/ Robert B. Berntsen — February 10, 2026
Robert B. Berntsen — Date of Execution

/s/ William J. Fehrman — February 10, 2026
William J. Fehrman — Date of Execution

/s/ D. Brett Mattison — February 10, 2026
D. Brett Mattison — Date of Execution

/s/ Trevor I. Mihalik — February 10, 2026
Trevor I. Mihalik — Date of Execution

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, William J. Fehrman, certify that:

1. I have reviewed this report on Form 10-K of American Electric Power Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By: /s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, William J. Fehrman, certify that:

1. I have reviewed this report on Form 10-K of AEP Transmission Company, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By: /s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, William J. Fehrman, certify that:

1. I have reviewed this report on Form 10-K of AEP Texas Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By: /s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, William J. Fehrman, certify that:

1. I have reviewed this report on Form 10-K of Appalachian Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By: /s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, William J. Fehrman, certify that:

1. I have reviewed this report on Form 10-K of Indiana Michigan Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By: /s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, William J. Fehrman, certify that:

1. I have reviewed this report on Form 10-K of Ohio Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By: /s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, William J. Fehrman, certify that:

1. I have reviewed this report on Form 10-K of Public Service Company of Oklahoma;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By: /s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, William J. Fehrman, certify that:

1. I have reviewed this report on Form 10-K of Southwestern Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By: /s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Trevor I. Mihalik, certify that:

1. I have reviewed this report on Form 10-K of American Electric Power Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By: /s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Trevor I. Mihalik, certify that:

1. I have reviewed this report on Form 10-K of AEP Transmission Company, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By:

/s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Trevor I. Mihalik, certify that:

1. I have reviewed this report on Form 10-K of AEP Texas Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By:

/s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Trevor I. Mihalik, certify that:

1. I have reviewed this report on Form 10-K of Appalachian Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By:

/s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Trevor I. Mihalik, certify that:

1. I have reviewed this report on Form 10-K of Indiana Michigan Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By:

/s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Trevor I. Mihalik, certify that:

1. I have reviewed this report on Form 10-K of Ohio Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By:

/s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Trevor I. Mihalik, certify that:

1. I have reviewed this report on Form 10-K of Public Service Company of Oklahoma;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By: /s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Trevor I. Mihalik, certify that:

1. I have reviewed this report on Form 10-K of Southwestern Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 12, 2026

By:

/s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of American Electric Power Company, Inc. (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, William J. Fehrman, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of AEP Transmission Company, LLC (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, William J. Fehrman, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to AEP Transmission Company, LLC and will be retained by AEP Transmission Company, LLC and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of AEP Texas Inc. (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, William J. Fehrman, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to AEP Texas Inc. and will be retained by AEP Texas Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Appalachian Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, William J. Fehrman, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to Appalachian Power Company and will be retained by Appalachian Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Indiana Michigan Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, William J. Fehrman, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to Indiana Michigan Power Company and will be retained by Indiana Michigan Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Ohio Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, William J. Fehrman, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to Ohio Power Company and will be retained by Ohio Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Public Service Company of Oklahoma (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, William J. Fehrman, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to Public Service Company of Oklahoma and will be retained by Public Service Company of Oklahoma and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Southwestern Electric Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, William J. Fehrman, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ William J. Fehrman
William J. Fehrman
Chief Executive Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to Southwestern Electric Power Company and will be retained by Southwestern Electric Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of American Electric Power Company, Inc. (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, Trevor I. Mihalik, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of AEP Transmission Company, LLC (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, Trevor I. Mihalik, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to AEP Transmission Company, LLC and will be retained by AEP Transmission Company, LLC and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of AEP Texas Inc. (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, Trevor I. Mihalik, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to AEP Texas Inc. and will be retained by AEP Texas Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Appalachian Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, Trevor I. Mihalik, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to Appalachian Power Company and will be retained by Appalachian Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Indiana Michigan Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, Trevor I. Mihalik, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to Indiana Michigan Power Company and will be retained by Indiana Michigan Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Ohio Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, Trevor I. Mihalik, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to Ohio Power Company and will be retained by Ohio Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Public Service Company of Oklahoma (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, Trevor I. Mihalik, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to Public Service Company of Oklahoma and will be retained by Public Service Company of Oklahoma and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Southwestern Electric Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof, I, Trevor I. Mihalik, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Trevor I. Mihalik
Trevor I. Mihalik
Chief Financial Officer

February 12, 2026

A signed original of this written statement required by Section 906 has been provided to Southwestern Electric Power Company and will be retained by Southwestern Electric Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

APPENDIX 7

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2025**

or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____to_____

Commission File Number	Exact name of registrant as specified in its charter, state of incorporation, address of principal executive offices and telephone number	I.R.S. Employer Identification Number
001-38515	**EVERGY, INC.** (a Missouri corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	82-2733395
001-03523	**EVERGY KANSAS CENTRAL, INC.** (a Kansas corporation) 818 South Kansas Avenue Topeka, Kansas 66612 (785) 575-6300	48-0290150
000-51873	**EVERGY METRO, INC.** (a Missouri corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	44-0308720

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Evergy, Inc. common stock	EVRG	The Nasdaq Stock Market LLC

Securities registered pursuant to Section 12(g) of the Act: Evergy Kansas Central, Inc. Common Stock $0.01 par value and Evergy Metro, Inc. Common Stock without par value.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Evergy, Inc.	Yes	☒	No	☐
Evergy Kansas Central, Inc.	Yes	☐	No	☒
Evergy Metro, Inc.	Yes	☐	No	☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Evergy, Inc.	Yes	☐	No	☒
Evergy Kansas Central, Inc.	Yes	☐	No	☒
Evergy Metro, Inc.	Yes	☐	No	☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Evergy, Inc.	Yes	☒	No	☐
Evergy Kansas Central, Inc.	Yes	☒	No	☐
Evergy Metro, Inc.	Yes	☒	No	☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Evergy, Inc.	Yes	☒	No	☐
Evergy Kansas Central, Inc.	Yes	☒	No	☐
Evergy Metro, Inc.	Yes	☒	No	☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Evergy, Inc.	Large Accelerated Filer	☒	Accelerated Filer	☐	Non-accelerated Filer	☐	Smaller Reporting Company	☐	Emerging Growth Company	☐
Evergy Kansas Central, Inc.	Large Accelerated Filer	☐	Accelerated Filer	☐	Non-accelerated Filer	☒	Smaller Reporting Company	☐	Emerging Growth Company	☐
Evergy Metro, Inc.	Large Accelerated Filer	☐	Accelerated Filer	☐	Non-accelerated Filer	☒	Smaller Reporting Company	☐	Emerging Growth Company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Evergy, Inc.	☐
Evergy Kansas Central, Inc.	☐
Evergy Metro, Inc.	☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

Evergy, Inc.	Yes	☒	No	☐
Evergy Kansas Central, Inc.	Yes	☐	No	☒
Evergy Metro, Inc.	Yes	☐	No	☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.

Evergy, Inc.	Yes	☐	No	☒
Evergy Kansas Central, Inc.	Yes	☐	No	☒

Evergy Metro, Inc.	Yes	☐	No	☒

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b).

Evergy, Inc.	Yes	☐	No	☒
Evergy Kansas Central, Inc.	Yes	☐	No	☒
Evergy Metro, Inc.	Yes	☐	No	☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Evergy, Inc.	Yes	☐	No	☒
Evergy Kansas Central, Inc.	Yes	☐	No	☒
Evergy Metro, Inc.	Yes	☐	No	☒

The aggregate market value of the voting and non-voting common equity held by non-affiliates of Evergy, Inc. (based on the closing price of its common stock on The Nasdaq Stock Market LLC on June 30, 2025) was approximately $15,667,375,144. All of the common equity of Evergy Kansas Central, Inc. and Evergy Metro, Inc. is held by Evergy, Inc.

On February 11, 2026, Evergy, Inc. had 230,281,586 shares of common stock outstanding.

On February 11, 2026, Evergy Kansas Central, Inc. and Evergy Metro, Inc. each had one share of common stock outstanding and held by Evergy, Inc.

Evergy Kansas Central, Inc. and Evergy Metro, Inc. meet the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format.

Documents Incorporated by Reference

Portions of the 2026 annual meeting proxy statement of Evergy, Inc. to be filed with the Securities and Exchange Commission are incorporated by reference in Part III of this report.

This combined annual report on Form 10-K is provided by the following registrants: Evergy, Inc. (Evergy), Evergy Kansas Central, Inc. (Evergy Kansas Central) and Evergy Metro, Inc. (Evergy Metro) (collectively, the Evergy Companies). Information relating to any individual registrant is filed by such registrant solely on its own behalf. Each registrant makes no representation as to information relating exclusively to the other registrants.

TABLE OF CONTENTS

		Page Number
	Cautionary Statements Regarding Certain Forward-Looking Information	3
	Glossary of Terms	5
	PART I	
Item 1.	Business	8
Item 1A.	Risk Factors	17
Item 1B.	Unresolved Staff Comments	30
Item 1C.	Cybersecurity	30
Item 2.	Properties	33
Item 3.	Legal Proceedings	36
Item 4.	Mine Safety Disclosures	36
	PART II	
Item 5.	Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	37
Item 6.	Reserved	37
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	37
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	63
Item 8.	Financial Statements and Supplementary Data	66
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	165
Item 9A.	Controls and Procedures	165
Item 9B.	Other Information	169
Item 9C.	Disclosure Regarding Foreign Jurisdictions that Prevent Inspections	169
	PART III	
Item 10.	Directors, Executive Officers and Corporate Governance	169
Item 11.	Executive Compensation	170
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	170
Item 13.	Certain Relationships and Related Transactions, and Director Independence	171
Item 14.	Principal Accounting Fees and Services	171
	PART IV	
Item 15.	Exhibits and Financial Statement Schedules	173
	Signatures	196

CAUTIONARY STATEMENTS REGARDING CERTAIN FORWARD-LOOKING INFORMATION

Statements made in this document that are not based on historical facts are forward-looking, may involve risks and uncertainties, and are intended to be as of the date when made. Forward-looking statements include, but are not limited to, statements relating to Evergy's strategic plan, including, without limitation, those related to earnings per share, dividend, operating and maintenance expense and capital investment goals; the outcome of legislative efforts and regulatory and legal proceedings; future energy demand, including demand driven by new and existing customers; future power prices; plans with respect to existing and potential future generation resources; the availability and cost of generation resources and energy storage; target emissions reductions; and other matters relating to expected financial performance or affecting future operations. Forward-looking statements are often accompanied by forward-looking words such as "anticipates," "believes," "expects," "estimates," "forecasts," "guidance," "should," "could," "may," "seeks," "intends," "predict," "potential," "opportunities," "proposed," "projects," "planned," "target," "budget," "outlook," "remain confident," "goal," "will" or other words of similar meaning. Forward-looking statements involve risks, uncertainties and other factors that could cause actual results to differ materially from the forward-looking information.

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, the Evergy Companies are providing a number of risks, uncertainties and other factors that could cause actual results to differ from the forward-looking information. These risks, uncertainties and other factors include, but are not limited to: economic and weather conditions and any impact on sales, prices and costs; significant changes in the demand for electricity, including demand from data centers and other large load customers; changes in business strategy or operations, including with respect to the Evergy Companies' strategy to meet demand requirements of existing and future customers; uncertainties related to projected rapid growth in electricity demand driven primarily by data centers and other large load customers and the related requirement for new generation and transmission investments, creating capital access, revenue recovery and customer affordability risks; the impact of federal, state and local political, legislative, judicial and regulatory actions or developments, including deregulation, re-regulation, securitization and restructuring of the electric utility industry; prolonged or recurring U.S. federal government shutdowns; changes in U.S. trade policies (including tariffs and other trade measures) and responses from other countries; the ability to build or acquire generation, battery storage and transmission facilities to meet the future demand for electricity from customers; the ability to control costs, avoid costs and schedule overruns during the development, construction and operation of generation, battery storage, transmission, distribution or other projects due to challenges, which include, but are not limited to, changes in labor costs, availability and productivity, challenges with the management of contractors or vendors, subcontractor performance, shortages, delays, increased costs or inconsistent quality of equipment, materials and labor and increased financing costs as a result of changes in interest rates or as a result of project delays; decisions of regulators regarding, among other things, customer rates and the prudency of operational decisions such as capital expenditures and asset retirements; changes in applicable laws, regulations, rules, principles or practices, or the interpretations thereof, governing tax, accounting and environmental matters, including air and water quality and waste management and disposal; development, adoption and use of artificial intelligence by the Evergy Companies and its third-party vendors; the impact of climate change, including increased frequency and severity of significant weather events; risks relating to potential wildfires, including costs of litigation, potential regulatory penalties and damages in excess of insurance liability coverage; the extent to which counterparties are willing to do business with, finance the operations of or purchase energy from the Evergy Companies due to the fact that the Evergy Companies operate coal-fired generation; prices and availability of electricity and natural gas in wholesale markets; market perception of the energy industry and the Evergy Companies; the impact of future pandemic health events on, among other things, sales, results of operations, financial position, liquidity and cash flows, and also on operational issues, such as supply chain issues and the availability and ability of the Evergy Companies' employees and suppliers to perform the functions that are necessary to operate the Evergy Companies; changes in the energy trading markets in which the Evergy Companies participate, including retroactive repricing of transactions by regional transmission organizations (RTO) and independent system operators; financial market conditions and performance, disruptions in the banking industry, including volatility in interest rates and credit spreads and in availability and cost of capital and the effects on derivatives and hedges and ability to obtain capital to finance large construction projects, nuclear decommissioning trust and pension plan assets and costs; impairments of long-lived assets or goodwill; credit ratings; inflation rates; effectiveness of risk management policies and procedures and the ability of counterparties to satisfy their

contractual commitments including new large data center customers; impact of physical and cybersecurity breaches, criminal activity, terrorist attacks, acts of war and other disruptions to the Evergy Companies' facilities or information technology infrastructure or the facilities and infrastructure of third-party service providers on which the Evergy Companies rely; impact of geopolitical conflicts on the global energy market, including the ability to contract for non-Russian sourced uranium; ability to carry out marketing and sales plans; cost, availability, quality and timely provision of equipment, supplies, labor and fuel; ability to achieve generation goals and the occurrence and duration of planned and unplanned generation outages; the Evergy Companies' ability to manage their generation, transmission and distribution development plans and transmission joint ventures; the inherent risks associated with the ownership and operation of a nuclear facility, including environmental, health, safety, regulatory and financial risks; workforce risks, including those related to the Evergy Companies' ability to attract and retain qualified personnel, maintain satisfactory relationships with their labor unions and manage costs of, or changes in, wages, retirement, health care and other benefits; disruption, costs and uncertainties caused by or related to the actions of individuals or entities, such as activist shareholders or special interest groups, that seek to influence Evergy's strategic plan, financial results or operations; the impact of changing expectations and demands of the Evergy Companies' customers, regulators, investors and stakeholders, including differing views on environmental, social and governance concerns; the possibility that strategic initiatives, including mergers, acquisitions, joint ventures and divestitures, and long-term financial plans, may not create the value that they are expected to achieve in a timely manner or at all; difficulties in maintaining relationships with customers, employees, contractors, regulators or suppliers; the outcome of litigation involving the Evergy Companies; and other risks and uncertainties.

This list of factors is not all-inclusive because it is not possible to predict all factors. You should also carefully consider the information contained in the Evergy Companies' other filings with the Securities and Exchange Commission (SEC). Additional risks and uncertainties are discussed from time to time in current, quarterly and annual reports filed by the Evergy Companies with the SEC. New factors emerge from time to time, and it's not possible for the Evergy Companies to predict all such factors, nor can the Evergy Companies assess the impact of each such factor on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained or implied in any forward-looking statement. Given these uncertainties, undue reliance should not be placed on these forward-looking statements. The Evergy Companies undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by law.

AVAILABLE INFORMATION

The SEC maintains an internet site that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC at sec.gov. Additionally, information about the Evergy Companies, including their combined annual reports on Form 10-K, combined quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with the SEC, is also available through the Evergy Companies' website, http://investors.evergy.com. Such reports are accessible at no charge and are made available as soon as reasonably practical after such material is filed with or furnished to the SEC.

Investors should note that the Evergy Companies announce material financial information in SEC filings, press releases and public conference calls. In accordance with SEC guidelines, the Evergy Companies also use the Investor Relations section of their website, http://investors.evergy.com, to communicate with investors. It is possible that the financial and other information posted there could be deemed to be material information. The information on the Evergy Companies' website is not part of this document.

GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations or acronyms that are found throughout this report.

Abbreviation or Acronym	Definition
AAO	Accounting authority order
ACE	Affordable Clean Energy
AEP	American Electric Power Company, Inc.
AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive income
AROs	Asset retirement obligations
ASC	Accounting Standards Codification
ATM Program	At-the-Market Program
ATRR	Annual Transmission Revenue Requirement
BSER	Best system of emission reduction
CAA	Clean Air Act
CARFR	Credit-adjusted risk-free rates
CCGT	Combined cycle gas turbine
CCN	Certificate of Convenience and Necessity
CCRs	Coal combustion residuals
CCS	Carbon capture and sequestration
CNO	Chief Nuclear Officer
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COLI	Corporate-owned life insurance
Crossroads	Crossroads Energy Center
CSAPR	Cross-State Air Pollution Rule
CT	Combustion turbine
CTO	Chief Technology Officer
CWIP	Construction work in progress
Dogwood	Dogwood Energy Center
EIRR	Environmental Improvement Revenue Refunding
EPA	Environmental Protection Agency
EPS	Earnings per common share
ERISA	Employee Retirement Income Security Act of 1974, as amended
ESA	Electric service agreement
ESG	Environmental, social and governance
Evergy	Evergy, Inc. and its consolidated subsidiaries
Evergy Board	Evergy Board of Directors
Evergy Companies	Evergy, Evergy Kansas Central, and Evergy Metro, collectively, which are individual registrants within the Evergy consolidated group
Evergy Kansas Central	Evergy Kansas Central, Inc., a wholly-owned subsidiary of Evergy, and its consolidated subsidiaries
Evergy Kansas Central Mortgage Indenture	Evergy Kansas Central Mortgage Indenture and Deed of Trust dated as of July 1, 1939, as amended and supplemented
Evergy Kansas South	Evergy Kansas South, Inc., a wholly-owned subsidiary of Evergy Kansas Central

Abbreviation or Acronym	Definition
Evergy Kansas South Mortgage Indenture	Evergy Kansas South Mortgage Indenture and Deed of Trust dated as of April 1, 1940, as amended and supplemented
Evergy Metro	Evergy Metro, Inc., a wholly-owned subsidiary of Evergy, and its consolidated subsidiaries
Evergy Metro Mortgage Indenture	Evergy Metro General Mortgage Indenture and Deed of Trust dated as of December 1, 1986, as amended and supplemented
Evergy Missouri West	Evergy Missouri West, Inc., a wholly-owned subsidiary of Evergy
Evergy Missouri West Mortgage Indenture	Evergy Missouri West First Mortgage Indenture and Deed of Trust, dated as of March 1, 2022, as supplemented
Evergy Missouri West Storm Funding	Evergy Missouri West Storm Funding I, LLC
Evergy Transmission Company	Evergy Transmission Company, LLC
Exchange Act	The Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FER	Facility Evaluation Report
FERC	Federal Energy Regulatory Commission
FIP	Federal implementation plan
FMBs	First Mortgage Bonds
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse gas
Great Plains Energy	Great Plains Energy Incorporated
IBEW	International Brotherhood of Electrical Workers
IRA	Inflation Reduction Act
HB	House Bill
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ITFIP	Interstate Transport Federal Implementation Plans
ITSIP	Interstate Transport State Implementation Plans
JEC	Jeffrey Energy Center
KCC	State Corporation Commission of the State of Kansas
KDHE	Kansas Department of Health & Environment
KEEIA	Kansas Energy Efficiency Investment Act
kV	Kilovolt
kWh	Kilowatt hour
LEC	Lawrence Energy Center
LLPS	Large Load Power Service
MDNR	Missouri Department of Natural Resources
MEEIA	Missouri Energy Efficiency Investment Act
MPSC	Public Service Commission of the State of Missouri
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
NAV	Net asset value
NERC	North American Electric Reliability Corporation
NIST CSF	National Institute of Standards and Technology Cybersecurity Framework
NIST RMF	National Institute of Standards and Technology Risk Management Framework
NOL	Net operating loss

Abbreviation or Acronym	Definition
NRC	Nuclear Regulatory Commission
OBBBA	One Big Beautiful Bill Act
OCI	Other comprehensive income
PISA	Plant-in-service accounting
Prairie Wind	Prairie Wind Transmission, LLC, 50% owned by Evergy Kansas Central
PRB	Powder River Basin
PTC	Production tax credit
RSU	Restricted share unit
RTO	Regional transmission organization
Scope 1	Direct greenhouse gas emissions that occur from sources that are controlled or owned by an organization
Scope 2	Indirect greenhouse gas emissions associated with the purchase of electricity, steam, heat or cooling
SB	Senate Bill
SCGT	Simple cycle gas turbine
SEC	Securities and Exchange Commission
Securitized Bonds	Securitized Utility Tariff Bonds
SIP	State implementation plan
SPP	Southwest Power Pool, Inc.
TCR	Transmission congestion rights
TDC	Transmission delivery charge
TFR	Transmission formula rate
Transource	Transource Energy, LLC and its subsidiaries, 13.5% owned by Evergy Transmission Company
UGSOA	United Government Security Officers of America
VaR	Value at Risk
VIE	Variable interest entity
WACC	Weighted average cost of capital
Wolf Creek	Wolf Creek Generating Station

PART I

ITEM 1. BUSINESS

General

Evergy, Inc., Evergy Kansas Central, Inc. and Evergy Metro, Inc. are separate registrants filing this combined annual report on Form 10-K. The terms "Evergy," "Evergy Kansas Central," "Evergy Metro" and "Evergy Companies" are used throughout this report. "Evergy" refers to Evergy, Inc. and its consolidated subsidiaries, unless otherwise indicated. "Evergy Kansas Central" refers to Evergy Kansas Central, Inc. and its consolidated subsidiaries, unless otherwise indicated. "Evergy Metro" refers to Evergy Metro, Inc. and its consolidated subsidiaries, unless otherwise indicated. "Evergy Companies" refers to Evergy, Evergy Kansas Central, and Evergy Metro, collectively, which are individual registrants within the Evergy consolidated group.

Information in other Items of this report as to which reference is made in this Item 1 is hereby incorporated by reference in this Item 1. The use of terms such as "see" or "refer to" shall be deemed to incorporate into this Item 1 the information to which such reference is made.

EVERGY, INC.

Evergy is a public utility holding company incorporated in 2017 and headquartered in Kansas City, Missouri. Evergy operates primarily through the following wholly-owned direct subsidiaries listed below.

- Evergy Kansas Central, Inc. (Evergy Kansas Central) is an integrated, regulated electric utility that provides electricity to customers in the state of Kansas. Evergy Kansas Central has one active wholly-owned subsidiary with significant operations, Evergy Kansas South, Inc. (Evergy Kansas South).
- Evergy Metro, Inc. (Evergy Metro) is an integrated, regulated electric utility that provides electricity to customers in the states of Missouri and Kansas.
- Evergy Missouri West, Inc. (Evergy Missouri West) is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri.
- Evergy Transmission Company, LLC (Evergy Transmission Company) owns 13.5% of Transource Energy, LLC (Transource) with the remaining 86.5% owned by AEP Transmission Holding Company, LLC, a subsidiary of American Electric Power Company, Inc. (AEP). Transource is focused on the development of competitive electric transmission projects. Evergy Transmission Company accounts for its investment in Transource under the equity method.

Evergy Kansas Central also owns a 50% interest in Prairie Wind Transmission, LLC (Prairie Wind), which is a joint venture between Evergy Kansas Central and subsidiaries of AEP and Berkshire Hathaway Energy Company. Prairie Wind owns a 108-mile, 345 kilovolt (kV) double-circuit transmission line that provides transmission service in the Southwest Power Pool, Inc. (SPP). Evergy Kansas Central accounts for its investment in Prairie Wind under the equity method.

Evergy Kansas Central, Evergy Kansas South, Evergy Metro, and Evergy Missouri West conduct business in their respective service territories using the name Evergy. The Evergy Companies assess financial performance and allocate resources on a consolidated basis (i.e., operate in one segment). Evergy serves approximately 1.7 million customers located in Kansas and Missouri. Customers include approximately 1.5 million residences, 0.2 million commercial firms and 7,400 industrials, municipalities and other electric utilities. Evergy is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter.

Evergy expects to continue operating its integrated utilities within the currently existing regulatory frameworks and is focused on enabling economic development across all of its service territories to strengthen the communities it serves and meet existing and future customer electricity demand growth through the continued evolution of its generation, transmission and distribution systems. Evergy will remain focused on consistently delivering on its affordability, reliability and sustainability objectives and delivering competitive long-term returns to shareholders,

including growth in earnings per share and targeting a 50%-60% dividend payout ratio. The core tenets of Evergy's strategy are as follows:

- Affordability – maintaining affordable rates while investing in infrastructure and technology to support growth and prosperity;
- Reliability – targeting top-tier performance in reliability, customer service and generation; and
- Sustainability – advancing an "all-of-the-above" generation portfolio.

See Item 7, Management's Discussion and Analysis of Financial Operations (MD&A) – Executive Summary – Strategy, for additional information.

The table below summarizes the percentage of Evergy's revenues by customer class.

	2025	2024	2023
Residential	37%	37%	37%
Commercial	33%	34%	33%
Industrial	11%	12%	12%
Wholesale	5%	5%	7%
Transmission	9%	8%	7%
Other	5%	4%	4%
Total	100%	100%	100%

The table below summarizes the percentage of Evergy's retail electricity sales volumes by customer class.

	2025	2024	2023
Residential	37%	37%	37%
Commercial	44%	43%	43%
Industrial	19%	20%	20%
Total	100%	100%	100%

Regulation

Evergy Kansas Central and Evergy Metro's Kansas operations are regulated by the State Corporation Commission of the State of Kansas (KCC) and Evergy Metro's Missouri operations and Evergy Missouri West are regulated by the Public Service Commission of the State of Missouri (MPSC), in each case with respect to retail rates, certain accounting matters, standards of service and, in certain cases, the issuance of securities, certification of facilities and service territories. The Evergy Companies are also subject to regulation by the Federal Energy Regulatory Commission (FERC) with respect to transmission, wholesale sales and rates, the issuance of securities in certain cases and other matters. Evergy has an indirect 94% ownership interest in Wolf Creek Generating Station (Wolf Creek), which is subject to regulation by the Nuclear Regulatory Commission (NRC) with respect to licensing, operations and safety-related requirements.

The table below summarizes the rate orders in effect for Evergy Kansas Central's, Evergy Metro's and Evergy Missouri West's retail rate jurisdictions.

	Regulator	Allowed Return on Equity	Effective Date
Evergy Kansas Central[(a)]	KCC	9.7% (b)	October 2025
Evergy Metro - Kansas	KCC	9.4% (b)	December 2023
Evergy Metro - Missouri	MPSC	(c)	January 2023
Evergy Missouri West	MPSC	(c)	January 2025

[(a)] The KCC establishes rates for Evergy Kansas Central and Evergy Kansas South on a consolidated basis.

[b] Current KCC rate orders do not contain an explicit allowed return on equity. The return on equity presented in this table reflects the current order in Kansas which stated an allowed return on equity to be utilized for purposes of the transmission delivery charge (TDC).
[c] Current MPSC rate orders do not contain an explicit allowed return on equity.

Evergy expects its 2026 Kansas and Missouri jurisdictional retail revenues to be approximately 60% and 40%, respectively, based on historical averages of Evergy Kansas Central's, Evergy Metro's and Evergy Missouri West's total retail revenues.

See Item 7, MD&A, Critical Accounting Policies section, and Note 4 to the consolidated financial statements for additional information concerning regulatory matters.

Competition
Missouri and Kansas continue to operate on the fully integrated and regulated retail utility model. As a result, the Evergy Companies do not compete with others to supply and deliver electricity in their franchised service territories in exchange for agreeing to have their terms of service regulated by state regulatory bodies. If Missouri or Kansas were to pass and implement legislation authorizing or mandating retail choice, Evergy may no longer be able to apply regulated utility accounting principles to deregulated portions of its operations, which may require a surcharge to recover certain costs from legacy customers or could lead to a write-off of certain regulatory assets and liabilities.

Evergy competes in the wholesale market to sell power in circumstances when the power it generates is not required for retail customers in its service territory. This competition primarily occurs within the SPP Integrated Marketplace, in which Evergy Kansas Central, Evergy Metro and Evergy Missouri West are participants. This marketplace determines which generating units among market participants should run, within the operating constraints of a unit, at any given time for maximum regional cost-effectiveness.

The SPP Integrated Marketplace is similar to other regional transmission organization (RTO) or Independent System Operator (ISO) markets currently operating in other regions of the United States.

Power Supply
Evergy has approximately 15,800 megawatts (MWs) of owned generating capacity and renewable power purchase agreements. Evergy's owned generation and power purchases from others, as a percentage of total megawatt hours (MWhs) generated and purchased, was approximately 60% and 40%, respectively, over the last three years. About 60% of Evergy's purchased power was purchased under long-term renewable purchased power contracts over the last three years. Evergy purchases power to meet its customers' needs, to satisfy firm power commitments or to meet renewable energy standards. Management believes Evergy will be able to meet its future power purchase needs due to the coordination of planning and operations in the SPP region and existing power purchase agreements; however, price and availability of power purchases may be impacted during periods of high demand or reduced supply.

Evergy's total capacity by fuel type, including both owned generating capacity and power purchase agreements, is detailed in the table below.

Fuel Type	Estimated 2026 MW Capacity	Percent of Total Capacity
Coal	5,930	37 %
Wind[a]	4,525	29
Natural gas and oil	4,229	27
Uranium	1,106	7
Solar and landfill gas	22	—
Total capacity	15,812	100 %

[a] MWs are based on nameplate capacity of the wind facility. Includes owned generating capacity of 778 MWs and long-term power purchase agreements of approximately 3,747 MWs of wind generation that expire from 2028 through 2048. See Item 2, Properties, for additional information.

Evergy has also entered into multiple firm capacity agreements with effective dates beginning between 2025 and 2028 to help it meet its projected load capacity requirements. These agreements total approximately 600 MWs and contain various expiration dates ranging between 2029 and 2033.

Evergy's projected peak summer demand for 2026 is approximately 11,200 MWs. Evergy expects to meet its projected capacity requirements for 2026 with its existing generation assets and power purchases. See "Modernizing and Expanding Evergy's Generation Fleet" below for further information regarding Evergy's long-term strategy with regard to its generating assets and power purchases.

Evergy Kansas Central, Evergy Metro and Evergy Missouri West are members of the SPP. The SPP is a FERC-approved RTO with the responsibility to ensure reliable power supply, adequate transmission infrastructure and competitive wholesale electricity prices in the region. As SPP members, Evergy Kansas Central, Evergy Metro and Evergy Missouri West were required to maintain a minimum reserve margin of 15% for 2025. Beginning in 2026, Evergy Kansas Central, Evergy Metro and Evergy Missouri West will be required to maintain a minimum reserve margin of 16%. This net positive supply of capacity is maintained through generation asset ownership, capacity agreements, power purchase agreements and peak demand reduction programs. The reserve margin is designed to support reliability of the region's electric supply.

Environmental Matters

The Evergy Companies are subject to extensive and evolving federal, state and local environmental laws, regulations and permit requirements relating to air and water quality, waste management and hazardous substance disposal, protected natural resources (such as wetlands, federally-listed species and other protected wildlife) and health and safety. For example, Evergy Kansas Central, Evergy Metro and Evergy Missouri West combust large amounts of fossil fuels in the production of electricity, which results in significant emissions of carbon dioxide (CO_2) and other greenhouse gases (GHG). Federal legislation regulates the emission of GHGs and numerous states and regions have adopted programs to stabilize or reduce GHG emissions. The Environmental Protection Agency (EPA), the Kansas Department of Health and Environment (KDHE) and the Missouri Department of Natural Resources (MDNR) regulate emissions under the Clean Air Act (CAA), water under the Clean Water Act and waste management under the Resource Conservation and Recovery Act, among other laws and regulations. See Note 15 to the consolidated financial statements for additional information. There have been, and management believes there will continue to be, policy, legal and regulatory efforts to influence climate change, such as efforts to reduce GHG emissions, impose a tax on those emissions and create incentives for low-carbon generation and energy efficiency. These efforts, and climate change itself, have the potential to adversely affect the Evergy Companies' operations, financial position and cash flows. See Part I, Item 1A, Risk Factors, for additional information.

The Evergy Companies have taken, and will continue to take, proactive measures to mitigate the impact of climate change on its businesses. For example, the Evergy Companies regularly conduct preparedness exercises for a variety of disruptive events, including storms, which may become more frequent or intense due to climate change. In addition, the Evergy Companies have invested, and will continue to invest, in grid resiliency. Much of the Evergy Companies' infrastructure is advanced in age, and grid resiliency efforts include building additional transmission and distribution lines, performing necessary system maintenance, replacing necessary infrastructure and proactively managing the vegetation that can damage systems during severe weather. The Evergy Companies also monitor water conditions at their generating facilities and focus on water conservation at these facilities to address resource depletion.

Modernizing and Expanding Evergy's Generation Fleet

Evergy is committed to a long-term strategy focused on affordability, reliability and sustainability, including fostering economic development in Kansas and Missouri by supporting the attraction of new businesses and large load customers while ensuring protections for existing customers through key safeguards included in the Large Load Power Service (LLPS) rate plans.

Evergy’s generation portfolio balances various fuel types which have historically provided cost and reliability benefits. For example, because renewable generation can be intermittent, a portfolio with dispatchable baseload generation that relies on varying fuel types, including a mix of uranium, coal and natural gas, has helped to maintain

a consistent availability of power. In addition, the Evergy Companies must prudently utilize the generation assets that regulators have allowed the Evergy Companies to include in rates. The Evergy Companies use an integrated resource plan (IRP), a detailed analysis that estimates factors that influence the future supply and demand for electricity, to inform the manner in which they supply electricity. The IRP considers forecasts of future electricity demand, fuel prices, transmission improvements, new generating capacity, cost of environmental compliance, integration of renewables, energy storage, energy efficiency and demand response initiatives, among other factors. The modernization of Evergy's generation fleet over time is expected to result in ongoing reductions in emissions. Strategies that the Evergy Companies are pursuing to modernize and expand the generation fleet include:

- developing natural gas and renewable energy facilities;
- exploring opportunities to add battery energy storage systems and nuclear generation;
- grid investment and advancement;
- collaborating with regulators to offer customers the opportunity to procure electricity produced with renewable resources; and
- investing in customer energy efficiency programs.

Since 2005, the Evergy Companies have added over 4,500 MWs of renewable generation capacity, while retiring more than 2,400 MWs of fossil generation. The fleet modernization steps outlined above will allow Evergy to support economic expansion in Kansas and Missouri and, as reflected in Evergy's IRPs, are expected in the future to be accompanied by the retirement of older coal-fired generation units and/or the conversion of coal-fired generation resources to natural gas.

This generation modernization is expected to have a corresponding impact on CO_2 emissions, continuing a long-term downward trend. In 2025, Evergy's total CO_2 emissions from owned generation units were nearly 50% lower than 2005 levels. Through the ongoing modernization of its generation fleet, Evergy has a long-term goal to achieve net-zero carbon dioxide equivalent (CO_2e) emissions, for scope 1 and scope 2 emissions, by 2050, a time frame that is consistent with the majority of industry peers with stated net-zero emissions goals. The trajectory and timing of achieving Evergy's long-term emissions reduction goal is expected to be dependent on the evolution of Evergy's IRPs and many external factors, including enabling technology developments, trends in total demand for electricity, the reliability of the power grid, availability of transmission capacity and supportive energy policies and regulations, among other external factors. See "Cautionary Statements Regarding Certain Forward-Looking Information" and Part I, Item 1A. Risk Factors, for additional information.

See Item 2, Properties, for additional information regarding the Evergy Companies' renewable generation resources. The Evergy Companies are also committed to transparency. On its website, http://investors.evergy.com, Evergy provides quantitative and qualitative data regarding various environmental, social and governance matters, including information related to emissions, waste and water. The contents of the website, including reports and documents contained therein, are not incorporated into this filing.

See Note 15 to the consolidated financial statements for information regarding environmental matters.

Fuel

The fuel sources for Evergy's owned generation and power purchase agreements are coal, wind and other renewable sources, uranium and natural gas and oil. The actual 2025 fuel mix and fuel cost in cents per net kilowatt hour (kWh) delivered are outlined in the following table.

	Fuel Mix[a]	Fuel cost in cents per net kWh delivered
Fuel	Actual 2025	Actual 2025
Coal	47 %	2.27¢
Wind, landfill gas and solar[b]	28	1.83
Uranium	18	0.64
Natural gas and oil	7	4.47
Total	100 %	2.02

[a] Fuel mix based on percent of net MWhs generated by owned resources and delivered under renewable power purchase agreements.
[b] Fuel cost in cents per net kWh delivered includes costs associated with renewable power purchase agreements.

Coal

During 2026, Evergy's generating units, including jointly-owned units, are projected to use approximately 16 million tons of coal. Evergy Kansas Central, Evergy Metro and Evergy Missouri West have entered into coal-purchase contracts with various suppliers in Wyoming's Powder River Basin (PRB), the nation's principal supply region of low-sulfur coal, and with local suppliers. The coal to be provided under these contracts is expected to satisfy approximately 75%, 55% and 40% of the projected coal requirements for 2026, 2027 and 2028, respectively. The remainder of the coal requirements is expected to be fulfilled through entering into additional contracts or spot market purchases.

Evergy Kansas Central, Evergy Metro and Evergy Missouri West have also entered into rail transportation contracts with various railroads to transport coal from the PRB and local suppliers to their generating units. The transportation services to be provided under these contracts are expected to satisfy 70%, 25% and 25% of the projected transportation requirements for 2026, 2027 and 2028, respectively. The contract rates adjust for changes in railroad costs.

Nuclear Fuel

Evergy Kansas South and Evergy Metro each own 47% of Wolf Creek, which is Evergy's only nuclear generating unit. Wolf Creek purchases uranium and has it processed for use as fuel in its reactor. This process involves conversion of uranium concentrates to uranium hexafluoride, enrichment of uranium hexafluoride and fabrication of nuclear fuel assemblies. The owners of Wolf Creek have on hand or under contract all the uranium, uranium enrichment and conversion services needed to operate Wolf Creek through 2030. The owners also have under contract all the nuclear fuel assembly fabrication services required to operate Wolf Creek through 2045.

Natural Gas

Evergy purchases natural gas for use in its generating units primarily through spot market purchases. From time to time, Evergy also may enter into contracts, including the use of derivatives, in an effort to manage the cost of natural gas. For additional information about Evergy's exposure to commodity price risks, see Item 7A., Quantitative and Qualitative Disclosures About Market Risk.

Evergy Kansas Central, Evergy Metro and Evergy Missouri West maintain various natural gas transportation arrangements. These agreements expire based on the generating unit being served with expiration dates from 2026 to 2031.

Customer Energy Efficiency Programs
The Evergy Companies have implemented, and continue to offer, energy efficiency programs to help customers with their energy efficiency needs and to help manage energy costs. Both Missouri and Kansas have passed legislation promoting the implementation of cost-effective demand-side management programs and allowing for the recovery of these program costs from customers, along with the potential to earn performance incentives based upon certain criteria.

In Missouri, Evergy Metro and Evergy Missouri West currently offer a suite of energy efficiency programs for customers under the Missouri Energy Efficiency Investment Act (MEEIA). The MPSC has approved a portfolio of MEEIA programs that run through 2027. The MEEIA programs provide for the recovery of program costs, throughput disincentive and the opportunity to earn an incentive based upon certain program costs or demand savings achieved. The costs of the programs are recovered from customers through a rider mechanism.

In Kansas, Evergy Kansas Central and Evergy Metro currently offer a suite of energy efficiency programs for customers under the Kansas Energy Efficiency Investment Act (KEEIA). The KCC has approved a portfolio of KEEIA programs that run through February 2028. The KEEIA programs provide for the recovery of program costs, throughput disincentive and the opportunity to earn a performance incentive based primarily upon demand and energy savings achieved. The costs of the programs are recovered through a rider mechanism.

Human Capital Resources
As of December 31, 2025, the Evergy Companies had 4,691 employees, including 2,479 represented by five local unions of the International Brotherhood of Electrical Workers (IBEW) and one local union of the United Government Security Officers of America (UGSOA). The Evergy Companies' labor agreements expire at varying times from 2026 through 2028. The Evergy Companies employ 1,882 generation employees, 1,468 transmission and distribution employees and 1,341 support employees that work primarily in the states of Kansas and Missouri.

Evergy's mission is to empower a better future and a key component of this mission is maintaining a culture that emphasizes safety, integrity, ownership and adaptability.

Safety is a crucial part of Evergy's values. The components of Evergy's safety program include a strong management commitment to a safety-conscious work environment, hazard recognition and control, worksite analysis, contractor safety management and training. Evergy also conducts regular safety audits and assessments.

Evergy offers a competitive package of compensation and benefits to attract and retain talented employees, including market-competitive pay, healthcare and retirement benefits, paid time off, family leave and tuition reimbursement. Evergy also encourages employees to participate in a comprehensive well-being program that includes health and wellness-related activities and incentives, employee resource groups, gym membership reimbursement, paid volunteer hours, charitable donation match and free access to an employee assistance program.

Information About Evergy's Executive Officers

Set forth below is information relating to the executive officers of Evergy, Inc. Each executive officer holds the same position with each of Evergy Kansas Central, Inc., Evergy Metro, Inc., Evergy Kansas South, Inc. and Evergy Missouri West, Inc. as the executive officer holds with Evergy, Inc. Executive officers serve at the pleasure of Evergy's Board of Directors (Evergy Board). There are no family relationships among any of the executive officers, nor any arrangements or understandings between any executive officer and other persons pursuant to which he or she was appointed as an executive officer.

Name	Age	Current Position(s)	Year First Assumed an Officer Position
David A. Campbell [(a)]	57	Chairman, President and Chief Executive Officer	2021
W. Bryan Buckler [(b)]	53	Executive Vice President and Chief Financial Officer	2024
Charles A. Caisley [(c)]	52	Executive Vice President, Utility Operations and Chief Customer Officer	2011
John T. Bridson [(d)]	56	Senior Vice President, Generation and Operations Support	2025
Lesley L. Elwell [(e)]	55	Senior Vice President, Chief People Officer	2021
Heather A. Humphrey [(f)]	55	Senior Vice President, General Counsel and Corporate Secretary	2010
Charles L. King [(g)]	61	Senior Vice President and Chief Technology Officer	2013
Cleveland O. Reasoner [(h)]	60	Senior Vice President and Chief Nuclear Officer	2025
Matthew B. Gummig [(i)]	40	Vice President and Chief Accounting Officer	2025

(a) Mr. Campbell was appointed Chairman, President and Chief Executive Officer of Evergy, Inc. in May 2024. Mr. Campbell previously served as President and Chief Executive Officer of Evergy, Inc. (2021-2024), Executive Vice President and Chief Financial Officer of Vistra Energy Corp. (2019-2020), as President and Chief Executive Officer of InfraREIT, Inc. and President of Hunt Utility Services (2014-2019) and as President and Chief Executive Officer of Sharyland Utilities, LLC (2016-2019), and in various roles with TXU Corp. and its affiliated entities (2004-2013).

(b) Mr. Buckler was appointed Executive Vice President and Chief Financial Officer of Evergy, Inc. in October 2024. Mr. Buckler previously served as Chief Financial Officer of OGE Energy Corp. (2021-2024). Mr. Buckler also served as Vice President of Investor Relations at Duke Energy Corp. (2019-2020) and as Director of Financial Planning and Analysis at Duke Energy Corp. (2019).

(c) Mr. Caisley was appointed Executive Vice President, Utility Operations and Chief Customer Officer of Evergy, Inc. effective October 2025. Mr. Caisley previously served as Executive Vice President, Public Affairs and Chief Customer Officer of Evergy, Inc. (2024-2025) and as Senior Vice President, Public Affairs and Chief Customer Officer of Evergy, Inc. (2021-2024). He previously served as Senior Vice President, Marketing and Public Affairs and Chief Customer Officer of Evergy, Inc. (2018-2021). Mr. Caisley served as Vice President - Marketing and Public Affairs of Great Plains Energy Incorporated (Great Plains Energy), Evergy Metro and Evergy Missouri West (2011-2018). He was Senior Director of Public Affairs (2008-2011) and Director of Governmental Affairs of Evergy Metro (2007-2008).

(d) Mr. Bridson was appointed Senior Vice President, Generation and Operations Support of Evergy, Inc., effective October 2025. Mr. Bridson previously served as Vice President, Generation of Evergy, Inc. (2019-2025). He previously served as Senior Vice President, Generation and Marketing of Evergy Kansas Central (2015-2018). He joined Evergy Kansas Central in 1993 and held several positions with the company, including Vice President of Generation, Executive Director of Generation, Executive Director of Lawrence Energy Center, Executive Director of Gas-fired Power Plants, Director of Operations and Plant Engineer at Jeffrey Energy Center.

(e) Ms. Elwell currently serves as Senior Vice President, Chief People Officer of Evergy, Inc. Ms. Elwell previously served as Senior Vice President and Chief Human Resources Officer of Evergy, Inc. (2021-2023). Ms. Elwell previously served as Chief People Officer at J.E. Dunn Construction Company (2017-2021), as Vice President People Strategy / HR Business Partner of Walmart Corporation (2016-2017), as Vice President HR Business Partner Operations at DIRECTV, Inc. (2012-2015), and in various roles of increasing responsibility, including as Vice President, with Sprint Corporation (1997-2012; 2015-2016).

(f) Ms. Humphrey was appointed Senior Vice President, General Counsel and Corporate Secretary of Evergy, Inc. in June 2018. Ms. Humphrey previously served as Senior Vice President - Corporate Services and General Counsel of Great Plains Energy, Evergy Metro and Evergy Missouri West (2016-2018). She previously served as General Counsel (2010-2016) and Senior Vice President - Human Resources of Great Plains Energy, Evergy Metro and Evergy Missouri West (2012-2016). She served as Vice President - Human Resources of Great Plains Energy, Evergy Metro and Evergy Missouri West (2010-2012). She was Senior Director of Human Resources and Interim General Counsel of Great Plains Energy, Evergy Metro and Evergy Missouri West (2010) and Managing Attorney of Evergy Metro (2007-2010).

(g) Mr. King was appointed Senior Vice President and Chief Technology Officer of Evergy, Inc. in February 2020. He previously served as Senior Vice President, Information Technology and Chief Information Officer (2019) and Vice President, Information Technology and Chief Information Officer (2018-2019) of Evergy, Inc. Prior to that, he served as Vice President - Information Technology (2013-2018), as Senior Director of Information Technology Applications and Delivery (2013) and Director of Information Technology Applications (2011-2013) of Evergy Metro and Evergy Missouri West. Mr. King also served in various roles, including leadership roles, with Dish Network, CenturyLink, Sprint and Accenture.

(h) Mr. Reasoner was appointed Senior Vice President and Chief Nuclear Officer of Evergy, Inc., effective October 2025. Mr. Reasoner previously served as Vice President and Chief Nuclear Officer of Evergy, Inc (2019-2025). Mr. Reasoner also serves as President and Chief Executive Officer, Board of Directors Member, Chief Nuclear Officer and Treasurer of Wolf Creek Nuclear Operating Corporation (2019-present). He previously served as Senior Vice President, Chief Nuclear Officer of Wolf Creek Nuclear Operating Corporation (2018-2019) and Site Vice President of Wolf Creek Nuclear Operating Corporation (2014-2018). Prior to joining Wolf Creek Nuclear Operating Corporation, Mr. Reasoner served as Vice President of Engineering at Ameren Corporation's Callaway nuclear power plant and Site Vice President (2009-2014). Before joining Ameren's Callaway plant, Mr. Reasoner started his nuclear career at Arkansas Nuclear One and served in a variety of engineering roles.

(i) Mr. Gummig was appointed Vice President and Chief Accounting Officer of Evergy, Inc., effective April 2025. Mr. Gummig previously served as Director of External Reporting, Policy and Property Accounting of Evergy, Inc. (2023-2025). Prior to that, he held the position of Senior Manager of External Reporting and various other roles of increasing responsibility within Evergy, Inc.'s accounting organization (2012-2023). Mr. Gummig also served in various roles within the assurance practice of Ernst & Young (2009-2011).

Evergy Kansas Central, Inc.

Evergy Kansas Central, a Kansas corporation incorporated in 1924 and headquartered in Topeka, Kansas, is an integrated, regulated electric utility that engages in the generation, transmission, distribution and sale of electricity. Evergy Kansas Central serves approximately 751,000 customers located in central and eastern Kansas. Customers include approximately 651,100 residences, 94,800 commercial firms, and 5,100 industrials, municipalities and other electric utilities. Evergy Kansas Central's retail revenues averaged approximately 74% of its total operating revenues over the last three years. Wholesale firm power, bulk power sales, transmission and miscellaneous electric revenues accounted for the remainder of Evergy Kansas Central's revenues. Evergy Kansas Central is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter.

Evergy Metro, Inc.

Evergy Metro, a Missouri corporation incorporated in 1922 and headquartered in Kansas City, Missouri, is an integrated, regulated electric utility that engages in the generation, transmission, distribution and sale of electricity. Evergy Metro serves approximately 591,800 customers located in western Missouri and eastern Kansas. Customers include approximately 524,800 residences, 65,200 commercial firms, and 1,800 industrials, municipalities and other electric utilities. Evergy Metro's retail revenues averaged approximately 88% of its total operating revenues over the last three years. Wholesale firm power, bulk power sales and miscellaneous electric revenues accounted for the remainder of Evergy Metro's revenues. Evergy Metro is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Missouri and Kansas jurisdictional retail revenues for Evergy Metro averaged approximately 55% and 45%, respectively, of total retail revenues over the last three years.

ITEM 1A. RISK FACTORS

Utility Regulatory Risks:

Prices are established by regulators and may not be sufficient to recover costs or provide for a return on investment.
The prices that the FERC, KCC and MPSC authorize the utility subsidiaries of Evergy to charge significantly influence the Evergy Companies' results of operations, financial position and cash flows.

In general, utilities are allowed to recover in customer rates costs that were prudently incurred to provide utility service, plus a reasonable return on invested capital. There can be no assurance, however, that regulators will determine costs to have been prudently incurred. Further, the amounts approved by the regulators may not be sufficient to allow for a recovery of costs or provide for an adequate return on and of capital investments. Also, amounts that were approved by regulators may be subject to existing limitations in regulatory or legislative frameworks or appealed, modified, limited or eliminated by subsequent regulatory or legislative actions. The markets that the Evergy Companies operate in could also become deregulated resulting in costs that are unable to be recovered from customers. A failure to recover costs or earn a reasonable return on invested capital for any reason could negatively impact Evergy's ability to access capital at reasonable rates, impeding Evergy's ability to invest and develop infrastructure in its service territory, and may also have a material adverse effect on the results of operations, financial position and cash flows of Evergy.

The Evergy Companies are also exposed to cost-recovery shortfalls due to the inherent "regulatory lag" in the rate-setting process. Potential cost-recovery shortfalls occur because utility rates are generally based on historical information and, except for certain situations in which regulators allow for recovery of expenses through use of a formula that tracks costs, are not subject to adjustment between rate cases. These and other factors may result in under-recovery of costs or failure to earn the authorized return on investment, or both. Effective in July 2024, Evergy Kansas Central and Evergy Metro elected into a plant-in service accounting (PISA) provision permitted by Kansas law, allowing each to defer to a regulatory asset 90% of depreciation expense and associated return on investment associated with qualifying plants additions. These deferred amounts must be included in rate base during subsequent rate proceedings. However, Evergy Kansas Central and Evergy Metro will be unable to recover deferred amounts to the extent that inclusion of the incremental regulatory asset created by PISA causes base rates to increase more than 1.5% per year. Similarly, Evergy Metro and Evergy Missouri West elected into a PISA provision permitted by Missouri law that establishes a 2.5% annual limit on increases to the revenue requirement due to the inclusion of the incremental regulatory asset created by PISA. Increased capital expenditures could cause Evergy Kansas Central, Evergy Metro or Evergy Missouri West to exceed the applicable limitation resulting in an adverse impact to the Evergy Companies' results of operations, financial position and cash flows.

Furthermore, there remains uncertainty in the near-term outlook as to whether inflation will remain elevated compared to pre-pandemic inflation rates. Increases in inflation raise the Evergy Companies' costs for labor, materials and services, and a failure to recover these increased costs could result in under-recovery.

While the inflation rate and prices have increased, the Evergy Companies, and the energy industry as a whole, have experienced an upward trend in spending, especially with respect to new generation and infrastructure investments, which is likely to continue in the foreseeable future and could result in more frequent rate cases and requests for, and the continuation of, cost recovery mechanisms. The cost recovery efforts could face resistance from customers and other stakeholders especially in a rising cost environment, whether due to inflation or high fuel prices or otherwise, and/or in periods of economic decline or hardship. Significant increases in costs also could increase financing needs and otherwise adversely affect the Evergy Companies' business, financial position, results of operation or cash flows.

The Evergy Companies' business and capital investment plan calls for significant investment in capital improvements and additions, including the construction or acquisition of additional generation and transmission facilities, interconnection with data centers and modernizing existing infrastructure. Failure to timely recover the full investment costs of capital projects, the impact of renewable energy and energy efficiency programs, the impact

of tariffs and trade policy, other utility costs and expenses due to regulatory disallowances, regulatory lag or other factors could lead to increased expenses, lowered credit ratings, reduced access to capital markets, increased financing costs, lower flexibility due to constrained financial resources and increased collateral security requirements or reductions or delays in planned capital expenditures. In response to competitive, economic, political, legislative, public perception, customer affordability and regulatory pressures, Evergy's utility subsidiaries may be subject to rate moratoriums, rate refunds, limits on rate increases, lower allowed returns on investments or rate reductions, including phase-in plans designed to spread the impact of rate increases over an extended period for the benefit of customers. In addition, Transource, of which Evergy owns a 13.5% interest, is focused on the development of competitive electric transmission projects across the United States and faces similar risks with respect to projects located in regulatory jurisdictions outside of Kansas and Missouri. Any of these results could have a material adverse effect on the results of operations, financial position and cash flows of the Evergy Companies.

Legislative and regulatory requirements may increase costs and result in compliance penalties.
FERC, the North American Electric Reliability Corporation (NERC) and SPP have implemented and enforce an extensive set of transmission system reliability, cybersecurity and critical infrastructure protection standards that apply to public utilities. The MPSC and KCC have the authority to implement utility operational standards and requirements, such as vegetation management standards, facilities inspection requirements and quality of service standards. In addition, the Evergy Companies are also subject to health, safety and other requirements enacted by the Occupational Safety and Health Administration, the Department of Transportation, the Department of Labor and other federal and state agencies. As discussed more fully below, the Evergy Companies are also subject to numerous environmental laws and regulations, as well as laws and regulations related to nuclear power generation. The costs of complying with existing, new or modified regulations, standards and other requirements could have a material adverse effect on the results of operations, financial position and cash flows of the Evergy Companies. Furthermore, regulatory changes could result in operational changes that increase costs or adversely impact the Evergy Companies' prospects. In addition, failure to meet quality of service, reliability, cybersecurity, critical infrastructure protection, operational or other standards and requirements could expose the Evergy Companies to penalties, additional compliance costs or adverse rate consequences, any of which could have a material adverse impact on their results of operations, financial position and cash flows.

Environmental Risks:

Costs to comply with environmental laws and regulations, including those relating to air and water quality, waste management and hazardous substance disposal, protected natural resources and health and safety, are significant and may adversely impact operations and financial results.
The Evergy Companies are subject to extensive and evolving federal, state and local environmental laws, regulations and permit requirements relating to air and water quality, waste management and hazardous substance disposal, protected natural resources (such as wetlands, federally-listed species and other protected wildlife) and health and safety. See Item 1. Business - Environmental Matters and Note 15 to the consolidated financial statements for additional information. In general, over time these laws and regulations have become increasingly stringent and compliance with these laws and regulations require an increasing share of capital and operating resources, which may reduce the resources available for other business objectives, including capital investments.

Compliance with environmental laws, regulations and requirements requires significant capital and operating resources. Regulators may also disagree with the Evergy Companies' interpretation or application of environmental laws, regulations and requirements. The failure to comply with environmental laws, regulations and requirements could result in substantial fines, injunctive relief and other sanctions.

The EPA has begun issuing coal combustion residual (CCR) Part A and Part B rule extension application determinations for companies that applied for approval to operate unlined or clay-lined impoundments beyond April 2021. The Evergy Companies did not apply for an extension; however, the EPA's proposed determinations on applications include extensive CCR rule interpretations and compliance expectations that may impact all owners of CCR units. The new interpretations could require modified compliance plans such as different methods of CCR

unit closure. Additionally, more stringent remediation requirements for units that are in corrective action or forced to go into corrective action could result in substantial costs or operational impacts.

Environmental permits are subject to periodic renewal, which may result in more stringent permit conditions and limits. New facilities, or modifications of existing facilities, may require new environmental permits or amendments to existing permits. Delays in the environmental permitting process, public opposition and challenges, denials of permit applications, limits or conditions imposed in permits and the associated uncertainty may materially adversely affect the cost and timing of projects, and thus may materially adversely affect the results of operations, financial position and cash flows of the Evergy Companies. In addition, compliance with environmental laws, regulations and requirements could alter the way assets are managed, which in turn could result in retiring assets earlier than expected, recording asset retirement obligations (AROs) or having a regulator disallow recovery of costs that had been prudently incurred in connection with those assets. There is also a risk of lawsuits alleging violations of environmental laws, regulations or requirements, claiming creation of a public nuisance or other matters, and seeking injunctions or monetary damages or other relief.

Costs of compliance with environmental laws, regulations and requirements, or fines, penalties or negative lawsuit outcomes, if not recovered in rates from customers, could have a material adverse effect on the results of operations, financial position and cash flows of the Evergy Companies.

Financial Risks:

Evergy's business and capital investment plans depend, in part, on the viability of data centers and large load customers interconnecting with Evergy's utility subsidiaries.
The Evergy Companies are experiencing current and projected load demands that exceed recent experience, creating a business need for new power generating resources and transmission facilities. Much of this demand is driven by interconnecting with and providing power to data centers and large load customers to serve an increasingly digital economy and to support artificial intelligence. The business and capital investment plans of the Evergy Companies are focused on meeting these current and projected needs. If these increased demands for electricity do not occur as projected or are not sustained as projected, for any reason, it could have a material adverse effect on the Evergy Companies' financial results.

Financial market volatility or declines in the Evergy Companies' credit ratings may increase financing costs and limit access to the credit markets, which may adversely affect liquidity and financial results.
The Evergy Companies rely on funds from operations and access to the capital and credit markets to fund capital expenditures and for working capital and liquidity. Volatility in capital or credit markets, increases in interest rates, deterioration in the financial condition of the financial institutions on which the Evergy Companies rely, credit rating downgrades, delays in regulatory approvals for certain financings, a decrease in the market price of Evergy's common stock or a lack of demand for securities issued by the Evergy Companies or subsidiaries could have material adverse effects on the Evergy Companies. These effects could include, among others: reduced access to capital and increased cost of borrowed funds and collateral requirements; dilution resulting from equity issuances at reduced prices; increased nuclear decommissioning trust and pension and other post-retirement benefit plan funding requirements; reduced ability to pay dividends; rate case disallowance of costs of capital; reductions in or delays of capital expenditures; delayed access to the capital markets at opportune times; and limitations in the ability of Evergy to provide credit support for its subsidiaries.

The Evergy Companies plan to continue to make significant capital investments in natural gas and renewable generation and other forms of capacity and to enhance the customer experience, improve reliability and resiliency and improve efficiency, which are expected to be funded with cash flows from operations and issuances of debt, equity and hybrid securities. If cash flows from operations are lower than expected or the costs of these capital investments are higher than expected, additional debt, equity and hybrid securities will be required to fund the investments, which, in turn, may result in a decrease in the market value of Evergy's common stock, create pressure on the Evergy Companies' credit ratings or result in a ratings downgrade and increase their cost of capital. While the Evergy Companies currently expect sufficient available debt and equity capital from public and private funding sources, there is no guarantee such sources will be available in the future. Further, Evergy Kansas Central and

Evergy Metro have outstanding tax-exempt bonds with interest rates that are determined each week. The bondholders of these tax-exempt bonds are permitted to tender the tax-exempt bonds to the issuer for purchase and, if tendered, the issuer is obligated to purchase any such bonds that cannot be remarketed to other investors, which could adversely impact liquidity. Finally, market disruption and volatility could have an adverse impact on Evergy's lenders, suppliers and other counterparties or customers, causing them to fail to meet their obligations.

Evergy is a holding company and relies on the earnings of its subsidiaries to meet its financial obligations.
Evergy is a holding company with no significant operations of its own. The primary source of funds for Evergy's payment of dividends to its shareholders and its other financial obligations is dividends paid to it by its direct subsidiaries, particularly Evergy Kansas Central, Evergy Metro and Evergy Missouri West. Evergy's subsidiaries are separate legal entities and have no obligation to provide Evergy with funds. The ability of Evergy's subsidiaries to pay dividends or make other distributions, and accordingly, Evergy's ability to pay dividends on its common stock and meet its financial obligations, principally depends on the earnings and cash flows, capital requirements and general financial position of its subsidiaries, as well as regulatory factors, financial covenants, general business conditions and other matters.

In addition, the Evergy Companies are subject to certain corporate and regulatory restrictions and financial covenants that could affect their ability to pay dividends. Under the Federal Power Act, Evergy Kansas Central, Evergy Metro and Evergy Missouri West generally can pay dividends only out of retained earnings. Each of Evergy Metro and Evergy Missouri West has committed to Missouri regulators to not pay dividends to Evergy if its credit rating falls below BBB- for S&P Global Ratings or Baa3 for Moody's Investors Service. Each of Evergy Kansas Central and Evergy Metro has committed to Kansas regulators to not pay dividends to Evergy if (i) the payment would result in an increase in the utility's debt level (excluding short-term debt and debt due within one year) above 60 percent of its total capitalization, absent approval from the KCC or (ii) if its credit rating falls below BBB- for S&P Global Ratings or Baa3 for Moody's Investors Service. Under various debt agreements, the Evergy Companies are also required to maintain a consolidated indebtedness to consolidated total capitalization ratio of not more than 0.65 to 1.00, which could restrict the amount of dividends the Evergy Companies are permitted to pay. Evergy cannot guarantee dividends will be paid in the future or that, if paid, dividends will satisfy announced targets or investor expectations or be paid with the same frequency as in the past. Additionally, Evergy may not declare or pay any cash dividend or distribution on its capital stock during any period in which Evergy defers interest on its outstanding junior subordinated notes.

In addition, from time to time Evergy has in the past and may in the future guarantee debt obligations of its subsidiaries. Under the financing agreements to which Evergy is a party, a guarantee of debt may be considered indebtedness for purposes of complying with financial covenants that dictate the extent to which Evergy can borrow money, and any guarantee payments could adversely affect Evergy's liquidity and ability to service its own debt obligations.

Supply chain disruptions, tariffs and inflation could negatively impact the Evergy Companies' operations and corporate strategy.
The operations and business plans of the Evergy Companies depend on the global supply chain to procure the equipment, materials and other resources necessary to build and provide services in a safe and reliable manner. The delivery of components, materials, equipment and other resources that are critical to the Evergy Companies' business operations and corporate strategy has been restricted by domestic and global supply chain uncertainty. This has resulted in the shortage of critical items. International tensions from any source, including the ramifications of regional conflict or increased tariffs, could further exacerbate the global supply chain uncertainty. These disruptions and shortages could adversely impact business operations and corporate strategy. The current presidential administration has implemented tariffs on certain imported goods and may impose additional tariffs. The constraints in the supply chain could restrict the availability and delay the construction, maintenance or repair of items that are needed to support normal operations or are required to execute on the Evergy Companies' corporate strategy for continued capital investment in utility equipment and impact the strategy to modernize its generation fleet. These disruptions and constraints could have a material adverse effect on the business, results of operations, financial position and cash flows of the Evergy Companies.

Supply chain disruptions have contributed to higher prices of components, materials, equipment and other needed commodities. An extended duration or an ongoing increase in the severity of supply chain and inflationary disruptions, including increased tariffs, could result in continued inflation, further extend lead times and result in higher cost of capital. While the Evergy Companies generally recover increases in costs from customers through rates in the Evergy Companies' regulated jurisdictions, short-term increases may not be recovered due to "regulatory lag." Failure to recover increased costs could have a material adverse effect on the business, results of operations, financial position and cash flows of the Evergy Companies. Additionally, heightened inflation raises the Evergy Companies' costs for labor, materials and services, and failure to secure these on reasonable terms may adversely impact the Evergy Companies' business, results of operations, financial position and cash flows.

Public health crises, epidemics, or pandemics could adversely affect the Evergy Companies' business functions, financial position, liquidity, and results of operations.
Public health crises, epidemics, or pandemics and any related government responses may adversely impact the economy and financial markets and could have a variety of adverse impacts on the Evergy Companies, including a decrease in revenues, increased credit loss expense; increases in past due accounts receivable balances; and access to the capital markets at unreasonable terms or rates.

Public health crises, epidemics, or pandemics and any related government responses could also impair the Evergy Companies' ability to develop, construct, and operate facilities. Risks include extended disruptions to supply chains and inflation, resulting in increased costs for labor, materials, and services, which could adversely impact the Evergy Companies' ability to implement their corporate strategy. The Evergy Companies may also be adversely impacted by labor disruptions and productivity as a result of infections, employee attrition, and a reduced ability to replace departing employees as a result of employees who leave or forego employment to avoid any required precautionary measures.

Despite the Evergy Companies' efforts to manage the impacts of public health crises, epidemics, or pandemics that may occur in the future, the extent to which they may affect them depends on factors beyond their knowledge or control. As a result, the Evergy Companies are unable to determine the potential impact any such public health crises, epidemics, or pandemics may have on their business plans and operations, liquidity, financial position, and results of operations.

Increasing costs associated with defined benefit retirement and postretirement plans, health care plans and other employee benefits could adversely affect Evergy's financial position and liquidity.
Evergy maintains defined benefit retirement and other post-retirement employee benefit plans for certain current and former employees. The costs of these plans depend on a number of factors, including the rates of return on plan assets, the level and nature of the provided benefits, discount rates, the interest rates used to measure required minimum funding levels, changes in benefit design, changes in laws or regulations and the amount of any required or voluntary contributions to the plans. The Evergy Companies have substantial unfunded liabilities under these plans. Also, if the rate of retirements exceeds planned levels, these plans experience adverse market returns on investments or interest rates fall, required or voluntary contributions to the plans could be material. In addition, changes in accounting rules and assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions, including projected retirements, could have an adverse impact on the results of operations, financial position and cash flows of the Evergy Companies.

The costs of providing health care benefits to employees and retirees have increased in recent years and may continue to rise in the future. Future legislative changes related to health care could also cause significant changes to benefit programs and costs. The increasing costs associated with health care plans could have an adverse impact on the results of operations, financial position and cash flows of the Evergy Companies.

The Evergy Companies are subject to commodity and other risks associated with energy markets.
The Evergy Companies are required to maintain generation capacity that satisfies regulatory mandates and are obligated to provide power when required by the SPP or pursuant to contractual obligations. Although the Evergy Companies generally have regulatory mechanisms that allow them to recover the cost of fuel and purchased power

necessary to satisfy these requirements, regulatory or legislative actions could limit, eliminate or delay recovery of these expenses after the expenses have been incurred.

The Evergy Companies engage in the wholesale and retail sale of electricity and the wholesale purchase of electricity as part of their regulated electric operations in addition to energy marketing activities and the management of third-party generation facilities. These activities expose the Evergy Companies to risks associated with the price of electricity and other energy-related products, as well as credit exposure to their counterparties. Exposure to these risks is affected by a number of factors, including the availability and cost of fuel and power that the Evergy Companies purchase on the wholesale markets to serve customer load or to satisfy their regulatory or contractual obligations, the ability or effectiveness of strategies utilized by the Evergy Companies to hedge these risks, the extent to which the Evergy Companies may be required to post collateral for the benefit of third parties and the risk that counterparties fail to fulfill their obligations to the Evergy Companies. Market volatility can increase or create unanticipated risks. Regional transmission organizations and independent system operators may also retroactively reprice transactions following execution.

Subject to certain regulatory constraints, the Evergy Companies use derivative instruments, such as transmission congestion rights (TCRs), swaps, options, futures and forwards, to manage commodity and financial risks. Losses could be recognized as a result of volatility in the market values of these contracts, if a counterparty fails to perform or if the underlying transactions, which the derivative instruments are intended to hedge, fail to materialize. The valuation of these financial instruments can involve management's judgment or the use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts. The Evergy Companies cannot assure that their risk management practices will be effective or will mitigate all risks.

The results of operations, financial position and liquidity of the Evergy Companies could be materially adversely affected if the Evergy Companies fail to recover, or experience a delay in the recovery of, fuel and purchased power expenses; if the Evergy Companies fail to adequately hedge or mitigate commodity or energy market risks; if the Evergy Companies are required to provide collateral in amounts greater than planned; if energy marketing transactions are retroactively repriced; or if counterparties fail to fulfill obligations to the Evergy Companies.

Tax legislation and an inability to utilize tax credits could adversely impact results of operations, financial position and liquidity.
Tax laws and regulations can adversely affect, among other things, financial results, liquidity, credit ratings and the valuation of assets, such as deferred income tax assets. The Evergy Companies regularly assess their ability to utilize tax benefits, including those in the form of net operating loss (NOL), tax credit and other tax carryforwards, that are recorded as deferred income tax assets on their balance sheets to determine whether a valuation allowance is necessary. A reduction in, or disallowance of, these tax benefits could have an adverse impact on the financial results and liquidity of the Evergy Companies.

Changes in corporate tax rates or policy changes, as well as any inability to generate enough taxable income in the future to utilize all tax benefits before they expire, could have an adverse impact on the results of operations, financial position and liquidity of the Evergy Companies. In addition, the Evergy Companies construct and operate renewable energy facilities that generate tax credits that reduce federal income tax obligations. The Evergy Companies are also eligible under current law for production tax credits related to the generation of electricity from nuclear energy. The One Big Beautiful Bill Act (OBBBA) was signed into law on July 4, 2025. The OBBBA, among other things, changed most of the federal renewable energy initiatives. Furthermore, the amount of tax credits is dependent on several factors, including the amount of electricity produced and the applicable tax credit rate. A variety of factors, including transmission constraints, IRS interpretation on eligibility as well as the calculation of the credits, a change in law or regulation, the ability to timely complete construction of renewable energy facilities, adverse weather conditions and breakdown or failure of equipment, could significantly reduce these tax credits, which could have an adverse impact on the results of operations and financial position of the Evergy Companies.

The anticipated benefits of the Evergy Companies' strategy may not be realized.
The Evergy Companies' strategy includes maintaining rigorous cost management and planned increases in capital investment levels to meet expected electricity demand growth and economic development in their service territory. The Evergy Companies' strategy also includes a different mix of capital investments than has been pursued in the past, including significant capital investments in natural gas and renewable generation and battery storage capacity. The Evergy Companies' strategy is expected to result in the modernization and expansion of the generation fleet to support economic expansion in Kansas and Missouri and, as reflected in their IRPs, is expected in the future to be accompanied by the retirement of older coal-fired generation units and/or conversion of coal-fired generation resources to natural gas. If regulators determine that the modernization and expansion of the generation fleet or the retirement or conversion of coal generation facilities were not prudent, they could prohibit the Evergy Companies from recovering, or earning a return on, the investments in those facilities that were prudent when the investments were originally made. This concept is known as a "stranded asset," and generation retirements or conversion outside of those contemplated in the IRP increase the risk that regulators will disallow the recovery of otherwise prudent investments. In addition, the Evergy Companies may in the future utilize legislative mechanisms known as securitization to facilitate the retirement of coal-fired generation, which will eliminate future returns on the investment that was originally made by the Evergy Companies in those coal-fired generating facilities and reduce the Evergy's Companies' results of operations and financial position.

No assurance can be given that the expected electricity demand growth and economic development in the Evergy Companies' service territory will occur, or that the Evergy Companies will be successful in implementing their strategy in a timely manner or at all, and a failure to do so could have a material adverse effect on the results of operations, financial position and cash flows of the Evergy Companies and have an adverse impact on the price of Evergy’s common stock.

The price of Evergy common stock may experience volatility.
The price of Evergy common stock may be volatile. Some of the factors that could affect the price of Evergy common stock are Evergy's earnings; the ability of the Evergy Companies to implement their strategic plan; the ability of Evergy to deploy capital; actions by regulators including authorized return on equity and equity capital structure levels that could impact the ability to attract capital; anticipated demand for electricity from large load customers not occurring as projected or not sustained as projected; and statements in the press or investment community about the Evergy Companies' strategy, earnings per share or growth prospects, results of operations or financial position. Negative perceptions or publicity from increasing scrutiny of environmental, social and governance practices could also adversely impact Evergy's stock price. Also, individuals or entities, such as activist shareholders and special interest groups, may seek to influence the Evergy Companies' strategic plan or take other actions that could disrupt the Evergy Companies' business, financial results or operations and could adversely impact Evergy's stock price. In addition, the Evergy Companies operate almost exclusively in Kansas and Missouri and this concentration may increase exposure to risks arising from unique local or regional factors. Furthermore, domestic and international market conditions and economic factors and political events unrelated to the performance of Evergy (including geopolitical conflicts) may also affect Evergy's stock price. For these reasons, shareholders should not rely on historical trends in the price of Evergy common stock to predict the future price of Evergy's common stock.

Evergy has recorded goodwill that could become impaired and adversely affect financial results.
As required by generally accepted accounting principles (GAAP), Evergy recorded a significant amount of goodwill on its balance sheet in connection with completion of the merger that resulted in the formation of Evergy. Evergy assesses goodwill for impairment on an annual basis or whenever events or circumstances occur that would indicate a potential for impairment. If goodwill is deemed to be impaired, Evergy may be required to incur non-cash charges that could materially adversely affect its results of operations.

Customer and Weather-Related Risks:

Evergy is subject to wildfire risk.
Wildfires have the potential to negatively affect communities within the Evergy Companies' service territories and the surrounding areas, as well as its network of electric transmission and distribution lines and facilities. The

possibility of wildfires and the risk of damage to the Evergy Companies' network and facilities resulting therefrom may be exacerbated by severe weather events and the effects of climate change. The continued expansion of the wildland-urban interface has also increased wildfire risk to communities in the Evergy Companies' service territories. While the Evergy Companies proactively take steps to mitigate wildfire risk in the areas of its electrical assets, wildfire risk is always present. Kansas has enacted legislation that partially mitigates wildfire-related liability exposure for Kansas public utilities by establishing a two-year statute of limitations for wildfire-related claims and imposing a cap on punitive damages awarded under a fire-related claim. The law also requires plaintiffs to prove fire-related claims by a preponderance of the evidence. Despite these statutory limitations, the Evergy Companies could still be held liable for damages incurred as a result of wildfires or incur reputational harm if it was determined that the wildfires were caused by or enhanced due to any fault of the Evergy Companies. In addition, while the Evergy Companies maintain wildfire insurance, insurance coverage may not be sufficient to cover all losses the Evergy Companies may incur as a result of wildfires. Wildfires could also lead to significant financial distress, credit rating downgrades, limits on the ability to access capital markets and further increased costs for wildfire insurance or lack of availability thereof. Insufficient wildfire insurance coverage, increased wildfire insurance costs and a lack of wildfire insurance availability could adversely impact the Evergy Companies' results of operations, financial position and cash flows. Furthermore, any damage caused to the Evergy Companies' assets, loss of service to customers or liability imposed as a result of wildfires could negatively impact Evergy's results of operations, financial position and cash flows.

Changes in electricity consumption could have a material adverse effect on Evergy's results of operations, financial position and cash flows.
Change in customer behaviors in response to energy efficiency programs, changing conditions and preferences or changes in the adoption of technologies could affect the consumption of energy by customers. Federal and state programs exist to influence the way customers use energy and regulators have mandates to promote energy efficiency. Conservation programs and customers' level of participation in the programs could have a material adverse effect on the results of operations, financial position and cash flows of the Evergy Companies.

Technological advances, energy efficiency and other energy conservation measures have reduced and will continue to reduce customer electricity consumption. The Evergy Companies predominately generate electricity at central station power plants to achieve economies of scale and produce electricity at a competitive cost. Self-generation and distributed generation technologies, including microturbines, wind turbines, fuel cells and solar cells, as well as those related to the storage of energy produced by these systems, have become economically competitive with the manner and price at which the Evergy Companies sell electricity. There is also a perception that generating or storing electricity through these technologies is more environmentally friendly than generating electricity with fossil fuels. Increased adoption of these technologies could reduce electricity demand and the pool of customers from whom fixed costs are recovered, resulting in under recovery of the fixed costs of the Evergy Companies. Increased self-generation and the related use of net energy metering, which allows self-generating customers to receive bill credits for surplus power, could put upward price pressure on remaining customers. If the Evergy Companies are unable to adjust to reduced electricity demand and increased self-generation and net energy metering, their results of operations, financial position and cash flows could be adversely affected.

Changes in customer electricity consumption due to sustained financial market disruptions, downturns or sluggishness in the economy or other factors may also adversely affect the results of operations, financial position and cash flows of the Evergy Companies.

Weather is a major driver of the results of operations, financial position and cash flows of the Evergy Companies and the Evergy Companies are subject to risks associated with climate change.
Weather conditions directly influence the demand for and price of electricity. The Evergy Companies are significantly impacted by seasonality, and, due to energy demand created by air conditioning load, their highest revenues are typically recorded in the third quarter. Unusually mild winter or summer weather can adversely affect sales. In addition, severe weather and events, including tornados, snow, fire, rain, flooding, drought and ice storms, can be destructive and cause outages and property damage that can result in increased expenses, lower revenues and additional restoration costs. Storm reserves established by the Evergy Companies may be insufficient and rates may not be adjusted in a timely manner, or at all, to recover these costs. Additionally, because many of the Evergy

Companies' generating stations utilize water for cooling, low water and flow levels can increase maintenance costs at these stations, result in limited power production and require modifications to plant operations. High water conditions can also impair planned deliveries of fuel to generating stations or otherwise adversely impact the ability of the Evergy Companies to operate these stations. Climate change may produce more frequent or severe weather events, such as storms, droughts or floods. These events could lead to unforeseen changes in water supply quality and create additional costs related to water treatment and complying with environmental discharge requirements. Climate change events could also impact the economic health of the Evergy Companies' service territories. An increase in the frequency or severity of extreme weather events or a deterioration in the economic health of the Evergy Companies' service territories could have a material adverse effect on the results of operations, financial position and cash flows of the Evergy Companies.

Additionally, the Evergy Companies have been increasing their renewable resources and expect to continue to add renewable capacity in the future. The production of energy from wind and solar facilities depends heavily on suitable weather conditions, which are variable. When wind or solar conditions are unfavorable or below estimates, electricity production can be substantially below expectations.

In addition, policy, legal and regulatory efforts to influence climate change, such as efforts to reduce GHG emissions, impose a tax on emissions and create incentives for low-carbon generation and energy efficiency, could result in reduced sales and require significant costs to respond to such efforts. These efforts could also result in the early retirement of generation facilities, which could result in stranded costs if regulators disallow recovery of investments that were prudent when originally made and included in rates. Evergy has a goal to achieve net-zero CO_2e emissions, for scope 1 and 2 emissions, by 2050 through the responsible transition of the Evergy Companies' generation fleet. This time frame is consistent with the majority of industry peers with stated net-zero emissions goals. The trajectory and timing of achieving emissions reductions and the 2050 goal are expected to be dependent on the evolution of Evergy's IRPs and many external factors, including enabling technology developments, trends in the total demand for electricity, the reliability of the power grid, availability of transmission capacity, supportive energy policies and regulations, and other factors. These external factors are outside of Evergy's direct control, and without these enabling factors, Evergy cannot be confident in achieving its net-zero carbon reduction goal. Any of the foregoing could adversely affect the results of operations, financial position and cash flows of the Evergy Companies and the market prices of Evergy's common stock.

Operational Risks:

The Evergy Companies are exposed to risks associated with the ownership and operation of a nuclear generating unit, which could adversely impact the Evergy Companies' business and financial results.

Evergy indirectly owns 94% of Wolf Creek, with Evergy Kansas South and Evergy Metro each owning 47% of the nuclear plant. Such ownership exposes the Evergy Companies to various risks unique to the nuclear industry. Damages, decommissioning or other costs could exceed the Evergy Companies' ability to recover such costs through rates or other mechanisms such as decommissioning trust assets or through external insurance coverage, including statutorily required nuclear incident insurance. The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities, including Wolf Creek. In the event of non-compliance, the NRC has the authority to impose fines, shut down the facilities, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Additionally, the non-compliance of other nuclear facility operators with applicable regulations or the occurrence of a serious nuclear incident anywhere in the world could result in increased regulation of the nuclear industry. Such events could increase Wolf Creek's costs and impact the financial results of the Evergy Companies or result in a shutdown of Wolf Creek.

An extended outage of Wolf Creek, whether resulting from NRC action, an incident at the plant or otherwise, could have a material adverse effect on the results of operations, financial position and cash flows of the Evergy Companies in the event replacement power, damages, and other costs exceed or are not recovered through rates, insurance or decommissioning trust assets. If a long-term outage occurred, the state regulatory commissions could reduce rates by excluding the Wolf Creek investment from rate base. Wolf Creek commenced operations in 1985 and the age of Wolf Creek may increase the risk of unplanned outages and may result in higher maintenance costs.

On an annual basis, Evergy Kansas South and Evergy Metro are required to contribute money to tax-qualified trusts that were established to pay for decommissioning costs at the end of the unit's life. The amount of contributions varies depending on estimates of decommissioning expenses and projected return on trust assets. If the actual return on trust assets is below the projected level or actual decommissioning costs are higher than estimated, Evergy Kansas South and Evergy Metro could be responsible for the balance of funds required and may not be allowed to recover the balance through rates.

The Evergy Companies are also exposed to other risks associated with the ownership and operation of a nuclear generating unit, including, but not limited to, (i) potential liability associated with the potential harmful effects on the environment and human health resulting from the operation of a nuclear generating unit, (ii) the storage, handling, disposal and potential release (by accident, through third-party actions or otherwise) of radioactive materials and (iii) uncertainties with respect to contingencies and assessments if insurance coverage is inadequate. Under the structure for insurance among owners of nuclear generating units, Evergy Kansas South and Evergy Metro are also liable for potential retrospective premium assessments (subject to a cap) per incident at any commercial reactor in the country and losses in excess of insurance coverage.

In addition, Wolf Creek is reliant on a sole supplier for nuclear fuel assembly fabrication and related services. The supplier has in the past been the subject of Chapter 11 reorganization proceedings, and an extended outage of Wolf Creek could occur if the supplier is not able to perform under its contracts with Wolf Creek. Switching to another supplier could take an extended amount of time and would require NRC approval. An extended outage at Wolf Creek could affect the amount of Wolf Creek investment included in customer rates and could have a material adverse effect on the Evergy Companies' financial results.

Operational risks may adversely affect the Evergy Companies.
The operation of electric generation, transmission, distribution and information systems involves many risks, including breakdown or failure of equipment; aging infrastructure; employee error or contractor or subcontractor failure; problems that delay or increase the cost of returning facilities to service after outages; limitations that may be imposed by equipment conditions or environmental, safety or other regulatory requirements; fuel supply or fuel transportation reductions or interruptions; labor disputes; difficulties with the implementation or operation of information systems; transmission scheduling constraints; and catastrophic events such as fires, floods, droughts, explosions, terrorism or acts of war, severe weather, pandemics, cyberattacks or other similar occurrences. Many of the Evergy Companies' generation, transmission and distribution resources are aged, which increases the risk of unplanned outages, reduced generation output and higher maintenance expense. Any equipment or system outage or constraint can, among other things, reduce sales, increase costs and affect the ability to meet regulatory service metrics, customer expectations and regulatory reliability and security requirements.

The Evergy Companies have general liability and property insurance to cover a portion of their facilities, but such policies do not cover transmission or distribution systems, are subject to certain limits and deductibles and do not include business interruption coverage. Insurance coverage may not be available in the future at reasonable costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any facilities may not be sufficient to restore the loss or damage. Certain insurers are also choosing to limit their exposure to companies with coal-fired generation, which may result in increased premiums and reduced scope of coverage. These and other operating events may reduce revenues or increase costs, or both, and could have a material adverse effect on the results of operations, financial position and cash flows of the Evergy Companies.

Physical and cybersecurity breaches, criminal activity, terrorist attacks, acts of war and other disruptions to facilities or technology infrastructure could interfere with operations, expose the Evergy Companies or their customers or employees to a risk of loss, expose the Evergy Companies to legal or regulatory liability and cause reputational and other harm.
The Evergy Companies rely upon technology networks and systems to process, transmit and store electronic information, and to manage or support a variety of business processes and activities, including the generation, transmission and distribution of electricity, supply chain functions and the invoicing and collection of payments from customers. The Evergy Companies also use technology networks and systems to record, process and summarize financial information and results of operations for internal reporting purposes and to comply with

financial reporting, legal and tax requirements. These networks and systems are in some cases owned or managed by third-party service providers. In the ordinary course of business, the Evergy Companies collect, store and transmit sensitive data including operating information, proprietary business information and personal information belonging to customers and employees.

The Evergy Companies' technology networks and infrastructure, as well as the networks and infrastructure belonging to third-party service providers, are vulnerable to damage, disruptions or shutdowns due to attacks or breaches by hackers or other unauthorized third parties; error or malfeasance by employees, contractors or service providers; unintended consequences related to software or hardware upgrades, additions or replacements; malicious software code; vulnerabilities in third-party software code; telecommunication failures; the lack of availability of qualified employees and contractors; natural disasters or other catastrophic events; or criminal activity, terrorist attacks or acts of war. The Evergy Companies use technology to enable remote-working arrangements, which may increase or expose previously unknown vulnerabilities. Public reports have indicated an increase in cyberattacks in general due, in part, to employees working remotely and the proliferation of the different ways in which people interact with their technology infrastructure.

The occurrence of any of these events could, among other things, impact the reliability or safety of the Evergy Companies' generation, transmission and distribution systems and information systems; result in the erasure of data or render the Evergy Companies' equipment, or the equipment of third-party service providers, unusable; impact the Evergy Companies' ability to conduct business in the ordinary course; reduce sales; expose the Evergy Companies and their customers, employees and vendors to a risk of loss or misuse of information; result in legal claims or proceedings, liability or regulatory penalties; damage the Evergy Companies' reputation; or otherwise harm the Evergy Companies' results of operations, financial position and cash flows. The Evergy Companies can provide no assurance that they will be able to identify and remediate all security or system vulnerabilities or that unauthorized access or error will be identified and remediated.

The Evergy Companies are subject to laws and rules issued by multiple government agencies concerning cybersecurity and safeguarding their customer and business information. For example, NERC has issued comprehensive regulations and standards surrounding the security of the bulk power system, including both physical and cybersecurity, and continually evaluates the necessity for updates and new requirements with which the Evergy Companies must comply. The Evergy Companies are subject to recurring, independent, third-party audits with respect to adherence to these regulations and standards. The NRC also has issued regulations and standards related to the protection of critical digital assets at nuclear power plants. Compliance with NERC and NRC rules and standards, and rules and standards promulgated by other regulatory agencies from time to time or future legislation, will increase the Evergy Companies' compliance costs and their exposure to the potential risk of violations of these rules, standards or future legislation, which includes potential financial penalties. Furthermore, the non-compliance by other utilities subject to similar regulations or the occurrence of a serious security event at other utilities could result in increased regulation or oversight, both of which could increase the Evergy Companies' costs and adversely impact their financial results.

Additionally, the Evergy Companies cannot predict the impact that any future technology or malicious attack may have on the energy industry in general. The electric utility industry, both within the United States and internationally, has experienced physical and cybersecurity attacks on energy infrastructure such as power plants, substations and related assets in the past, and there will likely be more attacks in the future. Geopolitical matters, including terrorist attacks and acts of war, may increase the likelihood of such attacks. The Evergy Companies have been subject to attempted cyberattacks from time to time, and will likely continue to be subject to such attempted attacks, but these prior attacks have not had a material impact on their operations. However, because technology is increasingly complex and cyber-attacks are increasingly sophisticated and more frequent, there can be no assurance that such incidents will not have a material adverse effect on the Evergy Companies in the future. The Evergy Companies' facilities and systems could be direct targets or indirect casualties of such attacks. The effects of such attacks could include disruption to the Evergy Companies' generation, transmission and distribution, and information systems or to the electrical grid in general, reduced sales and could increase the cost of insurance coverage. Furthermore, although the Evergy Companies maintain information security risk insurance coverage,

such insurance may not be adequate to cover any associated losses. Any of the foregoing could have a material adverse impact on the Evergy Companies' results of operations, financial position and cash flows.

Artificial intelligence (AI) is an emerging area of technology that has the potential to impact various aspects of the Evergy Companies' business operations and customer interactions.

Generative AI technologies are still in their early stages of development and deployment. Ineffective or inadequate AI development or deployment practices by Evergy, its subsidiaries or third-party vendors could result in unintended consequences. While the Evergy Companies seek contractual protections with its third-party vendors regarding the use of AI technology, the Evergy Companies may not have full awareness of, or control or visibility over the quality, performance, security or compliance of the products and services that incorporate AI-related technology used by such vendors. AI algorithms that the Evergy Companies or its third-party vendors use may be flawed or may be based on datasets that are biased or insufficient. These limitations or failures, or inaccurate results generated as a result of the Evergy Companies' employees', contractors' or vendors' use or misuse of generative AI technologies could lead to operational interruptions or otherwise adversely affect the Evergy Companies' business, reputation or financial results. Developing, testing and deploying resource-intensive AI systems may require additional investment and increase the Evergy Companies' costs. In addition, the rapidly evolving nature of AI technologies may cause new laws and regulations to be enacted which could dramatically affect business practices, including the costs to comply with such new laws and regulations. The future development of AI technologies and the nature of any related new laws and regulations, and their costs and consequences, cannot be reasonably predicted at this time.

The cost and schedule of capital projects, including the construction of new natural gas and renewable generating facilities, may materially change and expected performance may not be achieved.

The Evergy Companies' business is capital intensive and includes significant construction projects. The risks of any capital project include: actual costs may exceed estimated costs; regulators may disallow, limit or delay the recovery of all or part of the cost of, or a return on, a capital project; increased inflation or the imposition of tariffs on imported goods may render previously estimated costs to be inaccurate; delays due to regulatory or judicial action; risks associated with the capital and credit markets to fund projects; delays in receiving, or failure to receive, necessary permits, approvals and other regulatory authorizations; unforeseen engineering problems or changes in project design or scope; the failure of suppliers and contractors to perform as required under their contracts; inadequate availability or increased cost of labor or materials, including commodities such as steel, copper and aluminum that may be subject to uncertain or increased tariffs; inclement weather; new or changed laws, regulations and requirements, including environmental and health and safety laws, regulations and requirements; and other events beyond the Evergy Companies' control may occur that may materially affect the schedule, cost and performance of these projects.

The completion of capital projects, including the construction of natural gas and renewable generating facilities, involves substantial risks that could materially affect the Evergy Companies' financial condition, results of operations, or liquidity. The Evergy Companies' ability to complete capital projects in a timely and cost-effective manner and within budget is contingent upon many variables including on the availability of adequate internal and external resources, such as employees and qualified contractors and the availability of materials. The Evergy Companies have selected a single vendor to supply the power island equipment to its new natural gas plants. The Evergy Companies face the potential of project delays if the vendor is unable to meet contractual deadlines. Causes and impacts could include material constraints or disruptions, financial hardship, geopolitical issues, or permitting issues. The Evergy Companies have entered into certain equipment purchases ahead of regulatory approval in an attempt to adhere to anticipated project timelines and expected completion dates. If any of these projects are canceled for any reason, including failure to receive necessary regulatory approvals, supply chain issues and/or siting or environmental permits, significant cancellation penalties under the equipment purchase orders and construction contracts could occur. In addition, if any construction work or investments have been recorded as an asset, an impairment may need to be recorded in the event the project is canceled. These events could increase costs and have a material adverse impact on the Evergy Companies' results of operations, financial position and cash flows. See Part II, Item 7, MD&A - Liquidity and Capital Resources - Capital Expenditures for additional information.

These and other risks could also cause the Evergy Companies to defer or limit capital expenditures, materially increase the costs of capital projects, incur penalties from the SPP for insufficient capacity reserve margins, delay the in-service dates of projects, adversely affect the performance of the projects and require the purchase of electricity on the wholesale market, at potentially more expensive prices, until the projects are completed. These risks may have a material adverse impact on the Evergy Companies' results of operations, financial position and cash flows.

Failure to attract and retain an appropriately qualified workforce or to maintain satisfactory collective bargaining agreements could negatively impact the Evergy Companies' business and operations and adversely impact the Evergy Companies' results of operations, financial position and cash flows.
The Evergy Companies' workforce includes professional, managerial and technical employees. Failure to attract and retain qualified talent, successfully transition retirements with adequate replacements, or source qualified contractors could impede the Evergy Companies' strategy and/or adversely impact the Evergy Companies' ability to execute on their strategy. For example, certain skills, such as those related to construction, maintenance and repair of transmission and distribution systems are in high demand and have a limited supply. Evergy competes for qualified employees with these skills on a national level.

A significant portion of the Evergy Companies' workforce is represented by five local unions of the IBEW and one local union of the UGSOA. The Evergy Companies currently have labor agreements that expire at varying times from 2026 through 2028. A failure to successfully negotiate these collective bargaining agreements could result in a labor disruption and have an adverse impact on the Evergy Companies' operations and results of operations.

The Evergy Companies' strategic plan includes enhanced technology and transmission and distribution investments and a reduction in reliance on coal-fired generation. The Evergy Companies will need to attract and retain personnel that are qualified to implement the Evergy Companies' strategy and may need to retrain or reskill certain employees to support the Evergy Companies' long-term objectives. A failure to attract and retain qualified employees, retrain or reskill existing employees and maintain satisfactory collective bargaining agreements could have an adverse impact on the results of operations, financial position and cash flows of the Evergy Companies.

The structure of the regional power market in which the Evergy Companies operate could have an adverse effect on their results of operations, financial position and cash flows.
Evergy Kansas Central, Evergy Metro and Evergy Missouri West are members of the SPP regional transmission organization, and each has transferred operational authority (but not ownership) of their transmission facilities to the SPP. The SPP's Integrated Marketplace determines which generating units among market participants should run, within the operating constraints of a unit, at any given time. The SPP's rules are primarily designed to provide for maximum cost-effectiveness. If Evergy Kansas Central's, Evergy Metro's or Evergy Missouri West's generating resources are not dispatched, each could experience decreased levels of wholesale electricity sales.

The Evergy Companies' strategic plan includes adding a significant amount of natural gas and renewable generation. Transmission constraints and delays in the transmission planning and construction processes could impair the ability of the Evergy Companies to sell and transmit electricity generated by these generation facilities, which could have an adverse impact on the results of operations, financial position and cash flows of the Evergy Companies.

In addition, the rules governing the various regional power markets, including the SPP, may change from time to time and such changes could impact the costs and revenues of the Evergy Companies.

Litigation Risks:

The outcome of legal proceedings cannot be predicted. An adverse finding could have a material adverse effect on the Evergy Companies' results of operations, financial position and cash flows.
The Evergy Companies are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. The outcome of these matters cannot be determined, nor, in many cases, can the liability that could potentially result from each case be reasonably estimated. The liability that the Evergy Companies may incur

with respect to any of these cases may be in excess of amounts currently accrued and insured against with respect to such matters and could have a material adverse effect on the financial results for the Evergy Companies.

Environmental, Social and Governance Risks:

The Evergy Companies are subject to risks relating to environmental, social and governance (ESG) matters that could adversely affect their reputation, business, financial position and results of operations.

The Evergy Companies are subject to a variety of risks, including reputational risk, associated with ESG issues. The public holds diverse and often conflicting views on ESG topics. The Evergy Companies have multiple stakeholders, including their shareholders, customers, associates, federal and state regulatory authorities and the communities in which they operate, and these stakeholders will often have differing priorities and expectations regarding ESG issues. If the Evergy Companies take action in conflict with one or another of those stakeholders' expectations, they could experience an increase in customer complaints, a loss of business or reputational harm. The Evergy Companies could also face negative publicity or reputational harm based on the identity of those with whom they choose to do business. Any adverse publicity in connection with ESG issues could damage their reputation, ability to attract new customers and retain employees, compete effectively and grow their business.

In addition, proxy advisory firms and certain institutional investors who manage investments in public companies are integrating ESG factors into their investment analysis. The consideration of ESG factors in making investment and voting decisions is relatively new and evolving. Accordingly, the frameworks and methods for assessing ESG policies are not fully developed, vary considerably among the investment community and will likely continue to evolve over time. Moreover, the subjective nature of methods used by various stakeholders to assess a company with respect to ESG criteria could result in erroneous perceptions or a misrepresentation of the Evergy Companies' actual ESG policies and practices. Organizations that provide ratings information to investors on ESG matters may also assign unfavorable ratings to the Evergy Companies. If the Evergy Companies fail to comply with specific ESG-related investor or stakeholder expectations and standards, or to provide the disclosure relating to ESG issues that any third parties may believe is necessary or appropriate (regardless of whether there is a legal requirement to do so), their reputation, business, financial position and/or results of operations could be negatively impacted.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

The Evergy Companies utilize an enterprise risk management framework to identify, evaluate and minimize risks. Risk management personnel meet annually with subject matter experts and each board member to identify and assess enterprise risk and also confer with each board member about the Evergy Companies' risk management profile. Evergy's Board has assigned primary oversight of enterprise risk management practices to the Audit Committee of the Evergy Board. At least annually, the Audit Committee reviews and discusses with management the Evergy Companies' enterprise risk management policies, processes, and frameworks, including conclusions reached regarding risk assessment and risk management.

Certain significant risks identified by the enterprise risk management process, such as cybersecurity, have a cross-functional team assigned to assess and manage the specific risk and may have oversight by a committee other than the Audit Committee. The Senior Vice President, Chief Technology Officer (CTO) and Senior Vice President, Chief Nuclear Officer (CNO), have overall accountability for the assessment, identification and management of cybersecurity risks on behalf of the Evergy Companies and Wolf Creek, respectively, subject to review by the Evergy Board and its committees. The CTO and CNO leverage the input and operations of the security management and operations team within each organizational structure. The security teams, comprised of cybersecurity professionals, lead the daily cyber risk mitigation efforts including cyber training of the workforce, threat monitoring, identification of potential cyber events and applicable compliance obligations. See Part I, Item 1, Business – Information about Evergy’s Executive Officers for a description of the CTO's and CNO's experience.

The Evergy Board has assigned primary oversight of cybersecurity risk to the Operations Committee of the Evergy Board. At each Operations Committee meeting, the CTO presents the Evergy Companies' cybersecurity metrics and scorecard performance; global, industry and Evergy-specific cybersecurity news; third-party assessments of the Evergy Companies' cybersecurity program; and industry benchmarking results. The Operations Committee meets regularly throughout the year and may meet more frequently or otherwise be informed of cybersecurity risk and incident information as needed. The CNO discusses with the Operations Committee risks specific to Wolf Creek, including cybersecurity risk. At least once each year, the Evergy Board receives a report from management on key business and compliance risks and related mitigation plans, and management discusses cybersecurity matters with the Evergy Board in connection with this report. The Evergy Companies also have a Security and Business Continuity Committee made up of internal security experts and several Evergy corporate officers. This committee meets bi-monthly to discuss relevant security and business continuity issues.

The Evergy Companies' risk mitigation function utilizes the National Institute of Standards and Technology Cybersecurity Framework (NIST CSF), the United States Department of Energy Cyber Capability Maturity Model (C2M2) standard and components of National Institute of Standards and Technology Risk Management Framework (NIST RMF) for a comprehensive, flexible and risk-based approach to managing risk from cybersecurity threats that integrates, security, privacy and cyber supply chain risk management activities. The NIST RMF considers effectiveness, efficiency and constraints due to applicable laws and regulations.

The Evergy Companies' cybersecurity organization uses the NIST CSF to model the security program. The Evergy Companies have implemented a layered defense model to protect against cyber intrusions and attacks. One layer of defense is Evergy's employees and their abilities to detect and respond to phishing attempts. Evergy conducts annual security awareness training and monthly phishing simulations. Employees that perform poorly in the phishing simulations are subject to additional training and disciplinary action. Other defense layers include firewalls at both the network and application layers, network segmentation, email scanning, multi-factor authentications, cloud security monitoring, in addition to other defensive layers. Several of the Evergy Companies' security tools employ AI and machine learning to enhance their respective capabilities. The Evergy Companies employ security practitioners with cybersecurity and information technology degrees and certifications and with extensive experience, with several holding federal government clearances. The Evergy Companies have a 24-hour Security Operations Center that monitors for security events and the Evergy Companies frequently engage with multiple third parties to analyze network traffic. Further, the Evergy Companies regularly and as needed engage cybersecurity consultants and third parties to assist with the identification, assessment and mitigation of cybersecurity risks and assessment of the Evergy Companies' risk mitigation practices. These services include, but are not limited to, the identification of vulnerabilities, penetration testing and assessment of the cybersecurity program to both validate effectiveness and also identify any areas for improvement.

Cybersecurity incidents are identified and mitigated by cybersecurity incident response plans that detail any actions to be taken when a cybersecurity incident occurs. The cybersecurity incident response plans define the organization, roles and responsibilities of the teams tasked with mitigating the impact of the cybersecurity incident. They define repeatable processes for responding to cybersecurity incidents; ensure communication to the CTO and CNO, as appropriate; minimize the impact to customer and business operations; coordinate response activities with external organizations; decrease the likelihood of reoccurrence and ensure regulatory reporting occurs, among other objectives. If warranted, the incident response plan may trigger the activation of the Crisis Management Team, a subset of officers who lead corporate functions and would collectively perform impact assessment and provide decision-making guidance as a component of the Crisis Management Plan within the Evergy Companies' business continuity and disaster recovery plans. Both the incident response plan and crisis management plan are practiced on an annual basis. In addition, the Evergy Companies share network traffic with federal and state agencies to assist with the identification and mitigation of cybersecurity incidents. The Evergy Companies participate in federal and industry information sharing programs, such as the Cybersecurity and Infrastructure Security Agency to assist in the exchange of cybersecurity-related information, analysis and incident mitigation techniques. On at least an annual basis, cross-functional teams and executive management participate in a simulated cybersecurity incident exercise and the Evergy Companies regularly simulate cybersecurity incidents, including phishing attacks, to assess organizational readiness. In addition to a bi-annual internal assessment, the NRC inspects Wolf Creek's processes to validate the effectiveness of the program to protect Wolf Creek from cybersecurity threats.

In addition, the Evergy Companies review many third parties with whom the Evergy Companies do business to understand and evaluate potential cybersecurity risks of engaging the third party and work with the third party to appropriately mitigate identified risks, as needed. Among other measures, certain third parties are required to have processes in place to mitigate risk that data would be compromised, to become aware of cybersecurity incidents and to promptly notify the Evergy Companies of any cybersecurity incidents. Generally, the Evergy Companies retain the right to perform an assessment, audit, examination or review of all controls in the third parties' environment to monitor compliance with applicable cybersecurity agreements. The Evergy Companies may decide not to move forward with a third party that does not meet security requirements.

While the Evergy Companies have a cybersecurity program designed to protect and preserve the integrity of their information systems, the Evergy Companies also maintain cybersecurity insurance to manage financial statement risk resulting from specific cyber-attacks. Although the Evergy Companies maintain cybersecurity insurance, there can be no guarantee that the Evergy Companies' insurance coverage limits will protect against any future claims or that such insurance proceeds will be paid in a timely manner.

The Evergy Companies have been subjected to attempted cyber-attacks from time to time, and will likely continue to be subject to such attempted attacks, but these prior attacks have not had a material impact on the Evergy Companies' operations or financial results to date. However, because technology is increasingly complex and cyber-attacks are increasingly sophisticated and more frequent through the use of such tools as AI, there can be no assurance that such incidents will not have a material adverse effect on the Evergy Companies in the future. See Item 1A. Risk Factors – Operational Risks for additional information.

ITEM 2. PROPERTIES

Generation Resources

Station	Unit No.	Location	Year Completed	Fuel	Unit Capability (MW) By Owner[a]					
					Evergy Kansas Central	Evergy Metro	Evergy Missouri West	Total Company Generation	Renewable Purchased Power	Total Generation and Renewable Purchased Power
Renewable Generation:										
Central Plains		Kansas	2009	Wind	99	—	—	99	—	99
Flat Ridge		Kansas	2009	Wind	50	—	—	50	44 (b)	94
Flat Ridge 3		Kansas	2021	Wind	—	—	—	—	128 (b)	128
Western Plains		Kansas	2017	Wind	281	—	—	281	—	281
Meridian Way		Kansas	2008	Wind	—	—	—	—	96 (b)	96
Ironwood		Kansas	2012	Wind	—	—	—	—	168 (b)	168
Post Rock		Kansas	2012	Wind	—	—	—	—	201 (b)	201
Cedar Bluff		Kansas	2015	Wind	—	—	—	—	199 (b)	199
Kay Wind		Oklahoma	2015	Wind	—	—	—	—	200 (b)	200
Soldier Creek		Kansas	2020	Wind	—	—	—	—	300 (b)	300
Ninnescah		Kansas	2016	Wind	—	—	—	—	208 (b)	208
Kingman 1		Kansas	2016	Wind	—	—	—	—	37 (b)	37
Kingman 2		Kansas	2016	Wind	—	—	—	—	103 (b)	103
Rolling Meadows		Kansas	2010	Landfill Gas	—	—	—	—	6 (b)	6
Hutchinson Solar		Kansas	2017	Solar	—	—	—	—	1 (b)	1
Ponderosa		Oklahoma	2020	Wind	—	—	—	—	178 (c)	178
Cimarron II		Kansas	2012	Wind	—	—	—	—	131 (d)	131
Cimarron Bend III		Kansas	2020	Wind	—	—	—	—	150 (e)	150
Spearville 1		Kansas	2006	Wind	—	101	—	101	—	101
Spearville 2		Kansas	2010	Wind	—	48	—	48	—	48
Spearville 3		Kansas	2012	Wind	—	—	—	—	101 (d)	101
Gray County		Kansas	2001	Wind	—	—	—	—	110 (f)	110
Ensign		Kansas	2012	Wind	—	—	—	—	99 (f)	99
Waverly		Kansas	2016	Wind	—	—	—	—	200 (d)	200
Slate Creek		Kansas	2015	Wind	—	—	—	—	150 (d)	150
Rock Creek		Missouri	2017	Wind	—	—	—	—	300 (g)	300
Osborn		Missouri	2016	Wind	—	—	—	—	201 (g)	201
Pratt		Kansas	2018	Wind	—	—	—	—	243 (g)	243
Greenwood Solar		Missouri	2016	Solar	—	—	3	3	—	3
Prairie Queen		Kansas	2019	Wind	—	—	—	—	200 (g)	200
St Joseph Landfill		Missouri	2012	Landfill Gas	—	—	2	2	—	2
Persimmon Creek		Oklahoma	2018	Wind	199	—	—	199	—	199
Hawthorn Solar		Missouri	2023	Solar	—	7	3	10	—	10
Total Renewable Generation:					629	156	8	793	3,754	4,547

Station	Unit No.		Location	Year Completed	Fuel	Unit Capability (MW) By Owner[a]					
						Evergy Kansas Central	Evergy Metro	Evergy Missouri West	Total Company Generation	Renewable Purchased Power	Total Generation and Renewable Purchased Power
Nuclear:											
Wolf Creek	1	(h)	Kansas	1985	Uranium	553	553	—	1,106	—	1,106
Total Nuclear:						553	553	—	1,106	—	1,106
Coal:											
Jeffrey Energy Center			Kansas								
Steam Turbines	1 - 3	(h)		1978, 1980 &1983	Coal	2,008	—	175	2,183	—	2,183
Lawrence Energy Center			Kansas								
Steam Turbines	4 & 5			1960, 1971	Coal	488	—	—	488	—	488
La Cygne			Kansas								
Steam Turbines	1 & 2	(h)(i)		1973, 1977	Coal	713	713	—	1,426	—	1,426
Iatan			Missouri								
Steam Turbines	1 & 2	(h)		1980, 2010	Coal	—	983	288	1,271	—	1,271
Hawthorn			Missouri								
Steam Turbines	5	(j)		1969	Coal	—	562	—	562	—	562
Total Coal:						3,209	2,258	463	5,930	—	5,930
Gas and Oil:											
Emporia Energy Center			Kansas								
Combustion Turbines	1 - 7			2008 - 2009	Natural Gas	654	—	—	654	—	654
Gordon Evans Energy Center			Kansas								
Combustion Turbines	1 - 3			2000 - 2001	Natural Gas	300	—	—	300	—	300
Hutchinson Energy Center			Kansas								
Combustion Turbines	1 - 3			1974	Natural Gas	167	—	—	167	—	167
	4			1975	Oil	70	—	—	70	—	70
Spring Creek Energy Center			Oklahoma								
Combustion Turbines	1 - 4			2001	Natural Gas	294	—	—	294	—	294
State Line			Missouri								
Combined Cycle	1 - 3	(h)		2001	Natural Gas	211	—	—	211	—	211
Hawthorn			Missouri								
Combined Cycle	6 & 9			2000	Natural Gas	—	242	—	242	—	242
Combustion Turbines	7 & 8			2000	Natural Gas	—	157	—	157	—	157
West Gardner			Kansas								
Combustion Turbines	1 - 4			2003	Natural Gas	—	315	—	315	—	315

Station	Unit No.	Location	Year Completed	Fuel	Unit Capability (MW) By Owner[a] Evergy Kansas Central	Evergy Metro	Evergy Missouri West	Total Company Generation	Renewable Purchased Power	Total Generation and Renewable Purchased Power
Gas and Oil (continued):										
Osawatomie		Kansas								
Combustion Turbines	1		2003	Natural Gas	—	77	—	77	—	77
Ralph Green		Missouri								
Combustion Turbines	3		1981	Natural Gas	—	—	66	66	—	66
Nevada		Missouri								
Combustion Turbines	1		1974	Oil	—	—	16	16	—	16
Lake Road		Missouri								
Combustion Turbines	1 - 3		1951, 1958 & 1962	Natural Gas	—	—	49	49	—	49
	5 - 7		1974, 1989 & 1990	Oil	—	—	106	106	—	106
Steam Turbines	4		1967	Natural Gas	—	—	95	95	—	95
Northeast		Missouri								
Combustion Turbines	11 - 18		1972 - 1977	Oil	—	394	—	394	—	394
South Harper		Missouri								
Combustion Turbines	1 - 3		2005	Natural Gas	—	—	321	321	—	321
Greenwood Energy Center		Missouri								
Combustion Turbines	1 - 4		1975 - 1979	Natural Gas	—	—	250	250	—	250
Crossroads Energy Center		Mississippi								
Combustion Turbines	1 - 4		2002	Natural Gas	—	—	300	300	—	300
Dogwood Energy Center		Missouri								
Combined Cycle	1 - 3 (h)		2002	Natural Gas	—	—	145	145	—	145
Total Gas and Oil					1,696	1,185	1,348	4,229	—	4,229
Total					6,087	4,152	1,819	12,058	3,754	15,812

[a] Capability (except for wind generating facilities) represents estimated 2026 net generating capacity. Capability for wind generating facilities represents the nameplate capacity. Due to the intermittent nature of wind generation, these facilities are associated with a total of 1,515 MWs of accredited generating capacity pursuant to SPP reliability standards.
[b] Evergy Kansas Central renewable power purchase agreement.
[c] Evergy Kansas Central and Evergy Metro renewable power purchase agreement.
[d] Evergy Metro renewable power purchase agreement.
[e] Evergy Kansas Central and Evergy Missouri West renewable power purchase agreement.
[f] Evergy Missouri West renewable power purchase agreement.
[g] Evergy Metro and Evergy Missouri West renewable power purchase agreement.
[h] Share of a jointly owned unit.
[i] In 1987, Evergy Kansas South entered into a sale-leaseback transaction involving its 50% interest in the La Cygne Unit 2. Evergy and Evergy Kansas Central consolidate the leasing entity as a variable interest entity (VIE). See Note 19 to the consolidated financial statements for more information.
[j] Although the plant was completed in 1969, a new boiler, air quality control equipment and an uprated turbine were placed in service at the Hawthorn Generating Station in 2001.

Transmission and Distribution Resources
Evergy's electric transmission system interconnects with systems of other utilities for reliability and to permit wholesale transactions with other electricity suppliers. Evergy has approximately 10,200 circuit miles of transmission lines, 44,600 circuit miles of overhead distribution lines and 16,700 circuit miles of underground distribution lines in Missouri and Kansas. Evergy has all material franchise rights necessary to sell electricity within its retail service territory. Evergy's transmission and distribution systems are routinely monitored for adequacy to meet customer needs. Management believes the current system has adequate capacity to serve customers.

General
Evergy's generating plants are located on property owned (or co-owned) by the Evergy Companies, except for certain facilities that are located on easements or are contractually controlled. Evergy's headquarters, service centers, electric substations and a portion of its transmission and distribution systems are located on property owned or leased by Evergy. Evergy's transmission and distribution systems are for the most part located above or underneath highways, streets, other public places or property owned by others. Evergy believes that it has satisfactory rights to use those places or properties in the form of permits, grants, easements, licenses or franchise rights; however, it has not necessarily undertaken efforts to examine the underlying title to the land upon which the rights rest.

Substantially all of the fixed property and franchises of the Evergy Companies, which consist principally of electric generating stations, electric transmission and distribution lines and systems, and buildings (subject to exceptions, reservations and releases), are subject to mortgage indentures pursuant to which bonds have been issued and are outstanding. See Note 12 to the consolidated financial statements for more information.

ITEM 3. LEGAL PROCEEDINGS

The Evergy Companies are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Notes 4 and 15 to the consolidated financial statements. Such information is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

EVERGY, INC.

Evergy's common stock is listed on the Nasdaq Stock Market LLC under the symbol "EVRG." At February 11, 2026, Evergy's common stock was held by 14,484 shareholders of record.

Purchases of Equity Securities

The following table provides information regarding purchases by Evergy of its equity securities that are registered pursuant to Section 12 of the Exchange Act during the three months ended December 31, 2025.

Issuer Purchases of Equity Securities				
Month	**Total Number of Shares (or Units) Purchased[(a)]**	**Average Price Paid per Share (or Unit)**	**Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs**	**Maximum Number of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs**
October 1 - 31	6,291	$76.35	—	—
November 1 - 30	—	—	—	—
December 1 - 31	2,520	$75.41	—	—
Total	8,811	$76.08	—	—

[(a)] Represents shares Evergy purchased for withholding taxes related to the vesting of restricted stock or restricted stock units.

Dividend Restrictions

For information regarding dividend restrictions, see Note 18 to the consolidated financial statements.

ITEM 6. RESERVED

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following combined MD&A should be read in conjunction with the consolidated financial statements and accompanying notes in this combined annual report on Form 10-K. None of the registrants make any representation as to information related solely to Evergy, Evergy Kansas Central or Evergy Metro other than itself. The following MD&A generally discusses 2025 and 2024 items and year-to-year comparisons between 2025 and 2024. Discussions of 2023 items and year-to-year comparisons between 2024 and 2023 can be found in MD&A in Part II, Item 7, of the Evergy Companies' combined annual report on Form 10-K for the fiscal year ended December 31, 2024 and are incorporated herein by reference.

EVERGY, INC.

EXECUTIVE SUMMARY

Evergy is a public utility holding company incorporated in 2017 and headquartered in Kansas City, Missouri. Evergy operates primarily through the following wholly-owned direct subsidiaries listed below.

- Evergy Kansas Central is an integrated, regulated electric utility that provides electricity to customers in the state of Kansas. Evergy Kansas Central has one active wholly-owned subsidiary with significant operations, Evergy Kansas South.
- Evergy Metro is an integrated, regulated electric utility that provides electricity to customers in the states of Missouri and Kansas.
- Evergy Missouri West is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri.
- Evergy Transmission Company owns 13.5% of Transource with the remaining 86.5% owned by AEP Transmission Holding Company, LLC, a subsidiary of AEP. Transource is focused on the development of competitive electric transmission projects. Evergy Transmission Company accounts for its investment in Transource under the equity method.

Evergy Kansas Central also owns a 50% interest in Prairie Wind, which is a joint venture between Evergy Kansas Central and subsidiaries of AEP and Berkshire Hathaway Energy Company. Prairie Wind owns a 108-mile, 345 kV double-circuit transmission line that provides transmission service in the SPP. Evergy Kansas Central accounts for its investment in Prairie Wind under the equity method.

Evergy Kansas Central, Evergy Kansas South, Evergy Metro and Evergy Missouri West conduct business in their respective service territories using the name Evergy. Collectively, the Evergy Companies have approximately 15,800 MWs of owned generating capacity and renewable power purchase agreements and engage in the generation, transmission, distribution and sale of electricity to approximately 1.7 million customers in the states of Kansas and Missouri. The Evergy Companies assess financial performance and allocate resources on a consolidated basis (i.e., operate in one segment).

Strategy

Evergy expects to continue operating its integrated utilities within the currently existing regulatory frameworks and is focused on enabling economic development across all of its service territories to strengthen the communities it serves and meet existing and future customer electricity demand growth through the continued evolution of its generation, transmission and distribution systems. Evergy will remain focused on consistently delivering on its affordability, reliability and sustainability objectives and delivering competitive long-term returns to shareholders, including growth in earnings per share and targeting a 50%-60% dividend payout ratio. The core tenets of Evergy's strategy are as follows:

- Affordability – maintaining affordable rates while investing in infrastructure and technology to support growth and prosperity;
- Reliability – targeting top-tier performance in reliability, customer service and generation; and
- Sustainability – advancing an "all-of-the-above" generation portfolio.

Significant elements of Evergy's plan to achieve its strategic objectives include:

- across the board, maintaining excellence in day-to-day operations. Safety-first, cost efficiency, infrastructure investment, new technology deployment and process improvement are crucial components of Evergy's vision and enable improvement in the important metrics of reliability, customer satisfaction and cost performance to the sustainable benefit of customers;

- fostering economic development in Kansas and Missouri by supporting the attraction of new businesses and large load customers while ensuring protections for existing customers through key safeguards included in the LLPS rate plans;
- targeting approximately $21.6 billion of expected capital investments through 2030 including new generation of approximately $9.3 billion which is expected to be primarily natural gas, renewable generation and battery storage capacity in support of historic economic development opportunities in Kansas and Missouri. See "Liquidity and Capital Resources - Capital Expenditures," for further information regarding Evergy's projected capital expenditures through 2030;
- adding new highly-efficient natural gas generation resources, renewable generation and storage to support economic growth in the region and to enable the ongoing modernization of Evergy's generation fleet, consistent with Evergy's "all-of-the-above" strategy to leverage a diverse set of fuel sources. The trajectory and timing of achieving emissions reductions relative to 2005 levels and Evergy's long-term emissions reductions goal are expected to be dependent on enabling technology developments, trends in total demand for electricity, the reliability of the power grid, availability of transmission capacity and supportive energy policies and regulations, among other external factors. See "Modernizing and Expanding Evergy's Generation Fleet" in Part I, Item 1. Business, for additional information; and
- accessing debt and equity capital markets to support the Evergy Companies' capital investment plans.

See "Cautionary Statements Regarding Certain Forward-Looking Information" and Part I, Item 1A. Risk Factors, for additional information.

Evergy Metro's 2026 Rate Case Proceeding
In February 2026, Evergy Metro filed an application with the MPSC to request an increase to its retail revenues of approximately $140 million. Evergy Metro's request reflected a return on equity of 10.5% (with a capital structure composed of 52% equity) and increases related to the recovery of infrastructure investments made to improve reliability and enhance customer service and the update of expenses to current levels of spend. New rates are expected to be effective in January 2027.

Evergy Kansas Central's 2025 Rate Case Proceeding
In January 2025, Evergy Kansas Central filed an application with the KCC to request an increase to its retail revenues of approximately $196 million. Evergy Kansas Central's request reflected a return on equity of 10.5% (with a capital structure composed of 52% equity) and increases related to the recovery of infrastructure investments made to improve reliability and enhance customer service and the update of expenses to current levels of spend.

In July 2025, Evergy Kansas Central, the KCC staff and other intervenors in the case reached a unanimous settlement agreement to settle all outstanding issues in the case. The unanimous settlement provides for an increase to retail revenues of $128.0 million after rebasing property tax expense and not including costs recoverable through KCC-approved riders for Evergy Kansas Central. In September 2025, the KCC approved the unanimous settlement agreement and new rates took effect in October 2025. See Note 4 to the consolidated financial statements for additional information.

Large Load Power Service Rate Plans and Executed Large Customer Agreements
In February 2025, Evergy Kansas Central and Evergy Metro filed an application with the KCC and Evergy Metro and Evergy Missouri West filed an application with the MPSC seeking expedited approval of new comprehensive LLPS rate plans. In August 2025, Evergy Kansas Central, Evergy Metro, the KCC staff and other intervenors reached a unanimous settlement agreement for the LLPS rate plan which the KCC approved in November 2025. In September 2025, Evergy Metro, Evergy Missouri West and other intervenors agreed to a non-unanimous global stipulation and agreement for the LLPS rate plan which the MPSC approved in November 2025.

The LLPS rate plans are designed to establish a tariff framework for large load customers while including safeguards for existing customers to ensure that new large customers pay their cost of service and help defray costs that might be experienced by other customers. The provisions in the LLPS rate plans in both Kansas and Missouri apply to new or existing customers adding load in excess of 75 MWs. These plans have a term length of 12 years after a period of up to 5-years of transitional load. The minimum monthly bill requirement is set based on 80% of the customers' expected capacity demand and is applied to all demand-related bill elements and riders. Termination fees will be calculated as the minimum monthly bill requirement multiplied by the remaining months in the contract. New large load customers will also be required to post collateral equal to two years of minimum monthly bills at the time of signing the agreement, subject to established discounts based on creditworthiness. The Evergy Companies, at their discretion, may require additional collateral based on assessment of the overall creditworthiness of the counterparty.

In February 2026, the Evergy Companies signed electric service agreements (ESAs) with multiple large load customers to serve data centers with a projected peak steady state load of approximately 1,900 MWs. The ESAs relate to two new projects and the expansion of two separate projects previously announced. The ESAs' terms reflect the applicable provisions of the Evergy Companies' LLPS rate plans and the service of these large load customers, inclusive of a 5-year transitional load period, is expected to begin at dates ranging from 2026 to 2028.

Federal Tax Reform
In July 2025, the OBBBA was signed into law by President Trump. The OBBBA contains a wide variety of tax reforms affecting businesses, including changes to clean energy production tax credits, which could impact the Evergy Companies' long-term generation resource planning. The Evergy Companies do not expect a material impact to their operations and consolidated financial results.

Missouri Legislation
In April 2025, Missouri Senate Bill (SB) 4 was signed into law by the Governor of Missouri. Most notably, SB 4 establishes new mechanisms for Missouri electric utilities to recover the costs associated with the construction of new natural gas-fired generating units. The utilities will be able to include certain costs of construction work in progress (CWIP) in rate base. The inclusion of CWIP will be in lieu of allowance for funds used during construction (AFUDC) applicable to the construction of the new natural gas-fired generating units. The MPSC will determine the amount of CWIP that may be included in rate base. Additionally, amounts collected arising from the inclusion of CWIP in rate base are subject to refund under certain circumstances. These provisions are scheduled to expire at the end of 2035.

Additionally, the law extends Missouri's existing PISA provisions to include certain natural gas-fired generating units as qualifying electric plant and extends the sunset date of these provisions through the end of 2035. These provisions allow electric utilities to defer to a regulatory asset for recovery in a subsequent general rate case 85% of depreciation expense and the associated return on investment for qualifying electric plant rate base additions for assets placed in-service between general rate cases.

Kansas Legislation
In April 2025, Kansas House Bill (HB) 2107 was signed into law by the Governor of Kansas. Most notably, HB 2107 establishes a two-year statute of limitations for wildfire-related claims against a Kansas electric public utility and a $5.0 million limit for punitive damages awarded under a fire claim. The law also requires the plaintiff to establish the burden of proof for fire claims by a preponderance of evidence.

Natural Gas Plant Investments
The Evergy Companies use IRPs, detailed analyses that estimate factors that influence the future supply and demand for electricity, to inform the manner in which they supply electricity. The most recent IRPs incorporate the latest SPP resource adequacy requirements and anticipated load growth. Based on these and other factors, the IRPs indicated the addition of new supply side resources, including combined and simple cycle natural gas plants, would be needed.

In October 2024, Evergy announced its plan to construct two combined-cycle natural gas plants located in Kansas. Evergy Kansas Central and Evergy Missouri West will jointly-own each plant and expect each plant to have an initial generating capacity of approximately 705 MWs. The first plant, a combined cycle gas turbine (CCGT) facility located in Sumner County, is expected to begin operations by spring of 2029 and the second plant, a CCGT facility located in Reno County, is expected to begin operations by spring of 2030.

Additionally, Evergy Missouri West plans to construct a 440 MW simple-cycle natural gas plant located in Missouri. The plant is expected to begin operations in 2030.

In 2024, Evergy Kansas Central and Evergy Missouri West requested predetermination from the KCC and a Certificate of Convenience and Necessity (CCN) from the MPSC, respectively, for their planned natural gas investments. In July 2025, the KCC approved a non-unanimous partial settlement agreement regarding Evergy Kansas Central's investments in its planned natural gas plants. In July 2025, the MPSC approved a non-unanimous stipulation and agreement regarding Evergy Missouri West's investments in its planned natural gas plants. See "Applications for Predetermination" and "Requests for Certificate of Convenience and Necessity" in Note 4 to the consolidated financial statements for additional information regarding Evergy Kansas Central's and Evergy Missouri West's applications for predetermination and a CCN for their investments in these natural gas plants.

Renewable Plant Investments

Evergy Kansas Central intends to construct and own an approximately 159 MW solar generation facility, to be located in Douglas County Kansas, called Kansas Sky. In July 2024, a lawsuit was filed in the District Court of Douglas County, *Grant Township, et al. v. Board of County Commissioners*, requesting the court to overturn Douglas County's approval of the application to construct the solar generation facility. Due to the ongoing litigation, including the court's granting of an emergency injunction in December 2024 which temporarily prohibits the construction of the solar generation facility, Evergy Kansas Central is not able to estimate when the solar generation facility will begin operations. In July 2025, the KCC approved a unanimous partial settlement agreement for the Kansas Sky solar investment. See "Applications for Predetermination" in Note 4 to the consolidated financial statements for additional information regarding Evergy Kansas Central's application for predetermination for its investment in this renewable generating plant.

In 2024, Evergy Missouri West entered into agreements to own two solar generation facilities currently under development. The first facility, to be called Sunflower Sky, is a solar generation facility to be located in Kansas with an expected generating capacity of approximately 65 MWs. In September 2025, Evergy Missouri West acquired the Sunflower Sky solar facility assets from the developer and will complete construction of the facility. The second facility, to be called Foxtrot, is a solar generation facility to be located in Missouri with an expected generating capacity of approximately 100 MWs. In November 2025, Evergy Missouri West acquired the Foxtrot solar facility assets from the developer and will complete construction of the facility. The solar generation facilities are expected to begin operations by summer of 2027. In July 2025, the MPSC approved a unanimous stipulation and agreement regarding Evergy Missouri West's planned investments in the solar generation facilities. See "Requests for Certificate of Convenience and Necessity" in Note 4 to the consolidated financial statements for information regarding Evergy Missouri West's application for a CCN for its investment in these renewable generating plants.

Convertible Note Repurchases

In January and February 2026, Evergy, Inc. repurchased $244.1 million aggregate principal amount of its $1.4 billion aggregate principal amount of 4.50% Convertible Notes (Convertible Notes), under separate, privately negotiated repurchase agreements with certain holders of its Convertible Notes, for a total repurchase cost (excluding accrued and unpaid interest) of $308.6 million. After these January and February 2026 repurchases, $1,155.9 million aggregate principal amount of Convertible Notes remain outstanding. See "Convertible Notes" in Note 12 to the consolidated financial statements for additional information regarding Evergy, Inc.'s repurchase of Convertible Notes.

Regulatory Proceedings

See Note 4 to the consolidated financial statements for information regarding other regulatory proceedings.

Wolf Creek Refueling Outage
Wolf Creek's most recent refueling outage began in October 2025 and the unit returned to service in November 2025. Wolf Creek's next refueling outage is planned to begin in the spring of 2027.

Earnings Overview
The following table summarizes Evergy's net income and diluted earnings per share (EPS).

	2025	Change	2024
	(millions, except per share amounts)		
Net income attributable to Evergy, Inc.	$ 855.6	$ (17.9)	$ 873.5
Earnings per common share, diluted	3.66	(0.13)	3.79

Net income attributable to Evergy, Inc. decreased in 2025, compared to the same period in 2024, primarily due to higher operating and maintenance, depreciation and interest expense, losses from non-regulated investments in early-stage clean energy and energy solution companies and lower proceeds from corporate-owned life insurance (COLI); partially offset by new Evergy Missouri West and Evergy Kansas Central retail rates effective in January and October 2025, respectively, and higher transmission revenues.

Diluted EPS decreased in 2025, compared to the same period in 2024, primarily due to the decrease in net income attributable to Evergy, Inc. discussed above in addition to a $0.05 per share decrease primarily due to dilution from Evergy's convertible notes.

For additional information regarding the change in net income, refer to the Evergy Results of Operations section within this MD&A.

Non-GAAP Measures
Evergy Utility Gross Margin (non-GAAP)
Utility gross margin (non-GAAP) is a financial measure that is not calculated in accordance with GAAP. Utility gross margin (non-GAAP), as used by the Evergy Companies, is defined as operating revenues less fuel and purchased power costs and amounts billed by the SPP for network transmission costs. Expenses for fuel and purchased power costs, offset by wholesale sales margin, are subject to recovery through cost adjustment mechanisms. As a result, changes in fuel and purchased power costs are offset in operating revenues with minimal impact on net income. In addition, SPP network transmission costs fluctuate primarily due to investments by SPP members for upgrades to the transmission grid within the SPP RTO. As with fuel and purchased power costs, changes in SPP network transmission costs are mostly reflected in the prices charged to customers with minimal impact on net income. The Evergy Companies' definition of utility gross margin (non-GAAP) may differ from similar terms used by other companies.

Utility gross margin (non-GAAP) is intended to aid an investor's overall understanding of results. Management believes that utility gross margin (non-GAAP) provides a meaningful basis for evaluating the Evergy Companies' operations across periods because utility gross margin (non-GAAP) excludes the revenue effect of fluctuations in fuel and purchased power costs and SPP network transmission costs. Utility gross margin (non-GAAP) is used internally to measure performance against budget and in reports for management and the Evergy Board. Utility gross margin (non-GAAP) should be viewed as a supplement to, and not a substitute for, gross margin, which is the most directly comparable financial measure prepared in accordance with GAAP. Gross margin under GAAP is defined as the excess of sales over cost of goods sold.

Utility gross margin (non-GAAP) differs from the GAAP definition of gross margin due to the exclusion of operating and maintenance expenses determined to be directly attributable to revenue-producing activities, depreciation and amortization and taxes other than income tax. See the Evergy Companies' Results of Operations for a reconciliation of utility gross margin (non-GAAP) to gross margin, the most comparable GAAP measure.

Adjusted Earnings (non-GAAP) and Adjusted EPS (non-GAAP)

Management believes that adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP) are representative measures of Evergy's recurring earnings, assist in the comparability of results and are consistent with how management reviews performance.

Evergy's adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP) for 2025, were $893.8 million or $3.83 per share. For 2024, Evergy's adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP) were $877.9 million or $3.81 per share.

In addition to net income attributable to Evergy, Inc. and diluted EPS, Evergy's management uses adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP) to evaluate earnings and EPS without:

i. the realized losses, unrealized losses and impairment losses from non-regulated investments in early-stage clean energy and energy solution companies and costs related to the disposal of these investments;

ii. the mark-to-market impacts of economic hedges related to Evergy Kansas Central's 8% ownership share of Jeffrey Energy Center (JEC); and

iii. the costs incurred in the fourth quarter 2024 resulting from the realignment of the executive operations corporate structure.

Adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP) are intended to aid an investor's overall understanding of results. Management believes that adjusted earnings (non-GAAP) provides a meaningful basis for evaluating Evergy's operations across periods because it excludes certain items that management does not believe are indicative of Evergy's ongoing performance or that can create period to period earnings volatility.

Adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP) are used internally to measure performance against budget and in reports for management and the Evergy Board. Adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP) are financial measures that are not calculated in accordance with GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income attributable to Evergy, Inc. and diluted EPS as determined in accordance with GAAP and adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP), respectively.

	Earnings (Loss)	Earnings (Loss) per Diluted Share	Earnings (Loss)	Earnings (Loss) per Diluted Share
	2025		2024	
	(millions, except per share amounts)			
Net income attributable to Evergy, Inc.	$ 855.6	$ 3.66	$ 873.5	$ 3.79
Non-GAAP reconciling items:				
Losses from investments in early-stage clean energy and energy solution companies, pre-tax[(a)]	49.0	0.22	—	—
Mark-to-market impact of JEC economic hedges, pre-tax[(b)]	—	—	2.6	0.01
Executive operations team realignment, pre-tax[(c)]	—	—	2.5	0.01
Income tax benefit[(d)]	(10.8)	(0.05)	(0.7)	—
Adjusted earnings (non-GAAP)	$ 893.8	$ 3.83	$ 877.9	$ 3.81

[(a)] Reflects realized losses, unrealized losses and impairment losses of $48.7 million from non-regulated investments in early-stage clean energy and energy solution companies that are included in investment earnings (loss) on the consolidated statements of comprehensive

income and $0.3 million of costs related to the disposal of these investments that are included in operating and maintenance expense on the consolidated statements of comprehensive income. Evergy has initiated a process to dispose of these investments.

(b) Reflects mark-to-market gains or losses related to forward contracts for natural gas and electricity entered into as economic hedges against fuel price volatility related to Evergy Kansas Central's 8% ownership share of JEC that are included in operating revenues on the consolidated statements of comprehensive income.

(c) Reflects costs incurred associated with the realignment of the executive operations corporate structure that are included in operating and maintenance expense and taxes other than income tax on the consolidated statements of comprehensive income.

(d) Reflects an income tax effect calculated at a statutory rate of approximately 22%, with the exception of certain non-deductible items.

ENVIRONMENTAL MATTERS

See Note 15 to the consolidated financial statements for information regarding environmental matters.

RELATED PARTY TRANSACTIONS

See Note 17 to the consolidated financial statements for information regarding related party transactions.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures. 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 used, could have a material impact on Evergy's results of operations and financial position. Management has identified the following accounting policies as critical to the understanding of Evergy's results of operations and financial position. Management has discussed the development and selection of these critical accounting policies with the Audit Committee of the Evergy Board.

Pensions

Evergy incurs significant costs in providing non-contributory defined pension benefits. The costs are measured using actuarial valuations that are dependent upon numerous factors derived from actual plan experience and assumptions of future plan experience.

Pension costs are impacted by actual employee demographics (including age, life expectancies, compensation levels and employment periods), earnings on plan assets, the level of contributions made to the plan, and plan amendments. In addition, pension costs are also affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

The assumed rate of return on plan assets was developed based on the weighted-average of long-term returns forecast for the expected portfolio mix of investments held by the plan. The assumed discount rate was selected based on the prevailing market rate of fixed income debt instruments with maturities matching the expected timing of the benefit obligation. These assumptions, updated annually at the measurement date, are based on management's best estimates and judgment; however, material changes may occur if these assumptions differ from actual events. See Note 9 to the consolidated financial statements for information regarding the assumptions used to determine benefit obligations and net costs.

The following table reflects the sensitivities associated with a 0.5% increase or a 0.5% decrease in key actuarial assumptions for Evergy's qualified pension plans. Each sensitivity reflects the impact of the change based on a change in that assumption only.

Actuarial assumption	Change in Assumption	Impact on Projected Benefit Obligation	Impact on 2026 Pension Expense
		(millions)	
Discount rate	0.5 % increase	$ (95.6)	$ (10.0)
Rate of return on plan assets	0.5 % increase	N/A	(6.7)
Rate of compensation	0.5 % increase	22.2	4.7
Discount rate	0.5 % decrease	105.9	11.0
Rate of return on plan assets	0.5 % decrease	N/A	6.7
Rate of compensation	0.5 % decrease	(20.9)	(4.5)

Pension expense for Evergy Kansas Central, Evergy Metro and Evergy Missouri West is recorded in accordance with rate orders from the KCC and MPSC. The orders allow the difference between pension costs under GAAP and pension costs for ratemaking to be recorded as a regulatory asset or liability with future ratemaking recovery or refunds, as appropriate.

In 2025, Evergy's pension expense was $42.5 million under GAAP and $54.3 million for ratemaking. The impact on 2026 pension expense in the table above reflects the impact on GAAP pension costs. Under the Evergy Companies' rate agreements, any increase or decrease in GAAP pension expense is deferred to a regulatory asset or liability for future ratemaking treatment. See Note 9 to the consolidated financial statements for additional information regarding the accounting for pensions.

Market conditions and interest rates significantly affect the future assets and liabilities of the plan. It is difficult to predict future pension costs, changes in pension liability and cash funding requirements due to the inherent uncertainty of market conditions.

Revenue Recognition

Evergy recognizes revenue on the sale of electricity to customers over time as the service is provided in the amount it has the right to invoice. Revenues recorded include electric services provided but not yet billed by Evergy. Unbilled revenues are recorded for kWh usage in the period following the customers' billing cycle to the end of the month. This estimate is based on net system kWh usage less actual billed kWhs. Evergy's estimated unbilled kWhs are allocated and priced by regulatory jurisdiction across the rate classes based on actual billing rates. Evergy's unbilled revenue estimate is affected by factors including fluctuations in energy demand, weather, line losses and changes in the composition of customer classes. See Note 3 to the consolidated financial statements for the balance of unbilled receivables for Evergy as of December 31, 2025 and 2024.

Regulatory Assets and Liabilities

Evergy has recorded assets and liabilities on its consolidated balance sheets resulting from the effects of the ratemaking process, which would not otherwise be recorded under GAAP. Regulatory assets represent incurred costs that are probable of recovery from future revenues. Regulatory liabilities represent future reductions in revenues or refunds to customers.

Management regularly assesses whether regulatory assets and liabilities are probable of future recovery or refund by considering factors such as decisions by the MPSC, KCC or FERC in Evergy's rate case filings; decisions in other regulatory proceedings, including decisions related to other companies that establish precedent on matters applicable to Evergy; and changes in laws and regulations. If recovery or refund of regulatory assets or liabilities is not approved by regulators or is no longer deemed probable, these regulatory assets or liabilities are recognized in the current period results of operations. Evergy's continued ability to meet the criteria for recording regulatory

assets and liabilities may be affected in the future by restructuring and deregulation in the electric industry or changes in accounting rules. In the event that the criteria no longer applied to all or a portion of Evergy's operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory recovery mechanism were provided. Additionally, these factors could result in an impairment on utility plant assets. See Note 4 to the consolidated financial statements for additional information.

Impairments of Assets and Goodwill
Long-lived assets are required to be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable as prescribed under GAAP.

Accounting rules require goodwill to be tested for impairment annually and when an event occurs indicating the possibility that an impairment exists. The goodwill impairment test consists of comparing the fair value of a reporting unit to its carrying amount, including goodwill, to identify potential impairment. In the event that the carrying amount exceeds the fair value of the reporting unit, an impairment loss is recognized for the difference between the carrying amount of the reporting unit and its fair value. Evergy's consolidated operations are considered one reporting unit for assessment of impairment, as management assesses financial performance and allocates resources on a consolidated basis. The annual impairment test for the $2,336.6 million of goodwill from the merger that created Evergy was conducted as of May 1, 2025. The fair value of the reporting unit substantially exceeded the carrying amount, including goodwill. As a result, there was no impairment of goodwill.

The determination of fair value for the reporting unit consisted of two valuation techniques: an income approach consisting of a discounted cash flow analysis and a market approach consisting of a determination of reporting unit invested capital using a market multiple derived from the historical earnings before interest, income taxes, depreciation and amortization and market prices of the stock of peer companies. The results of the two techniques were evaluated and weighted to determine a point within the range that management considered representative of fair value for the reporting unit, which involves a significant amount of management judgment.

The discounted cash flow analysis is most significantly impacted by two assumptions: estimated future cash flows and the discount rate applied to those cash flows. Management determines the appropriate discount rate to be based on the reporting unit's weighted average cost of capital (WACC). The WACC takes into account both the return on equity authorized by the KCC and MPSC and after-tax cost of debt. Estimated future cash flows are based on Evergy's internal business plan, which assumes the occurrence of certain events in the future, such as the outcome of future rate filings, future approved rates of return on equity, anticipated returns of and earnings on future capital investments, continued recovery of cost of service and the renewal of certain contracts. Management also makes assumptions regarding the run rate of operations, maintenance and general and administrative costs based on the expected outcome of the aforementioned events. Should the actual outcome of some or all of these assumptions differ significantly from the current assumptions, revisions to current cash flow assumptions could cause the fair value of the Evergy reporting unit under the income approach to be significantly different in future periods and could result in a future impairment charge to goodwill.

The market approach analysis is most significantly impacted by management's selection of relevant peer companies as well as the determination of an appropriate control premium to be added to the calculated invested capital of the reporting unit, as control premiums associated with a controlling interest are not reflected in the quoted market price of a single share of stock. Management determines an appropriate control premium by using an average of control premiums for recent acquisitions in the industry. Changes in results of peer companies, selection of different peer companies and future acquisitions with significantly different control premiums could result in a significantly different fair value of the Evergy reporting unit.

Income Taxes
Income taxes are accounted for using the asset/liability approach. Deferred tax assets and liabilities are determined based on the temporary differences between the financial reporting and tax bases of assets and liabilities, applying enacted statutory tax rates in effect for the year in which the differences are expected to reverse. Deferred investment tax credits are amortized ratably over the life of the related property. Deferred tax assets are also recorded for NOLs, capital losses and tax credit carryforwards. Evergy is required to estimate the amount of taxes

payable or refundable for the current year and the deferred tax liabilities and assets for future tax consequences of events reflected in Evergy's consolidated financial statements or tax returns. Actual results could differ from these estimates for a variety of reasons including changes in income tax laws, enacted tax rates and results of audits by taxing authorities. This process also requires management to make assessments regarding the timing and probability of the ultimate tax impact from which actual results may differ. Evergy records valuation allowances on deferred tax assets if it is determined that it is more likely than not that the asset will not be realized. See Note 20 to the consolidated financial statements for additional information.

Asset Retirement Obligations
Evergy has recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. Concurrent with the recognition of the liability, the estimated cost of the ARO incurred at the time the related long-lived assets were either acquired, placed in service or when regulations establishing the obligation became effective is also recorded to property, plant and equipment, net, on the consolidated balance sheets. The recording of AROs for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset or an offset to a regulatory liability.

Evergy initially records AROs at fair value for the estimated costs to decommission Wolf Creek (94% indirect share), retire wind generating facilities, dispose of asbestos insulating material at its power plants, remediate ash disposal ponds and close ash landfills, among other items. AROs refer to legal obligations to perform an asset retirement activity in which the timing and/or method of settlement may be conditional on a future event that may or may not be within the control of the entity. In determining Evergy's AROs, assumptions are made regarding probable future disposal costs and the timing of their occurrence. The results of these assumptions are discounted using credit-adjusted risk-free rates (CARFR). The CARFR is determined as the current U.S. Treasury bonds rates corresponding to the period of expected settlement activities and is adjusted for the associated bond rates Evergy would be charged to borrow for the specific time period. Any change in these assumptions could have a significant impact on Evergy's AROs reflected on its consolidated balance sheets.

As of December 31, 2025 and 2024, Evergy had recorded AROs of $1,342.3 million and $1,297.0 million, respectively. See Note 6 to the consolidated financial statements for more information regarding Evergy's AROs.

EVERGY RESULTS OF OPERATIONS

Evergy's results of operations and financial position are affected by a variety of factors including rate regulation, fuel costs, weather, level of capital investment, customer behavior and demand, the economy and competitive forces.

Substantially all of Evergy's revenues are subject to state or federal regulation. This regulation has a significant impact on the price the Evergy Companies charge for electric service. Evergy's results of operations and financial position are affected by its ability to align overall spending, both operating and capital, within the frameworks established by its regulators and to mitigate the impacts of inflationary pressures.

Wholesale revenues are impacted by, among other factors, demand, cost and availability of fuel and purchased power, price volatility, available generation capacity, transmission availability and weather.

The Evergy Companies use coal, uranium and gas for the generation of electricity for their customers and also purchase power through renewable power purchase agreements or on the open market. The prices for fuel used in generation or the market price of power purchases can fluctuate significantly due to a variety of factors including supply, demand, weather and the broader economic environment. Evergy Kansas Central, Evergy Metro and Evergy Missouri West have fuel recovery mechanisms in their Kansas and Missouri jurisdictions, as applicable, that allow them to defer and subsequently recover or refund, through customer rates, substantially all of the variance in net energy costs from the amount set in base rates without a general rate case proceeding.

Weather significantly affects the amount of electricity that Evergy's customers use as electricity sales are seasonal. As summer peaking utilities, the third quarter typically accounts for the greatest electricity sales by the Evergy Companies. Hot summer temperatures and cold winter temperatures prompt more demand, especially among residential and commercial customers, and to a lesser extent, industrial customers. Mild weather reduces customer demand.

Energy efficiency investments by customers and the Evergy Companies also can affect the demand for electric service. Evergy Kansas Central, Evergy Metro and Evergy Missouri West offer energy efficiency and demand side management programs to their respective Kansas and Missouri retail customers and recover program costs, throughput disincentive, and as applicable, certain earnings opportunities in retail rates through a rider mechanism.

The Evergy Companies' taxes other than income tax, of which property taxes are a significant component, can fluctuate significantly due to a variety of factors, including changes in taxable values and property tax rates. Evergy Kansas Central, Evergy Metro and Evergy Missouri West have property tax surcharges or trackers that allow them to defer and subsequently recover or refund, through customer rates, substantially all of the variance in property tax costs from the amounts set in base rates.

The following table summarizes Evergy's comparative results of operations.

	2025	Change	2024
		(millions)	
Operating revenues	$ 5,961.6	$ 114.3	$ 5,847.3
Fuel and purchased power	1,412.4	(67.5)	1,479.9
SPP network transmission costs	438.0	67.1	370.9
Operating and maintenance	995.3	33.4	961.9
Depreciation and amortization	1,162.9	48.9	1,114.0
Taxes other than income tax	420.1	(32.5)	452.6
Income from operations	1,532.9	64.9	1,468.0
Other income (expense), net	(25.6)	(28.7)	3.1
Interest expense	616.3	53.2	563.1
Income tax expense	29.9	(0.1)	30.0
Equity in earnings of equity method investees, net of income taxes	6.8	(1.0)	7.8
Net income	867.9	(17.9)	885.8
Less: Net income attributable to noncontrolling interests	12.3	—	12.3
Net income attributable to Evergy, Inc.	$ 855.6	$ (17.9)	$ 873.5

Gross Margin (GAAP) and Utility Gross Margin (non-GAAP)

The following table summarizes Evergy's gross margin (GAAP) and MWhs sold and reconcile Evergy's gross margin (GAAP) to Evergy's utility gross margin (non-GAAP). See "Executive Summary - Non-GAAP Measures" for additional information regarding gross margin (GAAP) and utility gross margin (non-GAAP).

	Revenues and Expenses			MWhs Sold		
	2025	Change	2024	2025	Change	2024
Retail revenues		(millions)			(thousands)	
Residential	$ 2,198.6	$ 12.0	$ 2,186.6	15,955	245	15,710
Commercial	1,950.5	(13.2)	1,963.7	18,676	401	18,275
Industrial	649.9	(32.1)	682.0	8,197	(191)	8,388
Other retail revenues	45.7	2.4	43.3	91	(10)	101
Total electric retail	4,844.7	(30.9)	4,875.6	42,919	445	42,474
Wholesale revenues	312.8	(7.7)	320.5	15,187	1,225	13,962
Transmission revenues	520.6	38.0	482.6	N/A	N/A	N/A
Other revenues	283.5	114.9	168.6	N/A	N/A	N/A
Operating revenues	5,961.6	114.3	5,847.3	58,106	1,670	56,436
Fuel and purchased power	(1,412.4)	67.5	(1,479.9)			
SPP network transmission costs	(438.0)	(67.1)	(370.9)			
Operating and maintenance[(a)]	(521.7)	4.0	(525.7)			
Depreciation and amortization	(1,162.9)	(48.9)	(1,114.0)			
Taxes other than income tax	(420.1)	32.5	(452.6)			
Gross margin (GAAP)	**2,006.5**	**102.3**	**1,904.2**			
Operating and maintenance[(a)]	521.7	(4.0)	525.7			
Depreciation and amortization	1,162.9	48.9	1,114.0			
Taxes other than income tax	420.1	(32.5)	452.6			
Utility gross margin (non-GAAP)	**$ 4,111.2**	**$ 114.7**	**$ 3,996.5**			

[(a)] Operating and maintenance expenses which are deemed to be directly attributable to revenue-producing activities include plant operating and maintenance expenses at generating units and transmission and distribution operating and maintenance expenses and have been separately presented in order to calculate gross margin as defined under GAAP. These amounts exclude general and administrative expenses not directly attributable to revenue-producing activities of $473.6 million and $436.2 million for 2025 and 2024, respectively.

Evergy's gross margin (GAAP) increased $102.3 million in 2025, compared to 2024, and Evergy's utility gross margin (non-GAAP) increased $114.7 million in 2025, compared to 2024, both measures were driven by:

- a $133.7 million increase from new retail rates consisting of $105.1 million from Evergy Missouri West retail rates effective in January 2025 and $28.6 million from Evergy Kansas Central retail rates effective in October 2025;
- a $38.0 million increase in transmission revenue primarily due to updated transmission costs reflected in Evergy Kansas Central's FERC transmission formula rate (TFR) effective in January 2025; and
- a $10.6 million increase primarily due to higher retail sales driven by favorable weather (heating degree days increased by 14%; partially offset by a 5% decrease in cooling degree days) and higher weather-normalized commercial demand; partially offset by
- a $40.4 million decrease in revenue from the Kansas property tax rider, which is offset in taxes other than income tax; and
- a $27.2 million decrease driven by items not included in fuel recovery mechanisms, including 2024 wholesale revenues related to Dogwood Energy Center (Dogwood), a higher portion of 2025 SPP transmission expenses, Crossroads Energy Center (Crossroads) transmission expenses and certain wholesale revenues at Evergy Kansas Central.

Additionally, the increase in Evergy's gross margin (GAAP) was also impacted by:

- a $48.9 million increase in depreciation and amortization as further described below; partially offset by
- a $32.5 million decrease in taxes other than income tax as further described below; and
- a $4.0 million decrease in operating and maintenance expenses which are determined to be directly attributable to revenue producing activities.

Operating and Maintenance
Evergy's operating and maintenance expense increased $33.4 million in 2025, compared to 2024, primarily driven by:

- a $14.2 million increase in general and administrative labor and employee benefits expense, including higher medical claims;
- an $8.7 million increase in credit loss expense primarily due to lower levels of net write-offs incurred compared to estimates in 2024; and
- a $7.0 million increase in legal costs due to increased litigation activity in 2025.

Depreciation and Amortization
Evergy's depreciation and amortization increased $48.9 million in 2025, compared to 2024, primarily due to capital additions.

Taxes Other Than Income Tax
Evergy's taxes other than income tax decreased $32.5 million in 2025, compared to 2024, primarily driven by a decrease in Evergy Kansas Central's and Evergy Metro's 2025 amortization of the Kansas property tax rider.

Other Income (Expense), Net
Evergy's other income, net in 2024 became other expense, net in 2025 as a result of a $28.7 million increase in net other expense items, primarily driven by:

- $48.7 million of realized, unrealized and impairment losses from Evergy's non-regulated investments in early-stage clean energy and energy solution companies; and
- a $7.8 million increase primarily due to recording lower Evergy Kansas Central COLI benefits in 2025; partially offset by
- $11.8 million of income related to a commercial solar generation project completed in 2025;
- a $7.0 million decrease in pension non-service costs; and
- a $3.3 million increase in equity AFUDC primarily at Evergy Kansas Central and Evergy Missouri West primarily driven by lower short-term debt balances in 2025.

Interest Expense
Evergy's interest expense increased $53.2 million in 2025, compared to 2024, primarily driven by:

- a $78.3 million increase due to issuances of long-term debt; and
- a $4.9 million increase due to lower debt AFUDC driven by lower short-term interest rates in 2025; partially offset by
- a $19.4 million decrease in interest expense due to the repayment of long-term debt; and
- a $13.5 million decrease due to increases in carrying costs deferred to a regulatory asset in accordance with PISA due to Evergy Kansas Central and Evergy Metro electing into Kansas PISA beginning July 2024.

EVERGY SIGNIFICANT BALANCE SHEET CHANGES
(December 31, 2025 compared to December 31, 2024)

- Evergy's regulatory assets - current increased $36.5 million primarily driven by a $41.2 million increase related to Evergy Missouri West's fuel recovery mechanism under-collections.
- Evergy's nuclear decommissioning trusts increased $137.0 million primarily driven by realized and unrealized gains on investments at Evergy Kansas Central's and Evergy Metro's nuclear decommissioning trusts.
- Evergy's current maturities of long-term debt decreased $284.7 million primarily due to the repayments of Evergy Metro's $350.0 million of 3.65% Senior Notes in August 2025, Evergy Kansas Central's $250.0 million of 3.25% First Mortgage Bonds (FMBs) in December 2025 and Evergy Missouri West's $36.0 million of 3.49% Senior Notes in August 2025, partially offset by the reclassifications from long-term to current of Evergy Kansas Central's $350.0 million of 2.55% FMBs that mature in July 2026.
- Evergy's commercial paper increased $186.4 million driven by increases of $424.8 million at Evergy, Inc., $150.4 million at Evergy Missouri West and $86.6 million at Evergy Metro, partially offset by a $475.4 million decrease at Evergy Kansas Central. Increases and decreases in commercial paper borrowings were driven by capital expenditures, dividend payments, long-term debt issuances and repayments and other general corporate purposes.
- Evergy's regulatory liabilities - current decreased $32.2 million primarily driven by a $21.3 million decrease related to the refund of Evergy Missouri West's fuel recovery mechanism over-collections.
- Evergy's other liabilities - current increased $84.7 million primarily due to a $70.7 million increase in advances from customers for the prepayment of customer-funded construction projects.
- Evergy's long-term debt, net increased $1,230.0 million primarily driven by Evergy Metro's issuance of $400.0 million of 5.125% Mortgage Bonds in August 2025, Evergy Kansas Central's issuances of $300.0 million each of 5.25% FMBs in March and December 2025, respectively, Evergy Kansas Central's issuance of $300.0 million of 4.70% Notes in March 2025 and Evergy Missouri West's issuance of $300.0 million of 5.25% FMBs in November 2025; partially offset by the reclassification from long-term to current of Evergy Kansas Central's $350.0 million of 2.55% FMBs that mature in July 2026. See Note 12 to the consolidated financial statements for additional information.
- Evergy's pension and post-retirement liability decreased $92.6 million primarily due to an increase in the value of plan assets.

LIQUIDITY AND CAPITAL RESOURCES

Evergy relies primarily upon cash from operations, short-term borrowings, debt, equity and hybrid security issuances and its existing cash and cash equivalents to fund its capital requirements. Evergy's capital requirements primarily consist of capital expenditures, payment of contractual obligations and other commitments and the payment of dividends to shareholders.

Capital Sources

Cash Flows from Operations

Evergy's cash flows from operations are driven by the regulated sale of electricity. These cash flows are relatively stable but the timing and level of these cash flows can vary based on weather and economic conditions, future regulatory proceedings, the timing of cash payments made for costs recoverable under regulatory mechanisms and the time such costs are recovered, and unanticipated expenses such as unplanned plant outages and storms. Evergy's cash flows from operations were $2,045.2 million, $1,983.7 million and $1,980.2 million in 2025, 2024 and 2023, respectively.

Short-Term Borrowings

As of December 31, 2025, Evergy had $1.1 billion of available borrowing capacity under its master credit facility. The available borrowing capacity under the master credit facility consisted of $199.1 million for Evergy, Inc.,

$476.1 million for Evergy Kansas Central, $253.6 million for Evergy Metro and $173.4 million for Evergy Missouri West. The Evergy Companies' borrowing capacity under the master credit facility also supports their issuance of commercial paper. See Note 11 to the consolidated financial statements for more information regarding the master credit facility.

Along with cash flows from operations and receivable sales facilities, Evergy generally uses borrowings under its master credit facility and the issuance of commercial paper to meet its day-to-day cash flow requirements. Evergy believes that its existing cash on hand and available borrowing capacity under its master credit facility provide sufficient liquidity for its existing capital requirements.

Long-Term Debt, Equity and Hybrid Security Issuances

From time to time, Evergy issues long-term debt, equity and hybrid securities to repay short-term debt, refinance maturing long-term debt and finance growth. In May 2025, Evergy entered into an equity distribution agreement, pursuant to which Evergy may sell, from time to time, up to an aggregate of $1.2 billion of its common stock through an At-the-Market Program (ATM Program), which may utilize forward sales agreements. Evergy subsequently entered into forward sale agreements under the ATM program which can be settled at Evergy's discretion on or prior to dates ranging from March 2027 to October 2027. As of December 31, 2025, the ATM Program had approximately $1.1 billion of common stock available for issuance.

As of December 31, 2025 and 2024, Evergy's capital structure, excluding short-term debt, was as follows:

	December 31	
	2025	**2024**
Common equity	43%	44%
Long-term debt, including VIEs	57%	56%

Under stipulations with the MPSC and KCC, Evergy, Evergy Kansas Central and Evergy Metro are required to maintain common equity at not less than 35%, 40% and 40%, respectively, of total capitalization. The master credit facility and certain debt instruments of the Evergy Companies also contain restrictions that require the maintenance of certain capitalization and leverage ratios. As of December 31, 2025, the Evergy Companies were in compliance with these covenants.

The Evergy Companies expect that cash generated from operations, proceeds from the issuance of long-term debt, equity and hybrid securities will be adequate to meet anticipated cash needs over the next five years.

Debt Issuances

Evergy expects to issue approximately $12.3 billion of securities, inclusive of hybrid debt securities with equity content attribution by the credit rating agencies, through debt capital markets between 2026 and 2030, subject to market conditions, which includes refinancing $3.9 billion of long-term debt maturities and open-market repurchases. See Note 12 to the consolidated financial statements for more information regarding significant debt issuances.

Equity Issuances

Evergy expects to issue $3.3 billion of equity between 2026 and 2030, subject to market conditions. At December 31, 2025, Evergy could have settled forward sale agreements outstanding through the ATM Program with physical delivery of 1.7 million shares of common stock to the respective counterparties in exchange for cash of $123.6 million. See Note 18 to the consolidated financial statements for more information.

Credit Ratings

The ratings of the Evergy Companies' debt securities by the credit rating agencies impact the Evergy Companies' liquidity, including the cost of borrowings under their master credit facility and in the capital markets. The Evergy Companies view maintenance of strong credit ratings as vital to their access to and cost of debt financing and, to that end, maintain an active and ongoing dialogue with the agencies with

respect to results of operations, financial position and future prospects. While a decrease in these credit ratings would not cause any acceleration of the Evergy Companies' debt, it could increase interest charges under the master credit facility. A decrease in credit ratings could also have, among other things, an adverse impact, which could be material, on the Evergy Companies' access to capital, the cost of funds, the ability to recover actual interest costs in state regulatory proceedings, the type and amounts of collateral required under supply agreements and Evergy's ability to provide credit support for its subsidiaries.

As of February 18, 2026, the major credit rating agencies rated the Evergy Companies' securities as detailed in the following table.

	Moody's Investors Service[a]	S&P Global Ratings[a]
Evergy		
Outlook	Stable	Stable
Corporate Credit Rating	--	BBB+
Senior Unsecured Debt	Baa2	BBB
Junior Subordinated Note	Baa3	BBB-
Commercial Paper	P-2	A-2
Evergy Kansas Central		
Outlook	Stable	Stable
Corporate Credit Rating	Baa1	BBB+
Senior Secured Debt	A2	A
Senior Unsecured Debt	Baa1	BBB+
Commercial Paper	P-2	A-2
Evergy Kansas South		
Outlook	Stable	Stable
Corporate Credit Rating	Baa1	BBB+
Senior Secured Debt	A2	A
Short-Term Rating	P-2	A-2
Evergy Metro		
Outlook	Stable	Stable
Corporate Credit Rating	Baa1	A-
Senior Secured Debt	A2	A
Senior Unsecured Debt	Baa1	A-
Commercial Paper	P-2	A-2
Evergy Missouri West		
Outlook	Stable	Stable
Corporate Credit Rating	Baa3	BBB+
Senior Secured Debt	Baa1	A
Commercial Paper	P-3	A-2

[a] A securities rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency.

Shelf Registration Statements and Regulatory Authorizations

Evergy

In August 2024, Evergy filed an automatic shelf registration statement on Form S-3 with the SEC. Under this Form S-3, which is uncapped, Evergy may issue debt and other securities, including common stock, in the future with the amounts, prices and terms to be determined at the time of future offerings. The automatic registration statement was filed to replace a similar Form S-3 upon expiration of its three-year term. The shelf registration statement expires in August 2027.

Evergy Kansas Central

In August 2024, Evergy Kansas Central filed an automatic shelf registration statement on Form S-3 with the SEC. Under this Form S-3, which is uncapped, Evergy Kansas Central may issue debt securities in the future with the amounts, prices and terms to be determined at the time of future offerings. The automatic registration statement was filed to replace a similar Form S-3 upon expiration of its three-year term. The shelf registration statement expires in August 2027.

Evergy Metro

In August 2024, Evergy Metro filed an automatic shelf registration statement on Form S-3 with the SEC. Under this Form S-3, which is uncapped, Evergy Metro may issue debt securities in the future with the amounts, prices and terms to be determined at the time of future offerings. The automatic registration statement was filed to replace a similar Form S-3 upon expiration of its three-year term. The shelf registration statement expires in August 2027.

The following table summarizes the regulatory short-term and long-term debt financing authorizations for Evergy Kansas Central, Evergy Kansas South, Evergy Metro and Evergy Missouri West and the remaining amount available under these authorizations as of December 31, 2025.

Type of Authorization	Commission	Expiration Date	Authorization Amount	Available Under Authorization
Evergy Kansas Central			(in millions)	
Short-Term Debt	FERC	December 2026	$ 1,250.0	$ 928.1
Evergy Kansas South				
Short-Term Debt	FERC	December 2026	$ 1,000.0	$ 921.2
Evergy Metro				
Short-Term Debt	FERC	December 2026	$ 1,250.0	$ 1,004.7
Evergy Missouri West				
Short-Term Debt	FERC	December 2026	$ 750.0	$ 423.4
Long-Term Debt	FERC	December 2026	$ 600.0	$ 300.0

In addition to the above regulatory authorizations, the Evergy Kansas Central, Evergy Kansas South, Evergy Metro and Evergy Missouri West mortgages each contain provisions restricting the amount of FMBs or mortgage bonds, as applicable, that can be issued by each entity. Evergy Kansas Central, Evergy Kansas South, Evergy Metro and Evergy Missouri West must comply with these restrictions prior to the issuance of additional FMBs, mortgage bonds or other secured indebtedness.

Under the Mortgage and Deed of Trust dated July 1, 1939, as amended and supplemented (Evergy Kansas Central Mortgage Indenture), additional Evergy Kansas Central mortgage bonds may be issued on the basis of 70% of property additions or retired bonds. As of December 31, 2025, $2.3 billion principal amount of additional FMBs could be issued under the most restrictive provisions in the mortgage, except in connection with certain refundings.

Under the Evergy Kansas South Mortgage and Deed of Trust, dated April 1, 1940, as amended and supplemented (Evergy Kansas South Mortgage Indenture), the amount of FMBs authorized is limited to a maximum of $3.5 billion and the issuance of FMBs is subject to limitations based on the amount of

bondable property additions. In addition, the mortgage prohibits additional FMBs from being issued, except in connection with certain refundings, unless Evergy Kansas South's net earnings before income taxes and before provision for retirement and depreciation of property for a period of 12 consecutive months within 15 months preceding the issuance are not less than either two and one-half times the annual interest charges on or 10% of the principal amount of all Evergy Kansas South FMBs outstanding after giving effect to the proposed issuance. As of December 31, 2025, approximately $2.9 billion principal amount of additional Evergy Kansas South FMBs could be issued under the most restrictive provisions in the mortgage, except in connection with certain refundings.

Under the General Mortgage Indenture and Deed of Trust dated as of December 1, 1986, as amended and supplemented (Evergy Metro Mortgage Indenture), additional Evergy Metro mortgage bonds may be issued on the basis of 75% of property additions or retired bonds. As of December 31, 2025, approximately $5.6 billion principal amount of additional Evergy Metro mortgage bonds could be issued under the most restrictive provisions in the mortgage.

Under the First Mortgage Indenture and Deed of Trust, dated as of March 1, 2022, as supplemented (Evergy Missouri West Mortgage Indenture), additional Evergy Missouri West mortgage bonds may be issued on the basis of 75% of property additions or retired bonds. As of December 31, 2025, approximately $2.1 billion principal amount of additional Evergy Missouri West mortgage bonds could be issued under the most restrictive provisions in the mortgage.

Cash and Cash Equivalents

As of December 31, 2025, Evergy had approximately $19.8 million of cash and cash equivalents on hand.

Nuclear Production Tax Credit

In 2022, the Inflation Reduction Act (IRA) was signed into law providing a transferable Production Tax Credit (PTC) for electricity produced by existing nuclear power plants. Beginning in 2024, nuclear units, including Wolf Creek, became eligible for a production tax credit through 2032. The credit may be used to offset Evergy's income tax liability or be transferred to an unrelated third party. The Evergy Companies have estimated the credit based on the existing Internal Revenue Service (IRS) regulations. The IRS may provide guidance regarding the type of revenue to be included in the computation of gross receipts in 2026 which may significantly reduce the amount of nuclear PTCs available to Evergy. If Evergy is able to monetize the nuclear PTCs, it could result in significant cash inflows. The tax benefits, if any, are expected to be returned to customers over time as a reduction to revenue in future regulatory proceedings. See Note 20 to the consolidated financial statements for more information regarding the nuclear PTC.

Capital Requirements

Capital Expenditures

Evergy expects to access the debt and equity markets for significant amounts of capital to fund the infrastructure investments outlined in the table below. The investments are part of Evergy's long-term strategy focused on affordability, reliability and sustainability, including the modernization and expansion of its generation fleet and in anticipation of growing demand in its service territory. These investments include other utility construction programs required to maintain Evergy's electric utility operations, ensure reliability and expand facilities related to providing electric service. These capital expenditures could include, but are not limited to, expenditures to develop new transmission lines and make improvements to or investments in power plants, transmission and distribution lines and equipment. Evergy's capital expenditures were $2,796.9 million, $2,336.6 million and $2,334.0 million in 2025, 2024 and 2023, respectively.

Capital expenditures projected for the next five years, excluding AFUDC, including costs of removal and net of cash proceeds received from contributions in aid of construction, are detailed in the following table. This capital expenditure forecast is subject to management's discretion and continual review and could change. See Part I, Item 1A, Risk Factors for information regarding potential risks to Evergy's capital expenditure plan.

	2026	2027	2028	2029	2030	Five-year total
			(millions)			
Generating facilities - new generation	$ 1,473	$ 1,980	$ 2,004	$ 2,283	$ 1,604	$ 9,344
Generating facilities - other	413	457	438	446	432	2,186
Transmission facilities	664	842	786	789	802	3,883
Distribution facilities	1,016	995	906	964	1,015	4,896
General facilities	242	272	266	275	232	1,287
Total capital expenditures	$ 3,808	$ 4,546	$ 4,400	$ 4,757	$ 4,085	$ 21,596

Significant Contractual Obligations and Other Commitments

In the course of its business activities, the Evergy Companies enter into a variety of contracts and commercial commitments. Some of these result in direct obligations reflected on Evergy's consolidated balance sheets while others are commitments, some firm and some based on projections, not reflected in Evergy's underlying consolidated financial statements.

The information in the following table is provided to summarize Evergy's significant cash obligations and commercial commitments. For purchase commitments related to 'Generating facilities - new generation' included in the table above in the 'Capital Expenditures' section, see Note 15 to the consolidated financial statements.

Payment due by period	2026	2027	2028	2029	2030	After 2030	Total
Long-term debt				(millions)			
Principal	$ 611.1	$ 1,795.7	$ 318.8	$ 819.8	$ 420.8	$ 9,473.5	$ 13,439.7
Interest	580.1	563.2	484.1	473.4	450.8	4,698.1	7,249.7
Pension and other post-retirement plans[(a)]	111.3	111.3	111.3	111.3	111.3	(a)	556.5
Purchase commitments							
Fuel	313.0	202.9	194.7	181.0	93.2	384.4	1,369.2
Power	73.7	83.9	104.9	123.8	105.6	176.1	668.0

[(a)] Evergy expects to make contributions to the pension and other post-retirement plans beyond 2030 but the amounts are not yet determined.

Long-term debt includes current maturities and $192.9 million of tax-exempt bonds with interest rates that are determined each week. The bondholders of these tax-exempt bonds are permitted to tender the tax-exempt bonds to the issuer for purchase and, if tendered, the issuer is obligated to purchase any such bonds that cannot be remarketed to other investors. These tax-exempt bonds are classified as long-term debt due to the issuer's intent and ability to utilize such borrowings as long-term financing. Long-term debt principal excludes $109.6 million of unamortized net discounts and debt issuance costs and a $76.1 million fair value adjustment recorded in connection with purchase accounting for the merger that created Evergy in 2018. Variable rate interest obligations are based on rates as of December 31, 2025.

Evergy expects to contribute $111.3 million to the pension and other post-retirement plans in 2026, of which the majority is expected to be paid by Evergy Kansas Central and Evergy Metro. Additional contributions to the plans are expected beyond 2030 in amounts at least sufficient to meet the greater of Employee Retirement Income Security Act of 1974, as amended (ERISA) or regulatory funding requirements; however, these amounts have not yet been determined. Amounts for years after 2026 are estimates based on information available in determining the amount for 2026. Actual amounts for years after 2026 could be significantly different than the estimated amounts in the table above.

Fuel commitments consist of commitments for nuclear fuel and coal in addition to coal and natural gas transportation costs. Power commitments consist of certain commitments for renewable energy under power purchase agreements, capacity purchases and firm transmission service.

As of December 31, 2025, Evergy has other insignificant commitments as well as other insignificant long-term liabilities recorded on its consolidated balance sheet, which are not included in the table above.

Common Stock Dividends

The amount and timing of dividends payable on Evergy's common stock are within the sole discretion of the Evergy Board. The amount and timing of dividends declared by the Evergy Board will be dependent on considerations such as Evergy's earnings, financial position, cash flows, capitalization ratios, regulation, reinvestment opportunities and debt covenants. Evergy targets a long-term dividend payout ratio of 50%-60% . See Note 1 to the consolidated financial statements for information on the common stock dividend declared by the Evergy Board in February 2026.

The Evergy Companies also have certain restrictions stemming from statutory requirements, corporate organizational documents, covenants and other conditions that could affect dividend levels. See Note 18 to the consolidated financial statements for further discussion of restrictions on dividend payments.

Cash Flows

The following table presents Evergy's cash flows from operating, investing and financing activities.

	2025	2024
	(millions)	
Cash flows from operating activities	$ 2,045.2	$ 1,983.7
Cash flows used in investing activities	(2,570.1)	(2,261.8)
Cash flows from financing activities	522.0	280.3

Cash Flows from Operating Activities

Evergy's cash flows from operating activities increased $61.5 million in 2025, compared to 2024, primarily driven by an increase in cash receipts for retail electric sales in 2025.

Cash Flows used in Investing Activities

Evergy's cash flows used in investing activities increased $308.3 million in 2025, compared to 2024, primarily driven by a $460.3 million increase in additions to property, plant and equipment driven by increased spending for a variety of capital projects, including infrastructure investments and construction of new generation facilities.

Cash Flows from Financing Activities

Evergy's cash flows from financing activities increased $241.7 million in 2025, compared to 2024, primarily driven by a $273.5 million increase in proceeds from long-term debt, net due to the issuance of $1,687.5 million of long-term debt in 2025, compared to the issuance of $1,414.0 million of long-term debt in 2024.

EVERGY KANSAS CENTRAL, INC.

MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

The below results of operations and related discussion for Evergy Kansas Central is presented in a reduced disclosure format in accordance with General Instruction (I)(2)(a) to Form 10-K.

The following table summarizes Evergy Kansas Central's comparative results of operations.

	2025	Change	2024
		(millions)	
Operating revenues	$ 3,060.3	$ 53.2	$ 3,007.1
Fuel and purchased power	538.9	(18.2)	557.1
SPP network transmission costs	438.0	67.1	370.9
Operating and maintenance	478.8	2.8	476.0
Depreciation and amortization	579.2	17.5	561.7
Taxes other than income tax	223.7	(27.0)	250.7
Income from operations	801.7	11.0	790.7
Other income, net	15.7	3.0	12.7
Interest expense	241.2	11.7	229.5
Income tax expense	16.3	4.1	12.2
Equity in earnings of equity method investees, net of income taxes	3.4	0.1	3.3
Net income	563.3	(1.7)	565.0
Less: Net income attributable to noncontrolling interests	12.3	—	12.3
Net income attributable to Evergy Kansas Central, Inc.	$ 551.0	$ (1.7)	$ 552.7

Evergy Kansas Central Gross Margin (GAAP) and Utility Gross Margin (non-GAAP)

The following table summarizes Evergy Kansas Central's gross margin (GAAP) and MWhs sold and reconciles Evergy Kansas Central's gross margin (GAAP) to Evergy Kansas Central's utility gross margin (non-GAAP). See "Executive Summary - Non-GAAP Measures" for additional information regarding gross margin (GAAP) and utility gross margin (non-GAAP).

	Revenues and Expenses			MWhs Sold		
	2025	Change	2024	2025	Change	2024
Retail revenues		(millions)			(thousands)	
Residential	$ 960.3	$ (23.2)	$ 983.5	6,656	5	6,651
Commercial	816.3	(26.4)	842.7	7,475	88	7,387
Industrial	425.0	(23.9)	448.9	5,174	(112)	5,286
Other retail revenues	24.3	(0.9)	25.2	36	(3)	39
Total electric retail	2,225.9	(74.4)	2,300.3	19,341	(22)	19,363
Wholesale revenues	266.2	29.0	237.2	9,721	747	8,974
Transmission revenues	483.0	28.0	455.0	N/A	N/A	N/A
Other revenues	85.2	70.6	14.6	N/A	N/A	N/A
Operating revenues	3,060.3	53.2	3,007.1	29,062	725	28,337
Fuel and purchased power	(538.9)	18.2	(557.1)			
SPP network transmission costs	(438.0)	(67.1)	(370.9)			
Operating and maintenance [(a)]	(231.2)	15.5	(246.7)			
Depreciation and amortization	(579.2)	(17.5)	(561.7)			
Taxes other than income tax	(223.7)	27.0	(250.7)			
Gross margin (GAAP)	**1,049.3**	**29.3**	**1,020.0**			
Operating and maintenance [(a)]	231.2	(15.5)	246.7			
Depreciation and amortization	579.2	17.5	561.7			
Taxes other than income tax	223.7	(27.0)	250.7			
Utility gross margin (non-GAAP)	**$ 2,083.4**	**$ 4.3**	**$ 2,079.1**			

[(a)] Operating and maintenance expenses which are deemed to be directly attributable to revenue-producing activities include plant operating and maintenance expenses at generating units and transmission and distribution operating and maintenance expenses and have been separately presented in order to calculate gross margin as defined under GAAP. These amounts exclude general and administrative expenses not directly attributable to revenue-producing activities of $247.6 million and $229.3 million in 2025 and 2024, respectively.

Evergy Kansas Central's gross margin (GAAP) increased $29.3 million in 2025, compared to 2024, and Evergy Kansas Central's utility gross margin (non-GAAP) increased $4.3 million in 2025, compared to 2024, both measures were driven by:

- a $28.6 million increase from new Evergy Kansas Central retail rates effective in October 2025; and
- a $28.0 million increase in transmission revenue primarily due to updated transmission costs reflected in Evergy Kansas Central's FERC TFR effective in January 2025; partially offset by
- a $33.4 million decrease in revenue from the Kansas property tax rider, which is offset in taxes other than income tax; and
- an $18.9 million decrease primarily due to lower retail sales driven by unfavorable weather (cooling degree days decreased 14%, partially offset by an 18% increase in heating degree days); partially offset by higher weather-normalized residential and commercial demand.

Additionally, the increase in Evergy Kansas Central's gross margin (GAAP) was also impacted by:

- a $27.0 million decrease in taxes other than income tax as described further below; and
- a $15.5 million decrease in operating and maintenance expenses which are determined to be directly attributable to revenue producing activities primarily driven by an $8.8 million decrease in transmission and distribution operating and maintenance expense as further described below; partially offset by
- a $17.5 million increase in depreciation and amortization as described further below.

Evergy Kansas Central Operating and Maintenance
Evergy Kansas Central's operating and maintenance expense increased $2.8 million in 2025, compared to 2024, primarily driven by:

- an $8.8 million increase in general and administrative labor and employee benefits expense, including higher medical claims; and
- a $3.8 million increase in credit loss expense primarily due to lower levels of net write-offs incurred compared to estimates in 2024; partially offset by
- an $8.8 million decrease in transmission and distribution operating and maintenance expenses primarily driven by a $9.7 million decrease in non-labor expense.

Evergy Kansas Central Depreciation and Amortization
Evergy Kansas Central's depreciation and amortization expense increased $17.5 million in 2025, compared to 2024, primarily due to capital additions.

Evergy Kansas Central Taxes Other than Income Tax
Evergy Kansas Central's taxes other than income tax decreased $27.0 million in 2025, compared to 2024, primarily driven by a decrease in the 2025 amortization of the Kansas property tax rider.

Evergy Kansas Central Other Income, Net
Evergy Kansas Central's other income, net increased $3.0 million in 2025, compared to 2024, primarily driven by:

- a $4.8 million increase in investment earnings primarily driven by higher interest income;
- a $3.0 million increase in equity AFUDC driven by lower short-term debt balances in 2025; and
- a $2.5 million decrease in pension non-service costs; partially offset by
- a $7.5 million decrease due to recording lower Evergy Kansas Central COLI benefits in 2025.

Evergy Kansas Central Interest Expense
Evergy Kansas Central's interest expense increased $11.7 million in 2025, compared to 2024, primarily driven by:

- a $25.1 million increase due to issuances of long-term debt; and
- a $6.7 million increase due to lower debt AFUDC driven by lower short-term interest rates in 2025; partially offset by
- an $11.0 million decrease due to increases in carrying costs deferred to a regulatory asset in accordance with PISA due to Evergy Kansas Central electing into Kansas PISA beginning July 2024.

Evergy Kansas Central Income Tax Expense
Evergy Kansas Central's income tax expense increased $4.1 million in 2025, compared to 2024, primarily driven by lower wind income tax credits in 2025.

EVERGY METRO, INC.

MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

The below results of operations and related discussion for Evergy Metro is presented in a reduced disclosure format in accordance with General Instruction (I)(2)(a) to Form 10-K.

The following table summarizes Evergy Metro's comparative results of operations.

	2025	Change	2024
		(millions)	
Operating revenues	$ 1,916.1	$ 22.4	$ 1,893.7
Fuel and purchased power	564.3	11.5	552.8
Operating and maintenance	297.2	15.5	281.7
Depreciation and amortization	408.8	8.2	400.6
Taxes other than income tax	141.3	(6.1)	147.4
Income from operations	504.5	(6.7)	511.2
Other income, net	0.1	(1.2)	1.3
Interest expense	139.9	(7.2)	147.1
Income tax expense	44.2	3.3	40.9
Net income	$ 320.5	$ (4.0)	$ 324.5

Evergy Metro Gross Margin (GAAP) and Utility Gross Margin (non-GAAP)

The following table summarizes Evergy Metro's gross margin (GAAP) and MWhs sold and reconciles Evergy Metro's gross margin (GAAP) to Evergy Metro's utility gross margin (non-GAAP). See "Executive Summary - Non-GAAP Measures" for additional information regarding gross margin (GAAP) and utility gross margin (non-GAAP).

	Revenues and Expenses			MWhs Sold		
	2025	Change	2024	2025	Change	2024
Retail revenues		(millions)			(thousands)	
Residential	$ 750.6	$ 11.8	$ 738.8	5,610	135	5,475
Commercial	781.5	4.8	776.7	7,464	94	7,370
Industrial	131.8	(0.9)	132.7	1,696	(15)	1,711
Other retail revenues	11.8	1.5	10.3	41	(4)	45
Total electric retail	1,675.7	17.2	1,658.5	14,811	210	14,601
Wholesale revenues	38.7	(43.9)	82.6	5,041	403	4,638
Transmission revenues	25.7	5.8	19.9	N/A	N/A	N/A
Other revenues	176.0	43.3	132.7	N/A	N/A	N/A
Operating revenues	1,916.1	22.4	1,893.7	19,852	613	19,239
Fuel and purchased power	(564.3)	(11.5)	(552.8)			
Operating and maintenance [(a)]	(201.0)	(0.3)	(200.7)			
Depreciation and amortization	(408.8)	(8.2)	(400.6)			
Taxes other than income tax	(141.3)	6.1	(147.4)			
Gross margin (GAAP)	**600.7**	**8.5**	**592.2**			
Operating and maintenance [(a)]	201.0	0.3	200.7			
Depreciation and amortization	408.8	8.2	400.6			
Taxes other than income tax	141.3	(6.1)	147.4			
Utility gross margin (non-GAAP)	**$ 1,351.8**	**$ 10.9**	**$ 1,340.9**			

[(a)] Operating and maintenance expenses which are deemed to be directly attributable to revenue-producing activities include plant operating and maintenance expenses at generating units and transmission and distribution operating and maintenance expenses and have been separately presented in order to calculate gross margin as defined under GAAP. These amounts exclude general and administrative expenses not directly attributable to revenue-producing activities of $96.2 million and $81.0 million in 2025 and 2024, respectively.

Evergy Metro's gross margin (GAAP) increased $8.5 million in 2025, compared to 2024, and Evergy Metro's utility gross margin (non-GAAP) increased $10.9 million in 2025, compared to 2024, both measures were driven by:

- a $12.2 million increase primarily due to higher retail sales driven by favorable weather (heating degree days increased 11% and cooling degree days increased 3%); and
- a $5.8 million increase in transmission revenue; partially offset by
- a $7.1 million decrease in revenue from the Kansas property tax rider, which is offset in taxes other than income tax; and

Additionally, the increase in Evergy Metro's gross margin (GAAP) was also impacted by:

- an $8.2 million increase in depreciation and amortization as further described below;
- a $0.3 million increase in operating and maintenance expenses which are determined to be directly attributable to revenue producing activities; partially offset by
- a $6.1 million decrease in taxes other than income tax, as further described below.

Evergy Metro Operating and Maintenance

Evergy Metro's operating and maintenance expense increased $15.5 million in 2025, compared to 2024, primarily driven by:

- a $7.0 million increase in general and administrative labor and employee benefits expense, including higher medical claims;

- a $4.6 million increase in legal costs due to increased litigation activity in 2025; and
- a $2.3 million increase in credit loss expense primarily due to lower levels of net write-offs incurred compared to estimates in 2024.

Evergy Metro Depreciation and Amortization
Evergy Metro's depreciation and amortization expense increased $8.2 million in 2025, compared to 2024, primarily due to capital additions.

Evergy Metro Taxes Other than Income Tax
Evergy Metro's taxes other than income tax decreased $6.1 million in 2025, compared to 2024, primarily driven by a decrease in the 2025 amortization of the Kansas property tax rider.

Evergy Metro Interest Expense
Evergy Metro's interest expense decreased $7.2 million in 2025, compared to 2024, primarily driven by:

- an $11.3 million decrease due to increases in carrying costs deferred to a regulatory asset in accordance with PISA due to a higher outstanding balance of qualified PISA additions and Evergy Metro electing into Kansas PISA beginning July 2024;
- a $5.6 million decrease in interest expense on short-term borrowings primarily due to lower weighted-average interest rates; and
- a $4.8 million decrease due to the repayment of long-term debt; partially offset by
- a $12.0 million increase due to issuances of long-term debt.

Evergy Metro Income Tax Expense
Evergy Metro's income tax expense increased $3.3 million in 2025, compared to 2024, primarily driven by lower income tax credits in 2025.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In the ordinary course of business, Evergy faces risks that are either non-financial or non-quantifiable. Such risks principally include business, legal, operational and credit risks and are not represented in the following analysis. See Part I, Item 1A, Risk Factors and Part II, Item 7, MD&A for further discussion of risk factors.

The Evergy Companies are exposed to market risks associated with commodity price and supply, interest rates and security prices. Commodity price risk is the potential adverse price impact related to the purchase or sale of electricity and energy-related products, including natural gas and coal. Credit risk is the potential adverse financial impact resulting from non-performance by a counterparty of its contractual obligations. Interest rate risk is the potential adverse financial impact related to changes in interest rates. In addition, Evergy's investments in trusts to fund nuclear plant decommissioning and non-qualified retirement benefits give rise to security price risk.

Management has established risk management policies and strategies to reduce the potentially adverse effects that the volatility of the markets may have on Evergy's operating results. During the ordinary course of business, the Evergy Companies' hedging strategies are reviewed to determine the hedging approach deemed appropriate based upon the circumstances of each situation. Though management believes its risk management practices are effective, it is not possible to identify and eliminate all risk. Evergy could experience losses, which could have a material adverse effect on its results of operations or financial position, due to many factors, including unexpectedly large or rapid movements or disruptions in the energy markets, regulatory-driven market rule changes and/or bankruptcy or non-performance of customers or counterparties, and/or failure of underlying transactions that have been hedged to materialize.

Hedging Strategies
From time to time, Evergy utilizes derivative instruments to execute risk management and hedging strategies. Derivative instruments, such as futures, forward contracts, swaps or options, derive their value from underlying

assets, indices, reference rates or a combination of these factors. These derivative instruments include negotiated contracts, which are referred to as over-the-counter derivatives, and instruments listed and traded on an exchange.

Commodity Price Risk

The Evergy Companies engage in the wholesale and retail sale of electricity as part of their regulated electric operations in addition to non-regulated energy marketing activities. These activities expose the Evergy Companies to risks associated with the price of electricity and other energy-related products. Exposure to these risks is affected by a number of factors including the quantity and availability of fuel used for generation and the quantity of electricity customers consume, as well as the wholesale market prices received by the Evergy Companies' generation resources and the wholesale market prices paid to procure power to serve customer load or satisfy regulatory or contractual obligations. Customers' electricity usage could also vary from year to year based on the weather or other factors. Quantities of fossil fuel used for generation vary from year to year based on the availability, price and deliverability of a given fuel type as well as planned and unplanned outages at facilities that use fossil fuels. Evergy's exposure to fluctuations in these factors is limited by the cost-based regulation of its regulated operations in Kansas and Missouri as these operations are typically allowed to recover substantially all of these costs through fuel recovery mechanisms. While there may be a delay in timing between when these costs are incurred and when they are recovered through rates, changes from year to year generally do not have a material impact on operating results. The majority of derivative instruments used to manage Evergy's commodity price exposure are either not designated as hedges or do not qualify for hedge accounting. Mark-to-market changes for these instruments entered into by regulated businesses are reflected as regulatory assets or regulatory liabilities on Evergy's consolidated balance sheets. Derivative instruments entered into for non-regulated energy marketing activities are marked-to-market each period, with changes in the fair value of the derivative instruments reflected in earnings. See Note 13 to the consolidated financial statements for more information.

Value at Risk (VaR) Associated with Energy Marketing Activities

Management uses a risk measurement model, which calculates VaR to measure Evergy's commodity price risk associated with its trading portfolio related to non-regulated energy marketing activities. The VaR is calculated using historical 30-day exponentially weighted 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 position.

The following table shows the end, high, average and low market risk associated with its trading portfolio related to non-regulated energy marketing activities as measured by VaR for the periods indicated. The information includes non-regulated financial and physical transactions that are not considered derivatives under U.S. GAAP but economically offset derivatives also included in the VaR model.

VaR Model Trading Portfolio								
Year Ended December 31, 2025				Year Ended December 31, 2024			
End	High	Average	Low	End	High	Average	Low
(millions)				(millions)			
$ 0.7	$ 2.8	$ 0.9	$ 0.1	$ 1.1	$ 3.6	$ 0.7	$ 0.1

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

Interest Rate Risk

Evergy manages interest rate risk and short and long-term liquidity by limiting its exposure to variable interest rate debt and debt-like financial instruments to a percentage of total debt, diversifying maturity dates and, from time to time, entering into interest rate hedging transactions. As of December 31, 2025, 10.0% of Evergy's total debt (including short-term borrowings consisting of short-term debt in excess of utility construction work in progress balances that is not eligible for capitalization as AFUDC and borrowings under Evergy's receivable sale facilities) were exposed to interest rate risk. Evergy computes and presents information regarding the sensitivity to changes in

interest rates for variable rate debt, short-term borrowings and current maturities of fixed rate debt by assuming a 100-basis-point change in the current interest rates applicable to such debt over the remaining time the debt is outstanding.

As of December 31, 2025, Evergy had $1,524.6 million of short-term borrowings, variable rate debt and current maturities of fixed rate debt exposed to variable interest rate sensitivity. A 100-basis-point change in interest rates applicable to this debt would impact Evergy's income before income taxes basis by approximately $13.2 million, net of AFUDC borrowed funds which represents the allowed cost of capital used to finance utility construction activity and is a reduction of interest expense.

Credit Risk

Evergy is exposed to counterparty credit risk largely in the form of accounts receivable from its retail and wholesale electric customers and through executory contracts with market risk exposure. The credit risk associated with accounts receivable from retail and wholesale customers is largely mitigated by Evergy's large number of individual customers spread across diverse customer classes and the ability to recover bad debt expense in customer rates. The Evergy Companies maintain credit policies and employ credit risk control mechanisms, such as letters of credit, when necessary to minimize their overall credit risk and monitor exposure. The credit risk associated with new large load customers is partially mitigated by the requirement that new large load customers post collateral equal to two years of minimum monthly bills at the time of signing the agreement, subject to established discounts based on creditworthiness. The Evergy Companies, at their discretion, may require additional collateral based on assessment of the overall creditworthiness of the counterparty. Credit risk of the Evergy Companies' derivative instruments relates to the potential adverse financial impact resulting from non-performance by a counterparty of its contractual obligations. See Note 13 to the consolidated financial statements for more information on potential loss on counterparty exposure for derivative instruments as of December 31, 2025.

Investment Risk

Evergy maintains trust funds, as required by the NRC, to fund its 94% share of decommissioning the Wolf Creek nuclear power plant and also maintains trusts to fund pension benefits as well as certain non-qualified retirement benefits. As of December 31, 2025, these funds were primarily invested in a diversified mix of equity and debt securities and reflected at fair value on Evergy's balance sheet. The equity securities in the trusts are exposed to price fluctuations in equity markets and the value of debt securities are exposed to changes in interest rates and other market factors.

As nuclear decommissioning costs are currently recovered in customer rates, Evergy defers both realized and unrealized gains and losses for these securities as an offset to its regulatory liability for decommissioning Wolf Creek and as such, fluctuations in the value of these securities do not impact earnings. A significant decline in the value of pension or non-qualified retirement assets could require Evergy to increase funding of its pension plans in future periods, which could adversely affect cash flows in those periods. In addition, a decline in the fair value of these plan assets, in the absence of additional cash contributions to the plans by Evergy, could increase the amount of pension cost required to be recorded in future periods by Evergy.

In addition to Evergy's investments in debt and equity securities in its nuclear decommissioning and pension trusts, Evergy has also historically made limited non-regulated equity and debt investments in early-stage energy solution companies. These limited investments are often in privately-owned companies that do not have readily determinable fair values. However, from time to time, these investments could have changes in fair value as a result of bankruptcies, acquisitions, mergers, initial public offerings, or observable market transactions for similar investments. In 2025, Evergy initiated a process to dispose of these investments and could experience changes in their value upon their ultimate liquidation. See Note 1 to the consolidated financial statements for more information on these investments as of and for the year ended December 31, 2025.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm
- Evergy, Inc. 67
- Evergy Kansas Central, Inc. 69
- Evergy Metro, Inc. 71

Evergy, Inc.
- Consolidated Statements of Comprehensive Income 73
- Consolidated Balance Sheets 74
- Consolidated Statements of Cash Flows 76
- Consolidated Statements of Changes in Equity 77

Evergy Kansas Central, Inc.
- Consolidated Statements of Income 78
- Consolidated Balance Sheets 79
- Consolidated Statements of Cash Flows 81
- Consolidated Statements of Changes in Equity 82

Evergy Metro, Inc.
- Consolidated Statements of Comprehensive Income 83
- Consolidated Balance Sheets 84
- Consolidated Statements of Cash Flows 86
- Consolidated Statements of Changes in Equity 87

Combined Notes to Consolidated Financial Statements
- Note 1: Summary of Significant Accounting Policies 88
- Note 2: Revenue 98
- Note 3: Receivables 101
- Note 4: Rate Matters and Regulation 103
- Note 5: Goodwill 110
- Note 6: Asset Retirement Obligations 110
- Note 7: Property, Plant & Equipment 111
- Note 8: Jointly-Owned Electric Utility Plants 112
- Note 9: Pension Plans and Post-Retirement Benefits 113
- Note 10: Equity Compensation 127
- Note 11: Short-Term Borrowings and Short-Term Bank Lines of Credit 129
- Note 12: Long-Term Debt 130
- Note 13: Derivative Instruments 134
- Note 14: Fair Value Measurements 139
- Note 15: Commitments and Contingencies 144
- Note 16: Guarantees 150
- Note 17: Related Party Transactions and Relationships 150
- Note 18: Shareholders' Equity 152
- Note 19: Variable Interest Entities 153
- Note 20: Taxes 155
- Note 21: Leases 160
- Note 22: Segment Information 165

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Evergy, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Evergy, Inc. and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of comprehensive income, changes in equity, and cash flows, for each of the three years in the period ended December 31, 2025, and the related notes and the financial statement schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements 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.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), 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 and our report dated February 18, 2026, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Rate Matters and Regulation - Impact of Rate Regulation on the Financial Statements - Refer to Notes 1 and 4 to the financial statements

Critical Audit Matter Description

The Company is subject to wholesale regulation by the Federal Energy Regulatory Commission and rate regulation by the Kansas Corporation Commission and by the Missouri Public Service Commission (collectively the "Commissions"), which have jurisdiction with respect to the rates of electric distribution companies in Kansas and Missouri, respectively. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules

to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures.

The Company's rates are subject to regulatory rate-setting processes and annual earnings oversight. Because the Commissions set the rates, the Company is allowed to charge customers based on allowable costs, including a reasonable return on equity, and the Company applies accounting standards that require the financial statements to reflect the effects of rate regulation, including the recording of regulatory assets and liabilities. The Company assesses whether the regulatory assets and regulatory liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs, and factors such as changes in applicable regulatory and political environments. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the Commissions will not approve: (1) full recovery of the costs of providing utility service or (2) full recovery of amounts invested in the utility business and a reasonable return on that investment.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs and (2) refunds or future rate reduction to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs deferred as regulatory assets and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities.
- We tested the effectiveness of management's controls over the initial recognition of amounts as regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We evaluated external information and compared it to management's recorded regulatory asset and liability balances for completeness. Such external information included relevant regulatory orders issued by the Commissions for the Company and other public utilities in Kansas and Missouri, as well as other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.
- We evaluated management's analysis, regarding probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery or a future reduction in rates.

/s/ DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 18, 2026

We have served as the Company's auditor since 2002.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholder and the Board of Directors of Evergy Kansas Central, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Evergy Kansas Central, Inc. and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of income, changes in equity, and cash flows, for each of the three years in the period ended December 31, 2025, and the related notes and the financial statement schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements 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.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Rate Matters and Regulation - Impact of Rate Regulation on the Financial Statements - Refer to Notes 1 and 4 to the financial statements

Critical Audit Matter Description

The Company is subject to wholesale regulation by the Federal Energy Regulatory Commission and rate regulation by the Kansas Corporation Commission (the "Commission"), which has jurisdiction with respect to the rates of electric distribution companies in Kansas. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures.

The Company's rates are subject to regulatory rate-setting processes and annual earnings oversight. Because the Commission sets the rates, the Company is allowed to charge customers based on allowable costs, including a reasonable return on equity, and the Company applies accounting standards that require the financial statements to reflect the effects of rate regulation, including the recording of regulatory assets and liabilities. The Company assesses whether the regulatory assets and regulatory liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs, and factors such as changes in applicable regulatory and political environments. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the Commission will not approve: (1) full recovery of the costs of providing utility service or (2) full recovery of amounts invested in the utility business and a reasonable return on that investment.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs and (2) refunds or future rate reduction to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commission, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commission included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of regulatory assets and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities.
- We tested the effectiveness of management's controls over the initial recognition of amounts as regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We evaluated external information and compared it to management's recorded regulatory asset and liability balances for completeness. Such external information included relevant regulatory orders issued by the Commission for the Company and other public utilities in Kansas, as well as other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commission's treatment of similar costs under similar circumstances.
- We evaluated management's analysis regarding probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery or a future reduction in rates.

/s/ DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 18, 2026

We have served as the Company's auditor since 2002.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholder and the Board of Directors of Evergy Metro, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Evergy Metro, Inc. and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2025, and the related notes and the financial statement schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements 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.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Rate Matters and Regulation - Impact of Rate Regulation on the Financial Statements - Refer to Notes 1 and 4 to the financial statements

Critical Audit Matter Description

The Company is subject to wholesale regulation by the Federal Energy Regulatory Commission and rate regulation by the Kansas Corporation Commission and by the Missouri Public Service Commission (collectively the "Commissions"), which have jurisdiction with respect to the rates of electric distribution companies in Kansas and Missouri, respectively. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules

to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures.

The Company's rates are subject to regulatory rate-setting processes and annual earnings oversight. Because the Commissions set the rates, the Company is allowed to charge customers based on allowable costs, including a reasonable return on equity, and the Company applies accounting standards that require the financial statements to reflect the effects of rate regulation, including the recording of regulatory assets and liabilities. The Company assesses whether the regulatory assets and regulatory liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs and factors such as changes in applicable regulatory and political environments. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the Commissions will not approve (1) full recovery of the costs of providing utility service or (2) full recovery of amounts invested in the utility business and a reasonable return on that investment.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs and (2) refunds or future rate reduction to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of regulatory assets and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities.
- We tested the effectiveness of management's controls over the initial recognition of amounts as regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We evaluated external information and compared it to management's recorded regulatory asset and liability balances for completeness. Such external information included relevant regulatory orders issued by the Commissions for the Company and other public utilities in Kansas and Missouri, as well as other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.
- We evaluated management's analysis regarding probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery, or a future reduction in rates.

/s/ DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 18, 2026

We have served as the Company's auditor since 2002.

EVERGY, INC.
Consolidated Statements of Comprehensive Income

Year Ended December 31	2025	2024	2023
		(millions, except per share amounts)	
OPERATING REVENUES	**$ 5,961.6**	$ 5,847.3	$ 5,508.2
OPERATING EXPENSES:			
Fuel and purchased power	**1,412.4**	1,479.9	1,494.8
SPP network transmission costs	**438.0**	370.9	302.6
Operating and maintenance	**995.3**	961.9	945.3
Depreciation and amortization	**1,162.9**	1,114.0	1,076.5
Taxes other than income tax	**420.1**	452.6	406.6
Total Operating Expenses	**4,428.7**	4,379.3	4,225.8
INCOME FROM OPERATIONS	**1,532.9**	1,468.0	1,282.4
OTHER INCOME (EXPENSE):			
Investment earnings (loss)	**(35.0)**	4.6	29.7
Other income	**46.4**	38.9	40.6
Other expense	**(37.0)**	(40.4)	(75.1)
Total Other Income (Expense), Net	**(25.6)**	3.1	(4.8)
Interest expense	**616.3**	563.1	525.8
INCOME BEFORE INCOME TAXES	**891.0**	908.0	751.8
Income tax expense	**29.9**	30.0	15.6
Equity in earnings of equity method investees, net of income taxes	**6.8**	7.8	7.4
NET INCOME	**867.9**	885.8	743.6
Less: Net income attributable to noncontrolling interests	**12.3**	12.3	12.3
NET INCOME ATTRIBUTABLE TO EVERGY, INC.	**$ 855.6**	$ 873.5	$ 731.3
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO EVERGY, INC. (see Note 1)			
Basic earnings per common share	**$ 3.71**	$ 3.79	$ 3.18
Diluted earnings per common share	**$ 3.66**	$ 3.79	$ 3.17
AVERAGE COMMON SHARES OUTSTANDING			
Basic	**230.5**	230.3	230.0
Diluted	**233.6**	230.6	230.5
COMPREHENSIVE INCOME			
NET INCOME	**$ 867.9**	$ 885.8	$ 743.6
Derivative hedging activity			
Gain on derivative hedging instruments	**0.6**	—	—
Income tax expense	**(0.1)**	—	—
Net gain on derivative hedging instruments	**0.5**	—	—
Reclassification to expenses, net of tax	**5.4**	5.4	5.4
Derivative hedging activity, net of tax	**5.9**	5.4	5.4
Defined benefit pension plans			
Net gain (loss) arising during period	**0.2**	0.7	(0.5)
Income tax (expense) benefit	**(0.1)**	(0.1)	0.1
Net gain (loss) arising during period, net of tax	**0.1**	0.6	(0.4)
Amortization of net gains included in net periodic benefit costs, net of tax	**(0.2)**	(0.2)	(0.1)
Change in unrecognized pension expense, net of tax	**(0.1)**	0.4	(0.5)
Total other comprehensive income	**5.8**	5.8	4.9
Comprehensive income	**873.7**	891.6	748.5
Less: Comprehensive income attributable to noncontrolling interest	**12.3**	12.3	12.3
COMPREHENSIVE INCOME ATTRIBUTABLE TO EVERGY, INC.	**$ 861.4**	$ 879.3	$ 736.2

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY, INC.
Consolidated Balance Sheets

	December 31	
	2025	2024
ASSETS	(millions, except share amounts)	
CURRENT ASSETS:		
Cash and cash equivalents	**$ 19.8**	$ 22.0
Receivables, net of allowance for credit losses of $15.3 and $15.7, respectively	**214.2**	245.4
Accounts receivable pledged as collateral	**402.0**	401.0
Fuel inventory and supplies	**828.9**	867.4
Income taxes receivable	**8.2**	11.1
Regulatory assets, includes $16.7 and $15.9 related to variable interest entity, respectively	**217.4**	180.9
Prepaid expenses	**77.9**	66.1
Other	**47.4**	45.4
Total Current Assets	**1,815.8**	1,839.3
PROPERTY, PLANT AND EQUIPMENT, NET, includes $119.4 and $126.5 related to variable interest entity, respectively	**26,301.5**	24,930.9
OTHER ASSETS:		
Regulatory assets, includes $277.9 and $294.5 related to variable interest entity, respectively	**1,885.3**	1,719.3
Nuclear decommissioning trust	**1,016.8**	879.8
Goodwill	**2,336.6**	2,336.6
Other	**592.5**	576.2
Total Other Assets	**5,831.2**	5,511.9
TOTAL ASSETS	**$ 33,948.5**	$ 32,282.1

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY, INC.
Consolidated Balance Sheets

	December 31	
	2025	2024
LIABILITIES AND EQUITY	(millions, except share amounts)	
CURRENT LIABILITIES:		
Current maturities of long-term debt, includes $17.0 and $16.2 related to variable interest entity, respectively	**$ 367.0**	$ 651.7
Commercial paper	**1,394.0**	1,207.6
Collateralized note payable	**402.0**	401.0
Accounts payable	**654.3**	613.8
Accrued taxes	**169.4**	159.0
Accrued interest, includes $1.3 and $1.3 related to variable interest entity, respectively	**158.3**	136.4
Regulatory liabilities	**141.6**	173.8
Asset retirement obligations	**34.2**	28.7
Other	**375.1**	290.4
Total Current Liabilities	**3,695.9**	3,662.4
LONG-TERM LIABILITIES:		
Long-term debt, net, includes $279.2 and $295.7 related to variable interest entity, respectively	**13,039.2**	11,809.2
Deferred income taxes	**2,020.7**	2,035.7
Unamortized investment tax credits	**155.8**	162.8
Regulatory liabilities	**2,824.6**	2,672.0
Pension and post-retirement liability	**278.7**	371.3
Asset retirement obligations	**1,308.1**	1,268.3
Other	**357.7**	311.2
Total Long-Term Liabilities	**19,984.8**	18,630.5
Commitments and Contingencies (Note 15)		
EQUITY:		
Evergy, Inc. Shareholders' Equity:		
Common stock - 600,000,000 shares authorized, without par value 230,262,674 and 229,983,615 shares issued, stated value	**7,273.1**	7,245.9
Retained earnings	**2,966.2**	2,732.9
Accumulated other comprehensive loss	**(18.0)**	(23.8)
Total Evergy, Inc. Shareholders' Equity	**10,221.3**	9,955.0
Noncontrolling Interests	**46.5**	34.2
Total Equity	**10,267.8**	9,989.2
TOTAL LIABILITIES AND EQUITY	**$ 33,948.5**	$ 32,282.1

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY, INC.
Consolidated Statements of Cash Flows

Year Ended December 31	2025	2024	2023
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:		(millions)	
Net income	**$ 867.9**	$ 885.8	$ 743.6
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**1,162.9**	1,114.0	1,076.5
Amortization of nuclear fuel	**55.2**	56.5	62.4
Amortization of deferred refueling outage	**11.7**	17.2	18.2
Amortization of corporate-owned life insurance	**26.6**	23.8	25.1
Stock compensation	**20.7**	15.2	17.7
Net deferred income taxes and credits	**20.9**	(8.6)	(16.6)
Allowance for equity funds used during construction	**(22.9)**	(19.6)	(10.8)
Payments for asset retirement obligations	**(13.3)**	(12.1)	(21.8)
Equity in earnings of equity method investees, net of income taxes	**(6.8)**	(7.8)	(7.4)
Income from corporate-owned life insurance	**(8.6)**	(18.5)	(30.0)
(Gains) losses from investments in early-stage clean energy and energy solution companies	**48.7**	—	—
Other	**1.5**	—	1.5
Changes in working capital items:			
Accounts receivable	**19.9**	16.7	54.5
Accounts receivable pledged as collateral	**(1.0)**	(59.0)	17.0
Fuel inventory and supplies	**38.9**	(89.2)	(102.4)
Prepaid expenses and other current assets	**(18.2)**	156.5	136.6
Accounts payable	**(6.8)**	46.0	(47.2)
Accrued taxes	**13.4**	2.7	(8.6)
Other current liabilities	**(49.5)**	(80.7)	(43.8)
Changes in other assets	**(11.6)**	8.1	21.7
Changes in other liabilities	**(104.4)**	(63.3)	94.0
Cash Flows from Operating Activities	**2,045.2**	1,983.7	1,980.2
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	**(2,796.9)**	(2,336.6)	(2,334.0)
Acquisition of Persimmon Creek, net of cash acquired	**—**	—	(217.9)
Purchase of securities - trusts	**(335.6)**	(175.5)	(58.7)
Sale of securities - trusts	**292.3**	138.5	35.1
Proceeds from nonrefundable contributions in aid of construction	**170.0**	—	—
Investment in corporate-owned life insurance	**(15.3)**	(15.6)	(16.0)
Proceeds from investment in corporate-owned life insurance	**54.0**	101.6	118.7
Other investing activities	**61.4**	25.8	1.1
Cash Flows used in Investing Activities	**(2,570.1)**	(2,261.8)	(2,471.7)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	**186.4**	255.8	(381.9)
Repayment of term loan facility	**—**	—	(500.0)
Collateralized short-term borrowings, net	**1.0**	59.0	(17.0)
Issuance of common stock	**1.1**	—	—
Proceeds from long-term debt	**1,687.5**	1,414.0	2,444.8
Retirements of long-term debt	**(751.1)**	(811.5)	(439.5)
Borrowings against cash surrender value of corporate-owned life insurance	**48.5**	51.5	53.2
Repayment of borrowings against cash surrender value of corporate-owned life insurance	**(43.8)**	(76.1)	(89.8)
Proceeds from refundable advances for construction	**27.0**	—	—
Cash dividends paid	**(613.1)**	(596.7)	(569.6)
Other financing activities	**(21.5)**	(15.7)	(6.2)
Cash Flows from Financing Activities	**522.0**	280.3	494.0
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	**(2.9)**	2.2	2.5
CASH, CASH EQUIVALENTS AND RESTRICTED CASH:			
Beginning of period	**29.9**	27.7	25.2
End of period	**$ 27.0**	$ 29.9	$ 27.7

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY, INC.
Consolidated Statements of Changes in Equity

	Evergy, Inc. Shareholders					
	Common stock shares	Common stock	Retained earnings	AOCI	Non-controlling interests	Total equity
	(millions, except share amounts)					
Balance as of December 31, 2022	229,546,105	$ 7,219.7	$ 2,298.5	$ (34.5)	$ 9.6	$ 9,493.3
Net income	—	—	731.3	—	12.3	743.6
Issuance of stock compensation and reinvested dividends, net of tax withholding	183,191	(2.5)	—	—	—	(2.5)
Dividends declared on common stock ($2.48 per share)	—	—	(569.6)	—	—	(569.6)
Dividend equivalents declared	—	—	(2.4)	—	—	(2.4)
Stock compensation	—	17.5	—	—	—	17.5
Unearned compensation						
Compensation expense recognized	—	0.2	—	—	—	0.2
Derivative hedging activity, net of tax	—	—	—	5.4	—	5.4
Change in unrecognized pension expense, net of tax	—	—	—	(0.5)	—	(0.5)
Balance as of December 31, 2023	229,729,296	7,234.9	2,457.8	(29.6)	21.9	9,685.0
Net income	—	—	873.5	—	12.3	885.8
Issuance of stock compensation and reinvested dividends, net of tax withholding	254,319	(4.8)	—	—	—	(4.8)
Dividends declared on common stock ($2.595 per share)	—	—	(596.7)	—	—	(596.7)
Dividend equivalents declared	—	—	(1.7)	—	—	(1.7)
Stock compensation	—	15.2	—	—	—	15.2
Derivative hedging activity, net of tax	—	—	—	5.4	—	5.4
Change in unrecognized pension expense, net of tax	—	—	—	0.4	—	0.4
Other	—	0.6	—	—	—	0.6
Balance as of December 31, 2024	229,983,615	7,245.9	2,732.9	(23.8)	34.2	9,989.2
Net income	—	—	855.6	—	12.3	867.9
Issuance of stock, net of issuance costs	127,295	8.9	—	—	—	8.9
Issuance of stock compensation and reinvested dividends, net of tax withholding	151,764	(3.1)	—	—	—	(3.1)
Dividends declared on common stock ($2.6975 per share)	—	—	(620.8)	—	—	(620.8)
Dividend equivalents declared	—	—	(1.5)	—	—	(1.5)
Stock compensation	—	20.7	—	—	—	20.7
Derivative hedging activity, net of tax	—	—	—	5.9	—	5.9
Change in unrecognized pension expense, net of tax	—	—	—	(0.1)	—	(0.1)
Other	—	0.7	—	—	—	0.7
Balance as of December 31, 2025	230,262,674	$ 7,273.1	$ 2,966.2	$ (18.0)	$ 46.5	$ 10,267.8

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY KANSAS CENTRAL, INC.
Consolidated Statements of Income

Year Ended December 31	2025	2024	2023
		(millions)	
OPERATING REVENUES	**$ 3,060.3**	$ 3,007.1	$ 2,698.4
OPERATING EXPENSES:			
Fuel and purchased power	**538.9**	557.1	592.6
SPP network transmission costs	**438.0**	370.9	302.6
Operating and maintenance	**478.8**	476.0	477.3
Depreciation and amortization	**579.2**	561.7	515.5
Taxes other than income tax	**223.7**	250.7	219.8
Total Operating Expenses	**2,258.6**	2,216.4	2,107.8
INCOME FROM OPERATIONS	**801.7**	790.7	590.6
OTHER INCOME (EXPENSE):			
Investment earnings	**7.5**	2.7	3.4
Other income	**25.4**	28.7	34.3
Other expense	**(17.2)**	(18.7)	(38.7)
Total Other Income (Expense), Net	**15.7**	12.7	(1.0)
Interest expense	**241.2**	229.5	214.6
INCOME BEFORE INCOME TAXES	**576.2**	573.9	375.0
Income tax expense (benefit)	**16.3**	12.2	(5.9)
Equity in earnings of equity method investees, net of income taxes	**3.4**	3.3	3.6
NET INCOME	**563.3**	565.0	384.5
Less: Net income attributable to noncontrolling interests	**12.3**	12.3	12.3
NET INCOME ATTRIBUTABLE TO EVERGY KANSAS CENTRAL, INC.	**$ 551.0**	$ 552.7	$ 372.2

The disclosures regarding Evergy Kansas Central included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY KANSAS CENTRAL, INC.
Consolidated Balance Sheets

	December 31	
	2025	2024
ASSETS	(millions, except share amounts)	
CURRENT ASSETS:		
Cash and cash equivalents	**$ 5.3**	$ 3.7
Receivables, net of allowance for credit losses of $7.3 and $7.8, respectively	**136.6**	133.1
Related party receivables	**59.8**	23.4
Accounts receivable pledged as collateral	**213.0**	215.0
Fuel inventory and supplies	**437.9**	472.5
Income taxes receivable	**—**	11.4
Regulatory assets	**76.7**	79.7
Prepaid expenses	**36.9**	30.2
Other	**17.5**	9.2
Total Current Assets	**983.7**	978.2
PROPERTY, PLANT AND EQUIPMENT, NET, includes $119.4 and $126.5 related to variable interest entity, respectively	**13,460.1**	12,880.1
OTHER ASSETS:		
Regulatory assets	**523.8**	446.6
Nuclear decommissioning trust	**466.0**	407.9
Other	**340.0**	296.3
Total Other Assets	**1,329.8**	1,150.8
TOTAL ASSETS	**$ 15,773.6**	$ 15,009.1

The disclosures regarding Evergy Kansas Central included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY KANSAS CENTRAL, INC.
Consolidated Balance Sheets

	December 31	
	2025	2024
LIABILITIES AND EQUITY	(millions, except share amounts)	
CURRENT LIABILITIES:		
Current maturities of long-term debt	**$ 350.0**	$ 250.0
Commercial paper	**321.9**	797.3
Collateralized note payable	**213.0**	215.0
Accounts payable	**256.4**	281.5
Related party payables	**27.9**	36.7
Accrued taxes	**134.6**	109.7
Accrued interest	**96.2**	79.2
Regulatory liabilities	**64.7**	76.6
Asset retirement obligations	**18.3**	16.5
Other	**199.2**	165.6
Total Current Liabilities	**1,682.2**	2,028.1
LONG-TERM LIABILITIES:		
Long-term debt, net	**4,883.1**	4,333.5
Deferred income taxes	**760.9**	805.6
Unamortized investment tax credits	**48.7**	52.4
Regulatory liabilities	**1,557.9**	1,475.8
Pension and post-retirement liability	**171.7**	218.2
Asset retirement obligations	**654.0**	631.3
Other	**176.9**	179.3
Total Long-Term Liabilities	**8,253.2**	7,696.1
Commitments and Contingencies (Note 15)		
EQUITY:		
Evergy Kansas Central, Inc. Shareholder's Equity:		
Common stock - 1,000 shares authorized, $0.01 par value, 1 share issued	**2,737.6**	2,737.6
Retained earnings	**3,054.1**	2,513.1
Total Evergy Kansas Central, Inc. Shareholder's Equity	**5,791.7**	5,250.7
Noncontrolling Interests	**46.5**	34.2
Total Equity	**5,838.2**	5,284.9
TOTAL LIABILITIES AND EQUITY	**$ 15,773.6**	$ 15,009.1

The disclosures regarding Evergy Kansas Central included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY KANSAS CENTRAL, INC.
Consolidated Statements of Cash Flows

Year Ended December 31	2025	2024	2023
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:		(millions)	
Net income	**$ 563.3**	$ 565.0	$ 384.5
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**579.2**	561.7	515.5
Amortization of nuclear fuel	**27.4**	28.1	30.9
Amortization of deferred refueling outage	**5.9**	8.6	9.1
Amortization of corporate-owned life insurance	**26.6**	23.8	25.1
Net deferred income taxes and credits	**(17.9)**	1.3	(38.4)
Allowance for equity funds used during construction	**(15.5)**	(12.5)	(6.4)
Payments for asset retirement obligations	**(7.8)**	(7.4)	(9.8)
Equity in earnings of equity method investees, net of income taxes	**(3.4)**	(3.3)	(3.6)
Income from corporate-owned life insurance	**(8.6)**	(18.5)	(30.0)
Other	**(5.5)**	(5.5)	(5.5)
Changes in working capital items:			
Accounts receivable	**(42.8)**	30.6	70.6
Accounts receivable pledged as collateral	**2.0**	(49.0)	19.0
Fuel inventory and supplies	**35.0**	(60.2)	(61.5)
Prepaid expenses and other current assets	**3.7**	73.1	65.3
Accounts payable	**(57.1)**	42.4	(26.4)
Accrued taxes	**36.3**	(1.3)	(25.9)
Other current liabilities	**(32.5)**	(105.8)	(26.0)
Changes in other assets	**(25.3)**	(15.4)	4.6
Changes in other liabilities	**(34.1)**	(15.7)	126.8
Cash Flows from Operating Activities	**1,028.9**	1,040.0	1,017.9
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	**(1,298.3)**	(1,274.6)	(1,196.8)
Acquisition of Persimmon Creek, net of cash acquired	**—**	—	(217.9)
Purchase of securities - trusts	**(244.5)**	(52.5)	(25.6)
Sale of securities - trusts	**208.6**	19.1	8.3
Proceeds from nonrefundable contributions in aid of construction	**88.4**	—	—
Investment in corporate-owned life insurance	**(14.6)**	(15.6)	(16.0)
Proceeds from investment in corporate-owned life insurance	**52.6**	97.6	117.4
Other investing activities	**31.1**	28.8	13.3
Cash Flows used in Investing Activities	**(1,176.7)**	(1,197.2)	(1,317.3)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Short-term debt, net	**(475.4)**	566.9	(542.4)
Collateralized short-term debt, net	**(2.0)**	49.0	(19.0)
Proceeds from long-term debt	**971.1**	—	690.5
Retirements of long-term debt	**(325.5)**	—	(50.0)
Net money pool borrowings	**—**	(261.4)	261.4
Borrowings against cash surrender value of corporate-owned life insurance	**45.5**	48.3	50.2
Repayment of borrowings against cash surrender value of corporate-owned life insurance	**(42.5)**	(72.2)	(88.6)
Cash dividends paid	**(10.0)**	(172.0)	—
Other financing activities	**(11.8)**	(6.9)	(2.2)
Cash Flows from Financing Activities	**149.4**	151.7	299.9
NET CHANGE IN CASH AND CASH EQUIVALENTS	**1.6**	(5.5)	0.5
CASH AND CASH EQUIVALENTS:			
Beginning of period	**3.7**	9.2	8.7
End of period	**$ 5.3**	$ 3.7	$ 9.2

The disclosures regarding Evergy Kansas Central included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY KANSAS CENTRAL, INC.
Consolidated Statements of Changes in Equity

	Evergy Kansas Central, Inc. Shareholder				
	Common stock shares	Common stock	Retained earnings	Non-controlling interests	Total equity
	(millions, except share amounts)				
Balance as of December 31, 2022	1	$ 2,737.6	$ 1,760.2	$ 9.6	$ 4,507.4
Net income	—	—	372.2	12.3	384.5
Balance as of December 31, 2023	1	2,737.6	2,132.4	21.9	4,891.9
Net income	—	—	552.7	12.3	565.0
Dividends declared on common stock	—	—	(172.0)	—	(172.0)
Balance as of December 31, 2024	1	2,737.6	2,513.1	34.2	5,284.9
Net income	—	—	551.0	12.3	563.3
Dividends declared on common stock	—	—	(10.0)	—	(10.0)
Balance as of December 31, 2025	1	$ 2,737.6	$ 3,054.1	$ 46.5	$ 5,838.2

The disclosures regarding Evergy Kansas Central included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY METRO, INC.
Consolidated Statements of Comprehensive Income

Year Ended December 31	2025	2024	2023
		(millions)	
OPERATING REVENUES	**$ 1,916.1**	$ 1,893.7	$ 1,889.0
OPERATING EXPENSES:			
Fuel and purchased power	**564.3**	552.8	530.9
Operating and maintenance	**297.2**	281.7	284.1
Depreciation and amortization	**408.8**	400.6	416.6
Taxes other than income tax	**141.3**	147.4	132.8
Total Operating Expenses	**1,411.6**	1,382.5	1,364.4
INCOME FROM OPERATIONS	**504.5**	511.2	524.6
OTHER INCOME (EXPENSE):			
Investment earnings	**5.5**	4.9	3.8
Other income	**6.1**	8.9	5.6
Other expense	**(11.5)**	(12.5)	(27.0)
Total Other Income (Expense), Net	**0.1**	1.3	(17.6)
Interest expense	**139.9**	147.1	135.8
INCOME BEFORE INCOME TAXES	**364.7**	365.4	371.2
Income tax expense	**44.2**	40.9	39.2
NET INCOME	**$ 320.5**	$ 324.5	$ 332.0
COMPREHENSIVE INCOME			
NET INCOME	**$ 320.5**	$ 324.5	$ 332.0
OTHER COMPREHENSIVE INCOME:			
Derivative hedging activity			
Reclassification to expenses, net of tax	**(0.3)**	(0.3)	(0.3)
Derivative hedging activity, net of tax	**(0.3)**	(0.3)	(0.3)
Total other comprehensive loss	**(0.3)**	(0.3)	(0.3)
COMPREHENSIVE INCOME	**$ 320.2**	$ 324.2	$ 331.7

The disclosures regarding Evergy Metro included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY METRO, INC.
Consolidated Balance Sheets

	December 31	
	2025	2024
ASSETS	(millions, except share amounts)	
CURRENT ASSETS:		
Cash and cash equivalents	**$ 3.3**	$ 3.7
Receivables, net of allowance for credit losses of $5.7 and $5.8, respectively	**45.9**	58.1
Related party receivables	**125.3**	126.1
Accounts receivable pledged as collateral	**139.0**	136.0
Fuel inventory and supplies	**279.9**	283.8
Regulatory assets	**42.6**	42.7
Prepaid expenses	**30.6**	25.6
Other	**23.1**	25.5
Total Current Assets	**689.7**	701.5
PROPERTY, PLANT AND EQUIPMENT, NET	**8,448.9**	8,292.4
OTHER ASSETS:		
Regulatory assets	**538.6**	429.4
Nuclear decommissioning trust	**550.8**	471.9
Other	**124.2**	81.5
Total Other Assets	**1,213.6**	982.8
TOTAL ASSETS	**$ 10,352.2**	$ 9,976.7

The disclosures regarding Evergy Metro included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY METRO, INC.
Consolidated Balance Sheets

	December 31	
	2025	2024
LIABILITIES AND EQUITY	(millions, except share amounts)	
CURRENT LIABILITIES:		
Current maturities of long-term debt	**$ —**	$ 350.0
Commercial paper	**245.3**	158.7
Collateralized note payable	**139.0**	136.0
Accounts payable	**257.9**	252.8
Related party payables	**23.2**	0.2
Accrued taxes	**42.1**	52.4
Accrued interest	**35.4**	32.1
Regulatory liabilities	**38.0**	38.5
Asset retirement obligations	**15.0**	11.8
Customer advances for construction	**75.9**	42.4
Other	**69.8**	65.0
Total Current Liabilities	**941.6**	1,139.9
LONG-TERM LIABILITIES:		
Long-term debt, net	**3,271.4**	2,873.4
Deferred income taxes	**743.8**	755.3
Unamortized investment tax credits	**104.8**	108.0
Regulatory liabilities	**1,141.3**	1,008.4
Pension and post-retirement liability	**91.4**	137.0
Asset retirement obligations	**506.5**	490.9
Other	**95.0**	87.6
Total Long-Term Liabilities	**5,954.2**	5,460.6
Commitments and Contingencies (Note 15)		
EQUITY:		
Common stock - 1,000 shares authorized, without par value, 1 share issued, stated value	**1,563.1**	1,563.1
Retained earnings	**1,890.2**	1,809.7
Accumulated other comprehensive income	**3.1**	3.4
Total Equity	**3,456.4**	3,376.2
TOTAL LIABILITIES AND EQUITY	**$ 10,352.2**	$ 9,976.7

The disclosures regarding Evergy Metro included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY METRO, INC.
Consolidated Statements of Cash Flows

Year Ended December 31	2025	2024	2023
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:		(millions)	
Net income	**$ 320.5**	$ 324.5	$ 332.0
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**408.8**	400.6	416.6
Amortization of nuclear fuel	**27.8**	28.4	31.5
Amortization of deferred refueling outage	**5.8**	8.6	9.1
Net deferred income taxes and credits	**24.4**	(0.4)	22.3
Allowance for equity funds used during construction	**(4.9)**	(7.1)	(4.4)
Payments for asset retirement obligations	**(5.3)**	(4.3)	(8.6)
Other	**(0.4)**	(0.4)	(0.4)
Changes in working capital items:			
Accounts receivable	**28.1**	10.7	(0.2)
Accounts receivable pledged as collateral	**(3.0)**	(10.0)	(2.0)
Fuel inventory and supplies	**3.9**	(19.2)	(24.0)
Prepaid expenses and other current assets	**(2.4)**	(0.5)	(15.3)
Accounts payable	**37.6**	4.2	(7.3)
Accrued taxes	**(10.3)**	6.7	5.4
Other current liabilities	**13.8**	2.3	(19.8)
Changes in other assets	**(25.9)**	(13.1)	14.2
Changes in other liabilities	**(19.8)**	(9.0)	(5.9)
Cash Flows from Operating Activities	**798.7**	722.0	743.2
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	**(737.6)**	(619.7)	(757.4)
Purchase of securities - trusts	**(91.1)**	(123.0)	(33.1)
Sale of securities - trusts	**83.7**	119.5	26.8
Proceeds from nonrefundable contributions in aid of construction	**50.7**	—	—
Net money pool lending	**—**	—	31.0
Other investing activities	**3.0**	3.6	3.5
Cash Flows used in Investing Activities	**(691.3)**	(619.6)	(729.2)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	**86.6**	(264.6)	312.3
Collateralized short-term debt, net	**3.0**	10.0	2.0
Proceeds from long-term debt	**418.9**	296.8	375.2
Retirements of long-term debt	**(373.4)**	—	(379.5)
Cash dividends paid	**(240.0)**	(141.0)	(325.0)
Other financing activities	**(2.9)**	(3.2)	1.2
Cash Flows used in Financing Activities	**(107.8)**	(102.0)	(13.8)
NET CHANGE IN CASH AND CASH EQUIVALENTS	**(0.4)**	0.4	0.2
CASH AND CASH EQUIVALENTS:			
Beginning of period	**3.7**	3.3	3.1
End of period	**$ 3.3**	$ 3.7	$ 3.3

The disclosures regarding Evergy Metro included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY METRO, INC
Consolidated Statements of Changes in Equity

	Common stock shares	Common Stock	Retained earnings	AOCI - Net gains (losses) on cash flow hedges	Total Equity
			(millions, except share amounts)		
Balance as of December 31, 2022	1	$ 1,563.1	$ 1,619.2	$ 4.0	$ 3,186.3
Net income	—	—	332.0	—	332.0
Dividends declared on common stock	—	—	(325.0)	—	(325.0)
Derivative hedging activity, net of tax	—	—	—	(0.3)	(0.3)
Balance as of December 31, 2023	1	1,563.1	1,626.2	3.7	3,193.0
Net income	—	—	324.5	—	324.5
Dividends declared on common stock	—	—	(141.0)	—	(141.0)
Derivative hedging activity, net of tax	—	—	—	(0.3)	(0.3)
Balance as of December 31, 2024	1	1,563.1	1,809.7	3.4	3,376.2
Net income	—	—	320.5	—	320.5
Dividends declared on common stock	—	—	(240.0)	—	(240.0)
Derivative hedging activity, net of tax	—	—	—	(0.3)	(0.3)
Balance as of December 31, 2025	1	$ 1,563.1	$ 1,890.2	$ 3.1	$ 3,456.4

The disclosures regarding Evergy Metro included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY, INC.
EVERGY KANSAS CENTRAL, INC.
EVERGY METRO, INC.

Combined Notes to Consolidated Financial Statements

The notes to consolidated financial statements that follow are a combined presentation for Evergy, Inc., Evergy Kansas Central, Inc. and Evergy Metro, Inc., all registrants under this filing. The terms "Evergy," "Evergy Kansas Central," "Evergy Metro" and "Evergy Companies" are used throughout this report. "Evergy" refers to Evergy, Inc. and its consolidated subsidiaries, unless otherwise indicated. "Evergy Kansas Central" refers to Evergy Kansas Central, Inc. and its consolidated subsidiaries, unless otherwise indicated. "Evergy Metro" refers to Evergy Metro, Inc. and its consolidated subsidiaries, unless otherwise indicated. "Evergy Companies" refers to Evergy, Evergy Kansas Central and Evergy Metro, collectively, which are individual registrants within the Evergy consolidated group.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization
Evergy is a public utility holding company incorporated in 2017 and headquartered in Kansas City, Missouri. Evergy operates primarily through the following wholly-owned direct subsidiaries listed below.

- Evergy Kansas Central, Inc. (Evergy Kansas Central) is an integrated, regulated electric utility that provides electricity to customers in the state of Kansas. Evergy Kansas Central has one active wholly-owned subsidiary with significant operations, Evergy Kansas South, Inc. (Evergy Kansas South).
- Evergy Metro, Inc. (Evergy Metro) is an integrated, regulated electric utility that provides electricity to customers in the states of Missouri and Kansas.
- Evergy Missouri West, Inc. (Evergy Missouri West) is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri.
- Evergy Transmission Company, LLC (Evergy Transmission Company) owns 13.5% of Transource Energy, LLC (Transource) with the remaining 86.5% owned by AEP Transmission Holding Company, LLC, a subsidiary of American Electric Power Company, Inc. (AEP). Transource is focused on the development of competitive electric transmission projects. Evergy Transmission Company accounts for its investment in Transource under the equity method.

Evergy Kansas Central also owns a 50% interest in Prairie Wind Transmission, LLC (Prairie Wind), which is a joint venture between Evergy Kansas Central and subsidiaries of AEP and Berkshire Hathaway Energy Company. Prairie Wind owns a 108-mile, 345 kilovolt (kV) double-circuit transmission line that provides transmission service in the Southwest Power Pool, Inc. (SPP). Evergy Kansas Central accounts for its investment in Prairie Wind under the equity method.

Evergy Kansas Central, Evergy Kansas South, Evergy Metro and Evergy Missouri West conduct business in their respective service territories using the name Evergy. Collectively, the Evergy Companies have approximately 15,800 megawatts (MWs) of owned generating capacity and renewable power purchase agreements and engage in the generation, transmission, distribution and sale of electricity to approximately 1.7 million customers in the states of Kansas and Missouri.

Principles of Consolidation
Each of Evergy's, Evergy Kansas Central's and Evergy Metro's consolidated financial statements includes the accounts of their subsidiaries and variable interest entities (VIEs) of which they are the primary beneficiary. Undivided interests in jointly-owned generation facilities are included on a proportionate basis. Intercompany transactions have been eliminated. The Evergy Companies assess financial performance and allocate resources on a consolidated basis (i.e., operate in one segment).

Evergy Metro elected not to apply "push-down accounting" related to the merger that created Evergy in 2018, whereby the adjustments of assets and liabilities to fair value and the resulting goodwill would be recorded on the financial statements of the acquired subsidiary. These adjustments for Evergy Metro, as well as those related to the other acquired assets and liabilities from the merger are only reflected on Evergy's consolidated financial statements.

Use of Estimates

The process of preparing financial statements in conformity with generally accepted accounting principles (GAAP) requires the use of estimates and assumptions that affect the reported amounts of certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, upon settlement, actual results may differ from estimated amounts.

Cash, Cash Equivalents and Restricted Cash

Cash equivalents consist of highly liquid investments with original maturities of three months or less at acquisition. Evergy has restricted cash included in Other Current Assets and Other Non-current Assets on Evergy's consolidated balance sheets to facilitate the servicing of Evergy Missouri West Storm Funding I, LLC's (Evergy Missouri West Storm Funding) debt and the funding requirements for a jointly-owned generation facility. See Note 19 for additional information on the VIE. The following table summarizes the cash, cash equivalents and restricted cash included on Evergy's consolidated balance sheets.

	December 31	
	2025	2024
Evergy	(millions)	
Current assets		
Cash and cash equivalents	$ 19.8	$ 22.0
Other	5.6	6.2
Other assets		
Other	1.6	1.7
Total cash, cash equivalents and restricted cash	$ 27.0	$ 29.9

Fuel Inventory and Supplies

The Evergy Companies record fuel inventory and supplies at average cost. The following table separately states the balances for fuel inventory and supplies.

	December 31	
	2025	2024
Evergy	(millions)	
Fuel inventory	$ 218.6	$ 264.2
Supplies	610.3	603.2
Fuel inventory and supplies	$ 828.9	$ 867.4
Evergy Kansas Central		
Fuel inventory	$ 114.9	$ 154.2
Supplies	323.0	318.3
Fuel inventory and supplies	$ 437.9	$ 472.5
Evergy Metro		
Fuel inventory	$ 69.6	$ 71.9
Supplies	210.3	211.9
Fuel inventory and supplies	$ 279.9	$ 283.8

Property, Plant and Equipment

The Evergy Companies record the value of property, plant and equipment, including that of VIEs, at cost. For plant, cost includes contracted services, direct labor and materials, indirect charges for engineering and supervision and an allowance for funds used during construction (AFUDC). AFUDC represents the allowed cost of capital used to finance utility construction activity. AFUDC equity funds are included as a non-cash item in other income and AFUDC borrowed funds are a reduction of interest expense. AFUDC is computed by applying a composite rate to qualified construction work in progress (CWIP). The rates used to compute gross AFUDC are compounded semi-annually.

The amounts of the Evergy Companies' AFUDC for borrowed and equity funds are detailed in the following table.

	2025	2024	2023
Evergy		(millions)	
AFUDC borrowed funds	$ 36.9	$ 41.8	$ 39.3
AFUDC equity funds	22.9	19.6	10.8
Total	$ 59.8	$ 61.4	$ 50.1
Evergy Kansas Central			
AFUDC borrowed funds	$ 18.0	$ 24.7	$ 22.2
AFUDC equity funds	15.5	12.5	6.4
Total	$ 33.5	$ 37.2	$ 28.6
Evergy Metro			
AFUDC borrowed funds	$ 9.1	$ 11.6	$ 11.8
AFUDC equity funds	4.9	7.1	4.4
Total	$ 14.0	$ 18.7	$ 16.2

The average rates used in the calculation of AFUDC are detailed in the following table.

	2025	2024	2023
Evergy Kansas Central	4.6%	5.2%	5.7%
Evergy Metro	3.9%	5.8%	5.2%
Evergy Missouri West	5.1%	5.1%	5.6%

When property units are retired or otherwise disposed, the original cost, net of salvage, is charged to accumulated depreciation. Repair of property and replacement of items not considered to be units of property are expensed as incurred, except for planned refueling and maintenance outages at Wolf Creek Generating Station (Wolf Creek). As authorized by regulators, the incremental maintenance cost incurred for such outages is deferred and amortized to expense ratably over the period between planned outages.

Depreciation and Amortization

Depreciation and amortization of utility plant other than nuclear fuel is computed using the straight-line method over the estimated lives of depreciable property based on rates approved by state regulatory authorities. Annual depreciation rates average approximately 3%. See Note 7 for more details. Nuclear fuel is amortized to fuel expense based on the quantity of heat produced during the generation of electricity.

The depreciable lives of Evergy's, Evergy Kansas Central's and Evergy Metro's property, plant and equipment are detailed in the following table.

	Evergy			Evergy Kansas Central			Evergy Metro		
				(years)					
Generating facilities	5	to	66	5	to	66	7	to	58
Transmission facilities	27	to	66	29	to	63	27	to	64
Distribution facilities	10	to	63	13	to	61	10	to	54
Other	5	to	57	5	to	57	8	to	37

Abandoned Plant

When the Evergy Companies retire utility plant, the original cost, net of salvage, is charged to accumulated depreciation. However, when it becomes probable an asset will be retired significantly in advance of its original expected useful life and in the near term, the cost of the asset and related accumulated depreciation is recognized as a separate asset and a probable abandonment. If the asset is still in service, the net amount is classified as plant to be retired, net on the consolidated balance sheets. If the asset is no longer in service, the net amount is classified as a regulatory asset on the consolidated balance sheets.

The Evergy Companies must also assess the probability of full recovery of the remaining net book value of the abandonment. The net book value that may be retained as an asset on the balance sheet for the abandonment is dependent upon amounts that may be recovered through regulated rates, including any return. An impairment charge, if any, would equal the difference between the remaining net book value of the asset and the present value of the future revenues expected from the asset.

Nuclear Plant Decommissioning Costs

Nuclear plant decommissioning cost estimates are based on either the immediate dismantling method or the deferred dismantling method as determined by the State Corporation Commission of the State of Kansas (KCC) and Public Service Commission of the State of Missouri (MPSC) and include the costs of decontamination, dismantlement and site restoration. Based on these cost estimates, Evergy Kansas Central and Evergy Metro each contribute to a tax-qualified trust fund to be used to decommission Wolf Creek. Related liabilities for decommissioning are included on Evergy's, Evergy Kansas Central's and Evergy Metro's consolidated balance sheets in asset retirement obligations (AROs).

As a result of the authorized regulatory treatment and related regulatory accounting, differences between the fair value of the assets held in the nuclear decommissioning trust and the amounts recorded for the accumulated accretion and depreciation expense associated with the decommissioning ARO are recorded as a regulatory liability on Evergy's, Evergy Kansas Central's and Evergy Metro's consolidated balance sheets. See Note 6 for discussion of AROs including those associated with nuclear plant decommissioning costs.

Regulatory Accounting

Accounting standards are applied that recognize the economic effects of rate regulation. Accordingly, regulatory assets and liabilities have been recorded when required by a regulatory order or based on regulatory precedent. See Note 4 for additional information concerning regulatory matters.

Cash Surrender Value of Life Insurance
Amounts related to corporate-owned life insurance (COLI) are recorded on the consolidated balance sheets in other long-term assets and are detailed in the following table for Evergy. Substantially all of Evergy's COLI-related balances relate to Evergy Kansas Central's COLI activity.

	December 31	
	2025	2024
Evergy	(millions)	
Cash surrender value of policies	$ 1,331.0	$ 1,322.6
Borrowings against policies	(1,201.0)	(1,196.2)
Corporate-owned life insurance, net	$ 130.0	$ 126.4

Increases in cash surrender value and death benefits are recorded in other income in the Evergy Companies' consolidated statements of income and comprehensive income. Interest expense incurred on policy loans is offset against the policy income. Income from death benefits is highly variable from period to period.

Fair Value of Financial Instruments
The following methods and assumptions were used to estimate the fair value of the following financial instruments for which it was practicable to estimate that value.

Nuclear decommissioning trust - The Evergy Companies' nuclear decommissioning trust assets are recorded at fair value based on quoted market prices of the investments held by the fund and/or valuation models.

Derivative instruments - The Evergy Companies' derivative instruments are recorded at fair value based on quoted market prices for exchange-traded derivative instruments, quoted prices for similar contracts and/or valuation models.

Pension plans - For financial reporting purposes, the market value of plan assets is the fair value based on quoted market prices of the investments held by the fund and/or valuation models.

Derivative Instruments
The Evergy Companies record derivative instruments on the balance sheet at fair value in accordance with GAAP. The Evergy Companies enter into derivative contracts to manage risk exposure to commodity price and interest rate fluctuations and also for trading purposes. See Note 13 for additional information regarding derivative financial instruments and hedging activities.

Revenue Recognition
The Evergy Companies recognize revenue on the sale of electricity to customers over time as the service is provided in the amount they have the right to invoice. Revenues recorded include electric services provided but not yet billed by the Evergy Companies. Unbilled revenues are recorded for kilowatt hour (kWh) usage in the period following the customers' billing cycle to the end of the month. This estimate is based on net system kWh usage less actual billed kWhs. The Evergy Companies' estimated unbilled kWhs are allocated and priced by regulatory jurisdiction across the rate classes based on actual billing rates. The Evergy Companies' unbilled revenue estimate is affected by factors including fluctuations in energy demand, weather, line losses and changes in the composition of customer classes. See Note 3 for the balance of unbilled receivables for each of Evergy, Evergy Kansas Central and Evergy Metro as of December 31, 2025 and 2024.

The Evergy Companies also collect sales taxes and franchise fees from customers concurrent with revenue-producing activities that are levied by state and local governments. These items are excluded from revenue, and thus are not reflected on the consolidated statements of income and comprehensive income for Evergy, Evergy Kansas Central and Evergy Metro.

See Note 2 for additional details regarding revenue recognition from sales of electricity by the Evergy Companies.

Allowance for Credit Losses
Historical loss information generally provides the basis for the Evergy Companies' assessment of expected credit losses. The Evergy Companies use an aging of accounts receivable method to assess historical loss information. When historical experience may not fully reflect the Evergy Companies' expectations about the future, the Evergy Companies will adjust historical loss information, as necessary, to reflect the current conditions and reasonable and supportable forecasts not already reflected in the historical loss information.

Receivables are charged off when they are deemed uncollectible, which is based on a number of factors including specific facts surrounding an account and management's judgment.

Asset Impairments
Long-lived assets and finite-lived intangible assets subject to amortization are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the undiscounted expected future cash flows from an asset to be held and used is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. The amount of impairment recognized is the excess of the carrying value of the asset over its fair value.

Goodwill and indefinite lived intangible assets are tested for impairment annually and when an event occurs indicating the possibility that an impairment exists. The annual test must be performed at the same time each year. The goodwill impairment test consists of comparing the fair value of a reporting unit to its carrying amount, including goodwill, to identify potential impairment. In the event that the carrying amount exceeds the fair value of the reporting unit, an impairment loss is recognized for the difference between the carrying amount of the reporting unit and its fair value. See Note 5 for additional details on goodwill.

Income Taxes
Income taxes are accounted for using the asset/liability approach. Deferred tax assets and liabilities are determined based on the temporary differences between the financial reporting and tax bases of assets and liabilities, applying enacted statutory tax rates in effect for the year in which the differences are expected to reverse. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion of the deferred tax assets will not be realized.

The Evergy Companies recognize tax benefits based on a "more-likely-than-not" recognition threshold. In addition, the Evergy Companies recognize interest accrued related to unrecognized tax benefits in interest expense and penalties in operating expenses.

Evergy files a consolidated federal income tax return as well as unitary and combined income tax returns in several state jurisdictions with Kansas and Missouri being the most significant. Income taxes for consolidated or combined subsidiaries are allocated to the subsidiaries based on separate company computations of income or loss. Evergy Kansas Central's and Evergy Metro's income tax provisions include taxes allocated based on their separate company's income or loss.

The Evergy Companies have established a net regulatory liability for future refunds to be made to customers for amounts collected from customers in excess of income taxes in current rates. Tax credits are recognized in the year generated except for certain Evergy Kansas Central, Evergy Metro and Evergy Missouri West investment tax credits that have been deferred and amortized over the remaining service lives of the related properties.

Other Income and Other Expense

The tables below show the detail of other income and other expense, respectively, for each of the Evergy Companies.

Other Income	2025	2024	2023
Evergy		(millions)	
AFUDC equity	$ 22.9	$ 19.6	$ 10.8
Corporate-owned life insurance policy benefit	7.9	15.7	26.8
Income from commercial solar project	11.8	0.8	—
Other	3.8	2.8	3.0
Other income	$ 46.4	$ 38.9	$ 40.6
Evergy Kansas Central			
AFUDC equity	$ 15.5	$ 12.5	$ 6.4
Corporate-owned life insurance policy benefit	7.4	14.9	26.5
Other	2.5	1.3	1.4
Other income	$ 25.4	$ 28.7	$ 34.3
Evergy Metro			
AFUDC equity	$ 4.9	$ 7.1	$ 4.4
Other	1.2	1.8	1.2
Other income	$ 6.1	$ 8.9	$ 5.6

Other Expense	2025	2024	2023
Evergy		(millions)	
Non-service cost component of net benefit cost	$ (9.6)	$ (16.6)	$ (51.2)
Corporate-owned life insurance	(22.2)	(21.3)	(21.7)
Other	(5.2)	(2.5)	(2.2)
Other expense	$ (37.0)	$ (40.4)	$ (75.1)
Evergy Kansas Central			
Non-service cost component of net benefit cost	$ 4.6	$ 2.1	$ (17.6)
Corporate-owned life insurance	(21.1)	(20.2)	(20.6)
Other	(0.7)	(0.6)	(0.5)
Other expense	$ (17.2)	$ (18.7)	$ (38.7)
Evergy Metro			
Non-service cost component of net benefit cost	$ (9.1)	$ (10.1)	$ (24.8)
Corporate-owned life insurance	(1.1)	(1.0)	(1.1)
Other	(1.3)	(1.4)	(1.1)
Other expense	$ (11.5)	$ (12.5)	$ (27.0)

Investments in Early-Stage Clean Energy and Energy Solution Companies

From time to time, Evergy has made limited non-regulated equity and debt investments in early-stage clean energy and energy solution companies. These investments are recorded in Other Assets - Long-Term on Evergy's consolidated balance sheets and as of December 31, 2025, and December 31, 2024, the total value of these investments was $41.3 million and $121.4 million, respectively. These investments have historically not had a significant impact on Evergy's results of operations.

In 2025, Evergy recorded $48.7 million of losses in investment earnings (loss) on its consolidated statements of income and comprehensive income, resulting from a decline in fair value and losses on the sale of certain investments. The losses consisted of $13.5 million of realized losses and $35.2 million of unrealized and impairment losses.

Evergy has initiated a process to dispose of these investments and could experience additional losses or gains on these investments as a result of further changes in their value or upon their ultimate liquidation.

Earnings Per Share

To compute basic earnings per common share (EPS), Evergy divides net income attributable to Evergy, Inc. by the weighted average number of common shares outstanding. Diluted EPS includes the effect of issuable common shares resulting from restricted share units (RSUs), convertible notes, a warrant and forward sale agreements entered into through Evergy's at-the-market (ATM) equity offering program. Evergy computes the dilutive effects of potential issuances of common shares using the treasury stock method, the contingently issuable share method or the if-converted method, as applicable.

The following table reconciles Evergy's basic and diluted EPS.

	2025	2024	2023
Income		(millions, except per share amounts)	
Net income	$ 867.9	$ 885.8	$ 743.6
Less: Net income attributable to noncontrolling interests	12.3	12.3	12.3
Net income attributable to Evergy, Inc.	$ 855.6	$ 873.5	$ 731.3
Common Shares Outstanding			
Weighted average number of common shares outstanding - basic	230.5	230.3	230.0
Add: effect of dilutive securities	3.1	0.3	0.5
Diluted average number of common shares outstanding	233.6	230.6	230.5
Basic EPS	$ 3.71	$ 3.79	$ 3.18
Diluted EPS	$ 3.66	$ 3.79	$ 3.17

The effect of dilutive securities for 2025 included 2.6 million shares resulting from Evergy's convertible notes. There was no dilution resulting from Evergy's convertible notes in 2024 or 2023.

The table below summarizes the anti-dilutive securities excluded from the computation of diluted EPS.

Anti-Dilutive Securities	2025	2024	2023
		(shares in millions)	
Common shares issuable pursuant to a warrant	—	—	4.0
RSUs with performance measures	0.1	—	—

Supplemental Cash Flow Information

Evergy

Year Ended December 31	2025	2024	2023
Cash paid for (received from):		(millions)	
Interest, net of amount capitalized	$ 586.7	$ 538.5	$ 500.9
Interest of VIEs	16.1	13.1	—
Non-cash investing transactions:			
Property, plant and equipment additions	316.1	277.5	251.3
Non-cash financing transactions:			
Issuance of common stock for reinvested dividends	7.8	—	—

Evergy Kansas Central

Year Ended December 31	2025	2024	2023
Cash paid for (received from):		(millions)	
Interest, net of amount capitalized	$ 229.6	$ 220.6	$ 195.3
Non-cash investing transactions:			
Property, plant and equipment additions	159.5	158.0	134.1

Evergy Metro

Year Ended December 31	2025	2024	2023
Cash paid for (received from):		(millions)	
Interest, net of amount capitalized	$ 151.4	$ 145.9	$ 134.3
Non-cash investing transactions:			
Property, plant and equipment additions	65.5	86.3	83.2

Dividends Declared

In February 2026, Evergy's Board of Directors (Evergy Board) declared a quarterly dividend of $0.6950 per share on Evergy's common stock. The common stock dividend is payable March 20, 2026, to shareholders of record as of March 10, 2026.

In February 2026, Evergy Kansas Central's Board of Directors and Evergy Metro's Board of Directors each declared a cash dividend to Evergy of up to $50.0 million payable on or before March 19, 2026.

Missouri Legislation

In April 2025, Missouri Senate Bill (SB) 4 was signed into law by the Governor of Missouri. Most notably, SB 4 establishes new mechanisms for Missouri electric utilities to recover the costs associated with the construction of new natural gas-fired generating units. The utilities will be able to include certain costs of CWIP in rate base. The inclusion of CWIP will be in lieu of AFUDC applicable to the construction of the new natural gas-fired generating units. The MPSC will determine the amount of CWIP that may be included in rate base. Additionally, amounts collected arising from the inclusion of CWIP in rate base are subject to refund under certain circumstances. These provisions are scheduled to expire at the end of 2035. Additionally, the law extends Missouri's existing plant-in service accounting (PISA) provisions to include certain natural gas-fired generating units as qualifying electric plants and extends the sunset date of these provisions through the end of 2035. These provisions allow electric utilities to defer to a regulatory asset for recovery in a subsequent general rate case 85% of depreciation expense and the associated return on investment for qualifying electric plant rate base additions for assets placed in-service between general rate cases.

Natural Gas Plant Investments
The Evergy Companies use integrated resource plans (IRPs), detailed analyses that estimate factors that influence the future supply and demand for electricity, to inform the manner in which they supply electricity. The most recent IRPs incorporate the latest SPP resource adequacy requirements and anticipated load growth. Based on these and other factors, the IRP indicated the addition of new supply side resources, including combined and simple cycle natural gas plants, would be needed.

In October 2024, Evergy announced its plan to construct two combined-cycle natural gas plants located in Kansas. Evergy Kansas Central and Evergy Missouri West will jointly-own each plant and expect each plant to have an initial generating capacity of approximately 705 MWs. The first plant, a combined cycle gas turbine (CCGT) facility located in Sumner County, is expected to begin operations by spring of 2029 and the second plant, a CCGT facility located in Reno County, is expected to begin operations by spring of 2030.

Additionally, Evergy Missouri West plans to construct a 440 MW simple-cycle natural gas plant located in Missouri. The plant is expected to begin operations in 2030.

In 2024, Evergy Kansas Central and Evergy Missouri West requested predetermination from the KCC and a Certificate of Convenience and Necessity (CCN) from the MPSC, respectively, for their planned natural gas investments. In July 2025, the KCC approved a non-unanimous partial settlement agreement regarding Evergy Kansas Central's investments in its planned natural gas plants. In July 2025, the MPSC approved a non-unanimous stipulation and agreement regarding Evergy Missouri West's investments in its planned natural gas plants. See "Applications for Predetermination" and "Requests for Certificate of Convenience and Necessity" in Note 4 for additional information regarding Evergy Kansas Central's and Evergy Missouri West's applications for predetermination and a CCN for their investments in these natural gas plants.

Renewable Plant Investments
Evergy Kansas Central intends to construct and own an approximately 159 MW solar generation facility, to be located in Douglas County Kansas, called Kansas Sky. In July 2024, a lawsuit was filed in the District Court of Douglas County, *Grant Township, et al. v. Board of County Commissioners*, requesting the court to overturn Douglas County's approval of the application to construct the solar generation facility. Due to the ongoing litigation, including the court's granting of an emergency injunction in December 2024 which temporarily prohibits the construction of the solar generation facility, Evergy Kansas Central is not able to estimate when the solar generation facility will begin operations. In July 2025, the KCC approved a unanimous partial settlement agreement for the Kansas Sky solar investment. See "Applications for Predetermination" in Note 4 for additional information regarding Evergy Kansas Central's application for predetermination for its investment in this renewable generating plant.

In 2024, Evergy Missouri West entered into agreements to own two solar generation facilities currently under development. The first facility, to be called Sunflower Sky, is a solar generation facility to be located in Kansas with an expected generating capacity of approximately 65 MWs. In September 2025, Evergy Missouri West acquired the Sunflower Sky solar facility assets from the developer and will complete construction of the facility. The second facility, to be called Foxtrot, is a solar generation facility to be located in Missouri with an expected generating capacity of approximately 100 MWs. In November 2025, Evergy Missouri West acquired the Foxtrot solar facility assets from the developer and will complete construction of the facility. The solar generation facilities are expected to begin operations by summer of 2027. In July 2025, the MPSC approved a unanimous stipulation and agreement regarding Evergy Missouri West's planned investments in the solar generation facilities. See "Requests for Certificate of Convenience and Necessity" in Note 4 for additional information regarding Evergy Missouri West's application for a CCN for its investment in these renewable generating plants.

New Accounting Pronouncements
Improvements to Income Tax Disclosures
In December 2023, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2023-09, *Improvements to Income Tax Disclosures*. This ASU is intended to improve the transparency and

decision usefulness of income tax disclosures primarily by enhancing consistency in the categorization and disaggregation of information included in the effective tax rate reconciliation and income taxes paid by jurisdiction. This guidance is effective for annual periods beginning after December 15, 2025. The Evergy Companies adopted ASU No. 2023-09 retrospectively and it is reflected for all periods presented. The adoption of ASU No. 2023-09 did not have a material impact on the Evergy Companies' results of operations, financial positions, or cash flows. See Note 20 for further detail on the updated presentation.

Income Statement—Reporting Comprehensive Income: Expense Disaggregation Disclosures

In November 2024, the FASB issued ASU 2024-03, *Income Statement—Reporting Comprehensive Income: Expense Disaggregation Disclosures.* This ASU is intended to enhance income statement expense disclosures by requiring disaggregated information about specific expenses categories in commonly presented income statement expense captions. ASU No. 2024-03 is effective for annual periods beginning after December 15, 2026, and for interim periods beginning after December 15, 2027. Early adoption is permitted. The Evergy Companies are currently evaluating the disclosure impact of this ASU on their respective consolidated financial statements.

2. REVENUE

Evergy's, Evergy Kansas Central's and Evergy Metro's revenues disaggregated by customer class are summarized in the following tables.

Evergy

	2025	2024	2023
Revenues		(millions)	
Residential	$ 2,198.6	$ 2,186.6	$ 2,036.7
Commercial	1,950.5	1,963.7	1,832.4
Industrial	649.9	682.0	625.9
Other retail	45.7	43.3	43.2
Total electric retail	$ 4,844.7	$ 4,875.6	$ 4,538.2
Wholesale	312.8	320.5	373.5
Transmission	520.6	482.6	403.2
Industrial steam and other	27.0	25.7	30.2
Total revenue from contracts with customers	$ 5,705.1	$ 5,704.4	$ 5,345.1
Other	256.5	142.9	163.1
Operating revenues	$ 5,961.6	$ 5,847.3	$ 5,508.2

Evergy Kansas Central

	2025	2024	2023
Revenues		(millions)	
Residential	$ 960.3	$ 983.5	$ 821.0
Commercial	816.3	842.7	722.9
Industrial	425.0	448.9	398.5
Other retail	24.3	25.2	18.1
Total electric retail	$ 2,225.9	$ 2,300.3	$ 1,960.5
Wholesale	266.2	237.2	296.8
Transmission	483.0	455.0	385.8
Other	2.6	2.7	2.1
Total revenue from contracts with customers	$ 2,977.7	$ 2,995.2	$ 2,645.2
Other	82.6	11.9	53.2
Operating revenues	$ 3,060.3	$ 3,007.1	$ 2,698.4

Evergy Metro

	2025	2024	2023
Revenues		(millions)	
Residential	$ 750.6	$ 738.8	$ 748.4
Commercial	781.5	776.7	778.9
Industrial	131.8	132.7	130.9
Other retail	11.8	10.3	12.7
Total electric retail	$ 1,675.7	$ 1,658.5	$ 1,670.9
Wholesale	38.7	82.6	91.9
Transmission	25.7	19.9	14.3
Other	4.3	3.7	3.3
Total revenue from contracts with customers	$ 1,744.4	$ 1,764.7	$ 1,780.4
Other	171.7	129.0	108.6
Operating revenues	$ 1,916.1	$ 1,893.7	$ 1,889.0

Retail Revenues

The Evergy Companies' retail revenues are generated by the regulated sale of electricity to their residential, commercial and industrial customers within their franchised service territories. The Evergy Companies recognize revenue on the sale of electricity to their customers over time as the service is provided in the amount they have a right to invoice. Retail customers are billed monthly at the tariff rates approved by the KCC and MPSC based on customer kWh usage.

Revenues recorded include electric services provided but not yet billed by the Evergy Companies. Unbilled revenues are recorded for kWh usage in the period following the customers' billing cycle to the end of the month. This estimate is based on net system kWh usage less actual billed kWhs. The Evergy Companies' estimated unbilled kWhs are allocated and priced by regulatory jurisdiction across the rate classes based on actual billing rates.

The Evergy Companies also collect sales taxes and franchise fees from customers concurrent with revenue-producing activities that are levied by state and local governments. These items are excluded from revenue, and thus not reflected on the statements of income and comprehensive income, for Evergy, Evergy Kansas Central and Evergy Metro.

Wholesale Revenues

The Evergy Companies' wholesale revenues are generated by the sale of wholesale power and capacity in circumstances when the power that the Evergy Companies generate is not required for customers in their service territory. These sales primarily occur within the SPP Integrated Marketplace. The Evergy Companies also purchase power from the SPP Integrated Marketplace and record sale and purchase activity on a net basis in wholesale revenue or fuel and purchased power expense. In addition, the Evergy Companies sell wholesale power and capacity through bilateral contracts to other counterparties, such as electric cooperatives, municipalities and other electric utilities.

For both wholesale sales to the SPP Integrated Marketplace and through bilateral contracts, the Evergy Companies recognize revenue on the sale of wholesale electricity to their customers over time as the service is provided in the amount they have a right to invoice.

Wholesale sales within the SPP Integrated Marketplace are billed weekly based on the fixed transaction price determined by the market at the time of the sale and the megawatt hour (MWh) quantity sold. Wholesale sales from bilateral contracts are billed monthly based on the contractually determined transaction price and the kWh quantity sold.

Transmission Revenues

The Evergy Companies' transmission revenues are generated by the use of their transmission networks by the SPP. To enable optimal use of the diverse generating resources in the SPP region, the Evergy Companies, as well as other transmission owners, allow the SPP to access and operate their transmission networks. As new transmission lines are constructed, they are included in the transmission network available to the SPP. In exchange for providing access, the SPP pays the Evergy Companies consideration determined by formula rates approved by the Federal Energy Regulatory Commission (FERC), which include the cost to construct and maintain the transmission lines and a return on investment. The price for access to the Evergy Companies' transmission networks are updated annually based on projected costs. Projections are updated to actual costs and the difference is included in subsequent year's prices.

The Evergy Companies have different treatment for their legacy transmission facilities within the SPP, which results in different levels of transmission revenue being received from the SPP. Evergy Kansas Central's transmission revenues from SPP include amounts that Evergy Kansas Central pays to the SPP on behalf of its retail electric customers for the use of Evergy Kansas Central's legacy transmission facilities. These transmission revenues are mostly offset by SPP network transmission cost expense that Evergy Kansas Central pays on behalf of its retail customers. Evergy Metro and Evergy Missouri West do not pay the SPP for their retail customers' use of the Evergy Metro and Evergy Missouri West legacy transmission facilities and correspondingly, their transmission revenues also do not reflect the associated transmission revenue from the SPP.

The Evergy Companies recognize revenue on the sale of transmission service to their customers over time as the service is provided in the amount they have a right to invoice. Transmission service to the SPP is billed monthly based on a fixed transaction price determined by FERC formula transmission rates along with other SPP-specific charges and the MW quantity sold.

Industrial Steam and Other Revenues

Evergy's industrial steam and other revenues are primarily generated by the regulated sale of industrial steam to Evergy Missouri West's steam customers. Evergy recognizes revenue on the sale of industrial steam to its customers over time as the service is provided in the amount that it has the right to invoice. Steam customers are billed on a monthly basis at the tariff rate approved by the MPSC based on customer MMBtu usage.

3. RECEIVABLES

The Evergy Companies' receivables are detailed in the following table.

	December 31	
	2025	**2024**
Evergy	(millions)	
Customer accounts receivable - billed	$ 10.0	$ 2.7
Customer accounts receivable - unbilled	108.9	108.4
Other receivables	110.6	150.0
Allowance for credit losses	(15.3)	(15.7)
Total	$ 214.2	$ 245.4
Evergy Kansas Central		
Customer accounts receivable - unbilled	$ 42.8	$ 36.0
Other receivables	101.1	104.9
Allowance for credit losses	(7.3)	(7.8)
Total	$ 136.6	$ 133.1
Evergy Metro		
Customer accounts receivable - unbilled	$ 30.0	$ 28.5
Other receivables	21.6	35.4
Allowance for credit losses	(5.7)	(5.8)
Total	$ 45.9	$ 58.1

The Evergy Companies' other receivables as of December 31, 2025 and 2024, consisted primarily of receivables from partners in jointly-owned electric utility plants, wholesale sales receivables and receivables related to alternative revenue programs.

The Evergy Companies' other receivables also included receivables from contracts with customers as summarized in the following table.

	December 31	
	2025	**2024**
	(millions)	
Evergy	$ 64.2	$ 68.9
Evergy Kansas Central	59.7	65.3
Evergy Metro	2.9	2.6

The change in the Evergy Companies' allowance for credit losses is summarized in the following table.

	2025	2024
Evergy	(millions)	
Beginning balance January 1	$ 15.7	$ 24.2
Credit loss expense	20.4	11.7
Write-offs	(32.4)	(32.5)
Recoveries of prior write-offs	11.6	12.3
Ending balance December 31	$ 15.3	$ 15.7
Evergy Kansas Central		
Beginning balance January 1	$ 7.8	$ 11.6
Credit loss expense	10.4	6.6
Write-offs	(15.6)	(15.6)
Recoveries of prior write-offs	4.7	5.2
Ending balance December 31	$ 7.3	$ 7.8
Evergy Metro		
Beginning balance January 1	$ 5.8	$ 7.9
Credit loss expense	6.8	4.5
Write-offs	(11.8)	(11.6)
Recoveries of prior write-offs	4.9	5.0
Ending balance December 31	$ 5.7	$ 5.8

Sale of Accounts Receivable

Evergy Kansas Central, Evergy Metro and Evergy Missouri West sell an undivided percentage ownership interest in their retail electric accounts receivable to independent outside investors. These sales are accounted for as secured borrowings with accounts receivable pledged as collateral and a corresponding short-term collateralized note payable recognized on the balance sheets. The Evergy Companies' accounts receivable pledged as collateral and the corresponding short-term collateralized note payable are summarized in the following table.

	December 31	
	2025	2024
	(millions)	
Evergy	$ 402.0	$ 401.0
Evergy Kansas Central	213.0	215.0
Evergy Metro	139.0	136.0

In April 2025, Evergy Kansas Central, Evergy Metro and Evergy Missouri West extended the expiration of each receivable sale facility from November 2025 to April 2028. Evergy Kansas Central's facility allows up to $185.0 million in aggregate outstanding principal amount to be borrowed at any time. To the extent Evergy Kansas Central has qualifying accounts receivable and subject to the lender's discretion, Evergy Kansas Central's facility allows for an additional $65.0 million in aggregate outstanding principal amount to be borrowed at any time. Evergy Metro's facility allows up to $130.0 million in aggregate outstanding principal amount to be borrowed at any time. To the extent Evergy Metro has qualifying accounts receivable and subject to the lender's discretion, Evergy Metro's facility allows for an additional $70.0 million in aggregate outstanding principal amount to be borrowed at any time. Evergy Missouri West's facility allows up to $50.0 million in aggregate outstanding principal amount to be borrowed at any time. To the extent Evergy Missouri West has qualifying accounts receivable and subject to the lender's discretion, Evergy Missouri West's facility allows for an additional $65.0 million in aggregate outstanding principal amount to be borrowed at any time.

4. RATE MATTERS AND REGULATION

KCC Proceedings

Evergy Kansas Central's 2025 Rate Case Proceeding

In January 2025, Evergy Kansas Central filed an application with the KCC to request an increase to its retail revenues of approximately $196 million. Evergy Kansas Central's request reflected a return on equity of 10.5% (with a capital structure composed of 52% equity) and increases related to the recovery of infrastructure investments made to improve reliability and enhance customer service and the update of expenses to current levels of spend.

In July 2025, Evergy Kansas Central, KCC staff and other intervenors reached a unanimous settlement agreement to settle all issues in the case. The unanimous settlement agreement provides for an increase to retail revenues of $128.0 million after rebasing property tax expense and not including costs recoverable through KCC-approved riders for Evergy Kansas Central. In September 2025, the KCC approved the unanimous settlement agreement and new rates took effect in October 2025.

Earnings Review and Sharing

As part of the settlement agreement in Evergy Kansas Central's 2025 KCC rate case, Evergy Kansas Central agreed to participate in an earnings review surveillance report for each calendar year beginning 2025 through the time Evergy Kansas Central files its next general rate case and new base rates become effective as a result of that case. Under this mechanism, Evergy Kansas Central's jurisdiction is required to refund customers 50% of annual earnings in excess of a 9.7% return on equity.

As of December 31, 2025, Evergy Kansas Central estimates its 2025 annual earnings will not result in a refund obligation under the earnings review mechanism. Evergy Kansas Central expects to file its 2025 earnings calculation with the KCC in March 2026. The final refund obligation for 2025, if any, will be decided by the KCC and could vary from the current estimate.

Applications for Predetermination

The KCC uses a process referred to as 'predetermination' to establish ratemaking principles and treatments for certain utility investments before they are included in a utility's rate base. The process helps balance the interest of utilities and customers by ensuring broad agreement to the reasonableness of the investment and regulatory certainty regarding the recovery of costs associated with the investment. Investment in utility projects may be dependent on acceptable regulatory treatment determined in the predetermination process.

In November 2024, Evergy Kansas Central requested predetermination from the KCC for its planned natural gas plant investments and Kansas Sky solar investment. In April 2025, Evergy Kansas Central and intervenors in the case reached a non-unanimous partial settlement agreement regarding its planned natural gas plant investments and a unanimous partial settlement agreement regarding the Kansas Sky solar investment.

In July 2025, the KCC approved the non-unanimous partial settlement agreement for the natural gas plant investments establishing that Evergy Kansas Central's investment in its planned natural gas plants is prudent. This agreement will permit Evergy Kansas Central to implement a CWIP rider one year after construction of each plant begins and Evergy Kansas Central will recover through the CWIP rider the return on up to 100% of amounts recorded to CWIP for each plant, not to exceed definitive cost estimates established by the KCC unless otherwise ordered by the KCC. Evergy Kansas Central will be permitted to update rates charged through the CWIP rider every six months. Evergy Kansas Central will be permitted to collect these amounts through the CWIP rider until new base rates reflecting Evergy Kansas Central's investment in the natural gas plants take effect. Evergy Kansas Central will not be able to accrue AFUDC on these amounts once the CWIP rider becomes effective and is included in customer rates. When new base rates reflecting Evergy Kansas Central's investment in each plant take effect, those base rates will include a deferral for depreciation expense incurred and carrying costs on any unrecovered portion of Evergy Kansas Central's investment in natural gas plants incurred between the time the natural gas plants are placed in service and the time the investment in the natural gas plants is included in base rates. Investments above certain amounts established in the settlement agreement will be subject to a prudence review.

In July 2025, the KCC approved the unanimous partial settlement agreement for the Kansas Sky solar investment. After the investment is placed in service and prior to the effective date of rates that include the investment, Evergy

Kansas Central will be permitted to defer to a regulatory asset and recover over the remaining life of the Kansas Sky solar investment depreciation expense, carrying costs and other costs incurred. Thereafter, Evergy Kansas Central's investment in Kansas Sky will be recovered through a levelized revenue requirement for the first thirty years of the life of the generation site, after which the levelized revenue requirement will be reevaluated.

In July 2024, a lawsuit was filed in the District Court of Douglas County, *Grant Township, et al. v. Board of County Commissioners*, requesting the court to overturn Douglas County's approval of the application to construct the solar generation facility. Due to the ongoing litigation, including the court's granting of an emergency injunction in December 2024 which temporarily prohibits construction of the solar generation facility, Evergy Kansas Central is not able to estimate when the solar generation facility will begin operations.

Evergy Kansas Central 2025 Transmission Delivery Charge (TDC)
In April 2025, the KCC issued an order adjusting Evergy Kansas Central's retail prices to include updated transmission costs as reflected in the FERC transmission formula rate (TFR). The new prices were effective in May 2025 and are expected to increase Evergy Kansas Central's annual retail revenues by $54.8 million when compared to 2024.

Evergy Metro 2025 TDC
In April 2025, the KCC issued an order adjusting Evergy Metro's retail prices to include updated transmission costs as reflected in the FERC TFR. The new prices were effective in May 2025 and are expected to increase Evergy Metro's annual retail revenues by $4.8 million when compared to 2024.

MPSC Proceedings
Evergy Metro's 2026 Rate Case Proceeding
In February 2026, Evergy Metro filed an application with the MPSC to request an increase to its retail revenues of approximately $140 million. Evergy Metro's request reflected a return on equity of 10.5% (with a capital structure composed of 52% equity) and increases related to the recovery of infrastructure investments made to improve reliability and enhance customer service and the update of expenses to current levels of spend. New rates are expected to be effective in January 2027.

Evergy Missouri West's 2024 Rate Case Proceeding
In January 2025, Evergy Missouri West implemented new rates approved by the MPSC in December 2024 providing for an increase to Evergy Missouri West's retail revenues of approximately $55 million after lowering base rates for fuel and purchased power expense of approximately $49 million and rebasing property tax expense.

Requests for Certificate of Convenience and Necessity
Missouri utilities must request a CCN from the MPSC to authorize them to build certain utility projects. The CCN process authorizes utilities to build projects and can provide assurance that the project is prudent and necessary. Investment in projects is dependent upon the granting by the MPSC of a CCN with reasonably acceptable terms.

In 2024, Evergy Missouri West filed applications for CCNs for its planned renewable and natural gas plant investments. In May 2025, Evergy Missouri West entered into a unanimous stipulation and agreement with the MPSC staff and other intervenors that would grant Evergy Missouri West's CCNs to construct, install, own, operate, maintain and otherwise control and manage Sunflower Sky and Foxtrot solar generating facilities. In May 2025, Evergy Missouri West entered into a non-unanimous stipulation and agreement with the MPSC staff and other intervenors that would grant Evergy Missouri West's CCNs to construct, install, own, operate, maintain and otherwise control and manage its planned natural gas plant investments.

In July 2025, the MPSC approved the unanimous stipulation and agreement for Sunflower Sky and Foxtrot solar generating facilities granting Evergy Missouri West's CCN request for its planned renewable plant investments. Evergy Missouri West plans to utilize PISA, as applicable, for its planned renewable plant investments.

In July 2025, the MPSC approved the non-unanimous stipulation and agreement for the natural gas plant investments granting Evergy Missouri West's CCN and establishing that Evergy Missouri West's planned

investments in the natural gas plants are decisionally prudent. Evergy Missouri West intends to utilize the SB 4 CWIP inclusion provision and PISA, as applicable, for its planned investments in the natural gas plants.

FERC Proceedings
In October of each year, Evergy Kansas Central and Evergy Metro post an updated TFR that includes projected transmission capital expenditures and operating costs for the following year. This rate is the most significant component in the retail rate calculation for Evergy Kansas Central's and Evergy Metro's annual request with the KCC to adjust retail prices to include updated transmission costs through the TDC.

Evergy Kansas Central TFR Annual Update
Most recently, the updated TFR was expected to adjust Evergy Kansas Central's annual transmission revenues by approximately:

- $21.6 million increase effective in January 2026;
- $19.1 million increase effective in January 2025; and
- $115.8 million increase effective in January 2024.

Evergy Kansas Central TFR Formal Complaint
In February 2023, certain Evergy Kansas Central TFR customers submitted a formal complaint with FERC requesting the refund of over-collections related to the capital structure calculation in determining Evergy Kansas Central's Annual Transmission Revenue Requirement for the 2018 and 2019 rate years. As of December 31, 2025, and December 31, 2024, Evergy and Evergy Kansas Central had recorded a regulatory liability of $9.7 million and $7.1 million, respectively, related to the 2018 and 2019 rate year refund request. Evergy and Evergy Kansas Central are awaiting a response from FERC.

Evergy Metro TFR Annual Update
Most recently, the updated TFR was expected to adjust Evergy Metro's annual transmission revenues by approximately:

- $2.4 million decrease effective in January 2026;
- $1.0 million increase effective in January 2025; and
- $23.7 million increase effective in January 2024.

Regulatory Assets and Liabilities
The Evergy Companies have recorded assets and liabilities on their consolidated balance sheets resulting from the effects of the ratemaking process, which would not otherwise be recorded if they were not regulated. Regulatory assets represent incurred costs that are probable of recovery from future revenues. Regulatory liabilities represent future reductions in revenues or refunds to customers.

Management regularly assesses whether regulatory assets and liabilities are probable of future recovery or refund by considering factors such as decisions by the MPSC, KCC or FERC in Evergy Kansas Central's, Evergy Metro's and Evergy Missouri West's rate case filings; decisions in other regulatory proceedings, including decisions related to other companies that establish precedent on matters applicable to the Evergy Companies; and changes in laws and regulations. If recovery or refund of regulatory assets or liabilities is not approved by regulators or is no longer deemed probable, these regulatory assets or liabilities are recognized in the current period results of operations. The Evergy Companies continued ability to meet the criteria for recording regulatory assets and liabilities may be affected in the future by restructuring and deregulation in the electric industry or changes in accounting rules. In the event that the criteria no longer applied to any or all of the Evergy Companies' operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory recovery mechanism were provided. Additionally, these factors could result in an impairment on utility plant assets.

The Evergy Companies' regulatory assets and liabilities are detailed in the following tables.

	December 31					
	2025			2024		
	Evergy	Evergy Kansas Central	Evergy Metro	Evergy	Evergy Kansas Central	Evergy Metro
Regulatory Assets			(millions)			
Pension and post-retirement costs	$ 41.0	$ —	$ —	$ 47.3	$ —	$ —
Debt reacquisition costs	68.6	64.3	4.2	74.8	69.8	4.7
Debt fair value adjustment	76.1	—	—	81.6	—	—
Asset retirement obligations fair value adjustment	122.8	—	—	121.9	—	—
Depreciation	367.1	107.8	158.7	238.3	55.6	94.7
Cost of removal	394.1	151.8	186.4	332.1	133.5	167.8
Asset retirement obligations	220.4	94.8	97.3	189.0	81.5	82.2
Analog meter unrecovered investment	4.1	4.1	—	6.2	6.2	—
Treasury yield hedges	15.9	15.9	—	17.0	17.0	—
Iatan No. 1 and common facilities	5.3	—	2.4	5.6	—	2.5
Iatan No. 2 construction accounting costs	22.0	—	11.0	22.7	—	11.4
Property taxes	40.2	4.5	32.7	26.6	—	23.7
Disallowed plant costs	12.7	12.7	—	13.2	13.2	—
La Cygne environmental costs	6.4	4.7	1.7	7.7	5.8	1.9
Deferred customer programs	50.5	31.0	18.4	38.5	15.9	17.2
Fuel recovery mechanisms	64.6	11.8	11.6	25.7	16.3	9.4
February 2021 winter weather event	—	—	—	8.3	8.3	—
February 2021 winter weather event securitized costs	294.6	—	—	310.4	—	—
Solar rebates	—	—	—	3.4	—	—
Transmission delivery charge	14.2	13.2	1.0	22.0	20.0	2.0
Wolf Creek outage	26.0	13.0	13.0	14.6	7.3	7.3
Pension and other post-retirement benefit non-service costs	79.0	30.5	29.7	82.4	31.0	31.9
Retired generation facilities	102.6	—	—	120.8	—	—
Merger transition costs	13.7	6.4	5.1	18.4	8.7	6.9
Other regulatory assets	60.8	34.0	8.0	71.7	36.2	8.5
Total	2,102.7	600.5	581.2	1,900.2	526.3	472.1
Less: current portion	(217.4)	(76.7)	(42.6)	(180.9)	(79.7)	(42.7)
Total noncurrent regulatory assets	$ 1,885.3	$ 523.8	$ 538.6	$ 1,719.3	$ 446.6	$ 429.4

	December 31					
	2025			2024		
	Evergy	Evergy Kansas Central	Evergy Metro	Evergy	Evergy Kansas Central	Evergy Metro
Regulatory Liabilities			(millions)			
Taxes refundable through future rates	$ 1,581.6	$ 991.0	$ 470.4	$ 1,631.4	$ 1,008.5	$ 477.7
Nuclear production tax credits	263.1	130.5	132.6	168.6	82.4	86.2
Deferred regulatory gain from sale leaseback	20.6	20.6	—	26.1	26.1	—
Emission allowances	26.2	—	26.2	30.2	—	30.2
Nuclear decommissioning	480.4	173.3	307.1	387.2	142.1	245.1
Pension and post-retirement costs	279.4	71.6	205.3	206.6	39.0	165.4
Jurisdictional allowance for funds used during construction	23.4	21.7	1.7	23.8	22.1	1.7
La Cygne leasehold dismantling costs	29.6	29.6	—	29.6	29.6	—
Kansas tax credits	—	—	—	8.4	8.4	—
Purchase power agreement	2.2	2.2	—	3.0	3.0	—
Fuel recovery mechanisms	8.3	—	8.3	21.5	—	0.2
February 2021 winter weather event	5.8	4.7	1.1	3.0	—	3.0
Sibley AAO	26.4	—	—	52.8	—	—
TFR refunds	9.7	9.7	—	7.1	7.1	—
COLI rate credits refund	35.2	35.2	—	64.4	64.4	—
Levelized rate recovery	96.2	96.2	—	65.0	65.0	—
Other regulatory liabilities	78.1	36.3	26.6	117.1	54.7	37.4
Total	2,966.2	1,622.6	1,179.3	2,845.8	1,552.4	1,046.9
Less: current portion	(141.6)	(64.7)	(38.0)	(173.8)	(76.6)	(38.5)
Total noncurrent regulatory liabilities	$ 2,824.6	$ 1,557.9	$ 1,141.3	$ 2,672.0	$ 1,475.8	$ 1,008.4

The following summarizes the nature and period of recovery for each of the regulatory assets listed in the table above.

Pension and post-retirement costs: Represent the difference between pension and post-retirement costs under GAAP and pension and post-retirement costs for ratemaking that will be recovered in future rates. Of this amount, as of December 31, 2025, $35.8 million is not included in rate base and is amortized over various periods.

Debt reacquisition costs: Includes costs incurred to reacquire and refinance debt. These costs are amortized over the term of the new debt or the remaining lives of the old debt issuances if no new debt was issued and are not included in rate base.

Debt fair value adjustment: Represents purchase accounting adjustments recorded to state the carrying value of Evergy Metro and Evergy Missouri West long-term debt at fair value in connection with the merger that created Evergy. Amount is amortized over the life of the related debt and is not included in rate base.

Asset retirement obligations fair value adjustment: Represents purchase accounting adjustments recorded to state the carrying value of Evergy Metro and Evergy Missouri West AROs at fair value in connection with the merger that created Evergy. Amount is amortized over the life of the related plant and is not included in rate base.

Depreciation: Represents depreciation and carrying costs deferred under PISA approved in Kansas and Missouri where depreciation incurred on assets placed in service prior to inclusion in rates can be deferred until the next general rate case and then amortized over a 20-year period and included in rate base.

Cost of removal: Represents amounts spent, but not yet collected, to dispose of plant assets. This asset will decrease as removal costs are collected in rates and is included in rate base.

Asset retirement obligations: Represents amounts associated with AROs as discussed further in Note 6. These amounts are recovered over the life of the related plant and are not included in rate base.

Analog meter unrecovered investment: Represents the deferral of unrecovered investment of retired analog meters. These costs are not included in rate base and are amortized through 2028.

Treasury yield hedges: Represents the effective portion of treasury yield hedge transactions. Amortization of this amount will be included in interest expense over the term of the related debt and is not included in rate base.

Iatan No. 1 and common facilities: Represents depreciation and carrying costs related to Iatan No. 1 and common facilities. These costs are included in rate base and amortized through 2057.

Iatan No. 2 construction accounting costs: Represents the construction accounting costs related to Iatan No. 2. These costs are included in rate base and amortized through 2059.

Property taxes: Represents actual costs incurred for property taxes in excess of amounts collected in revenues. These costs are expected to be recovered over various periods and are not included in rate base.

Disallowed plant costs: The KCC originally disallowed certain costs related to the Wolf Creek plant. In 1987, the KCC revised its original conclusion and provided for recovery of an indirect disallowance with no return on investment. This regulatory asset represents the present value of the future expected revenues to be provided to recover these costs, net of the amounts amortized.

La Cygne environmental costs: Represents the deferral of depreciation and amortization expense and associated carrying charges related to the La Cygne Station environmental project. This amount will be amortized over the life of the related asset and is included in rate base.

Deferred customer programs: Represents costs related to various energy efficiency programs that have been accumulated and deferred for future recovery. These amounts are not included in rate base and are amortized over various periods.

Fuel recovery mechanisms: Represents the actual cost of fuel consumed in producing electricity and the cost of purchased power in excess of the amounts collected from customers. This difference is expected to be recovered over a one-year period and is not included in rate base.

February 2021 winter weather event: Represents deferred extraordinary fuel and purchased power costs incurred to provide electric service as a result of the February 2021 winter weather event. These amounts are not included in rate base and were fully amortized in 2025.

February 2021 winter weather event securitized costs: Represents deferred extraordinary fuel and purchased power costs incurred to provide electric service as a result of the February 2021 winter weather event. In February 2024, Evergy Missouri West securitized this asset. Evergy Missouri West expects to recover the amounts through 2038.

Solar rebates: Represents costs associated with solar rebates provided to retail electric customers. These amounts are not included in rate base and were fully amortized in 2025.

Transmission delivery charge: Represents costs associated with the transmission delivery charge. The amounts are not included in rate base and are amortized over a one-year period.

Wolf Creek outage: Represents deferred expenses associated with Wolf Creek's scheduled refueling and maintenance outages. These expenses are amortized during the period between planned outages and are not included in rate base.

Pension and other post-retirement benefit non-service costs: Represents the non-service component of pension and post-retirement net benefit costs that are capitalized as authorized by regulators. The amounts are included in rate base and are recovered over the life of the related asset.

Retired generation facilities: Represents amounts to be recovered for facilities that have been retired, are not included in rate base and recovered through 2030.

Merger transition costs: Represents recoverable transition costs related to the merger that created Evergy. The amounts are not included in rate base and are recovered through 2028.

Other regulatory assets: Includes various regulatory assets that individually are small in relation to the total regulatory asset balance. Of these amounts, $5.5 million, $4.9 million and $0.3 million for Evergy, Evergy Kansas Central and Evergy Metro, respectively, are included in rate base and are amortized over various periods.

The following summarizes the nature and period of amortization for each of the regulatory liabilities listed in the table above.

Taxes refundable through future rates: Represents the obligation to return to customers income taxes recovered in earlier periods when corporate income tax rates were higher than current income tax rates. A large portion of this amount is related to depreciation and will be refunded to customers over the life of the applicable property.

Nuclear production tax credits: Represents nuclear production tax credits (PTCs) generated by Wolf Creek. The benefits from these credits are expected to be refunded to customers in future rates following the monetization of the credits.

Deferred regulatory gain from sale leaseback: Represents the gain Evergy Kansas South recorded on the 1987 sale and leaseback of its 50% interest in La Cygne Unit 2. The gain is amortized over the term of the lease.

Emission allowances: Represents deferred gains related to the sale of emission allowances to be refunded to customers.

Nuclear decommissioning: Represents the difference between the fair value of the assets held in the nuclear decommissioning trust and the amount recorded for the accumulated accretion and depreciation expense associated with the asset retirement obligation related to Wolf Creek.

Pension and post-retirement costs: Represents the difference between pension and post-retirement costs under GAAP, including accumulated unrecognized gains, and pension and post-retirement costs for ratemaking that will be refunded in future rates.

Jurisdictional allowance for funds used during construction: Represents AFUDC that is accrued subsequent to the time the associated construction charges are included in prices and prior to the time the related assets are placed in service. The AFUDC is amortized to depreciation expense over the useful life of the asset that is placed in service.

La Cygne leasehold dismantling costs: Represents amounts collected but not yet spent on the contractual obligation to dismantle a portion of La Cygne Unit 2. The obligation will be discharged as the unit is dismantled.

Kansas tax credits: Represents Kansas tax credits on investment in utility plant. Amounts will be credited to customers subsequent to the realization of the credits over the remaining lives of the utility plant giving rise to the tax credits.

Purchase power agreement: Represents the amount included in retail electric rates from customers in excess of costs incurred under purchase power agreements. Amounts are amortized over a five-year period.

Fuel recovery mechanisms: Represents the amount collected from customers in excess of the actual cost of fuel consumed in producing electricity and the cost of purchased power. This difference is expected to be refunded over a one-year period.

February 2021 winter weather event: Represents refunds to customers related to a February 2021 winter weather event.

Sibley accounting authority order: These amounts were collected in connection with an accounting authority order (AAO) granted by the MPSC in October 2019 and represent revenues that Evergy Missouri West collected from customers for the return on its unrecovered investment in Sibley Station, non-fuel operations and maintenance costs and other costs associated with Sibley Station following its retirement in November 2018. The amended final order in Evergy Missouri West's 2022 rate case required Evergy Missouri West to refund these revenues to customers over a four-year period.

TFR refunds: These amounts are associated with a formal complaint certain Evergy Kansas Central TFR customers submitted with FERC requesting the refund of over-collections related to the capital structure calculation

in determining Evergy Kansas Central's Annual Transmission Revenue Requirement for the 2018 and 2019 rate years. See "Evergy Kansas Central TFR Formal Complaint" within this Note 4 for additional information.

COLI rate credits refund: Represents the amount ordered to be refunded by Evergy Kansas Central to customers and will be amortized through 2027, to account for the difference between the expected amount of COLI rate credits approved and the actual amount of COLI rate credits received by customers from 1987 through 2023.

Levelized rate recovery: Instead of traditional ratemaking, the KCC ordered that Evergy Kansas Central recover the costs of several owned wind farms through a levelized revenue requirement. The levelized recovery of costs defers the rates intended to recover allowable costs for each wind farm beyond the period in which those costs would be charged to expense under traditional ratemaking. The regulatory liability represents the cumulative amount collected in accordance with the ordered ratemaking treatment in excess of the amount that would have been collected under traditional ratemaking.

Other regulatory liabilities: Includes various regulatory liabilities that individually are relatively small in relation to the total regulatory liability balance. These amounts will be credited over various periods.

5. GOODWILL

GAAP requires goodwill to be tested for impairment annually and when an event occurs indicating the possibility that an impairment exists. Evergy's impairment test for the $2,336.6 million of goodwill that was recorded as a result of the merger that created Evergy was conducted as of May 1, 2025. The goodwill impairment test consists of comparing the fair value of a reporting unit to its carrying amount, including goodwill, to identify potential impairment. In the event that the carrying amount exceeds the fair value of the reporting unit, an impairment loss is recognized for the difference between the carrying amount of the reporting unit and its fair value. Evergy's consolidated operations are considered one reporting unit for assessment of impairment, as management assesses financial performance and allocates resources on a consolidated basis. The determination of fair value of the reporting unit consisted of two valuation techniques: an income approach consisting of a discounted cash flow analysis and a market approach consisting of a determination of reporting unit invested capital using a market multiple derived from the historical earnings before interest, income taxes, depreciation and amortization and market prices of the stock of peer companies. The results of the two techniques were evaluated and weighted to determine a point within the range that management considered representative of fair value for the reporting unit. The fair value of the reporting unit exceeded the carrying amount, including goodwill. As a result, there was no impairment of goodwill in 2025 or 2024.

6. ASSET RETIREMENT OBLIGATIONS

AROs associated with tangible long-lived assets are legal obligations that exist under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel. These liabilities are recognized at estimated fair value as incurred with a corresponding amount capitalized as part of the cost of the related long-lived assets and depreciated over their useful lives. Accretion of the liabilities due to the passage of time is recorded to a regulatory asset and/or liability. Changes in the estimated fair values of the liabilities are recognized when known.

Evergy Kansas Central, Evergy Metro and Evergy Missouri West have AROs related to asbestos abatement and the closure and post-closure care of ponds and landfills containing coal combustion residuals (CCRs). In addition, Evergy Kansas Central and Evergy Metro have AROs related to decommissioning Wolf Creek and the retirement of wind generation facilities.

The following table summarizes the change in the Evergy Companies' AROs for the periods ending December 31, 2025 and 2024.

	Evergy		Evergy Kansas Central		Evergy Metro	
	2025	2024	2025	2024	2025	2024
	(millions)					
Beginning balance January 1	$ 1,297.0	$ 1,203.1	$ 647.8	$ 599.3	$ 502.7	$ 460.4
Additions	—	72.8	—	44.8	—	24.1
Revision in timing and/or estimates	(5.3)	(28.0)	(5.3)	(24.3)	—	(0.5)
Settlements	(13.3)	(12.1)	(7.8)	(7.4)	(5.3)	(4.3)
Accretion	63.9	61.2	37.6	35.4	24.1	23.0
Ending balance	$ 1,342.3	$ 1,297.0	$ 672.3	$ 647.8	$ 521.5	$ 502.7
Less: current portion	(34.2)	(28.7)	(18.3)	(16.5)	(15.0)	(11.8)
Total noncurrent asset retirement obligation	$ 1,308.1	$ 1,268.3	$ 654.0	$ 631.3	$ 506.5	$ 490.9

In 2024, Evergy, Evergy Kansas Central and Evergy Metro recorded $72.8 million, $44.8 million and $24.1 million of ARO liabilities, respectively, related to the new Environmental Protection Agency (EPA) CCR regulation focused on legacy surface impoundments and historic placements of CCR. This regulation expands applicability of the 2015 CCR regulation to inactive landfills and beneficial use sites not previously regulated. The Evergy Companies recorded an offsetting balance to property, plant and equipment, net, or a regulatory asset for each ARO liability. See Note 15 for additional information regarding the regulation of CCRs.

7. PROPERTY, PLANT AND EQUIPMENT

The following tables summarize the property, plant and equipment of Evergy, Evergy Kansas Central and Evergy Metro.

December 31, 2025	Evergy	Evergy Kansas Central	Evergy Metro
		(millions)	
Electric plant in service	$ 38,218.9	$ 18,893.6	$ 14,001.3
Electric plant acquisition adjustment	739.8	724.9	—
Accumulated depreciation	(14,986.6)	(7,308.5)	(6,110.5)
Plant in service	23,972.1	12,310.0	7,890.8
Construction work in progress	2,120.6	1,045.8	453.6
Nuclear fuel, net	208.8	104.3	104.5
Net property, plant and equipment	$ 26,301.5	$ 13,460.1	$ 8,448.9

December 31, 2024	Evergy	Evergy Kansas Central	Evergy Metro
		(millions)	
Electric plant in service	$ 36,444.9	$ 17,914.9	$ 13,468.3
Electric plant acquisition adjustment	742.9	724.9	—
Accumulated depreciation	(14,165.5)	(6,914.4)	(5,752.6)
Plant in service	23,022.3	11,725.4	7,715.7
Construction work in progress	1,707.0	1,053.7	476.1
Nuclear fuel, net	200.9	100.3	100.6
Plant to be retired, net[(a)]	0.7	0.7	—
Net property, plant and equipment	$ 24,930.9	$ 12,880.1	$ 8,292.4

[(a)] As of December 31, 2024, represents the planned retirement of Evergy Kansas Central analog meters prior to the end of their remaining useful lives.

The following table summarizes the property, plant and equipment of the VIE for Evergy and Evergy Kansas Central.

	December 31	
	2025	2024
	(millions)	
Electric plant of VIEs	$ 392.1	$ 392.1
Accumulated depreciation of VIEs	(272.7)	(265.6)
Net property, plant and equipment of VIEs	$ 119.4	$ 126.5

Depreciation Expense

The Evergy Companies' depreciation expense is detailed in the following table.

	2025	2024	2023
		(millions)	
Evergy[a]	$ 944.2	$ 965.9	$ 943.3
Evergy Kansas Central[a]	512.2	542.3	497.7
Evergy Metro	283.3	294.6	319.7

[a] Approximately $7.1 million of depreciation expense in each of 2025, 2024 and 2023 was attributable to property, plant and equipment of VIEs.

8. JOINTLY-OWNED ELECTRIC UTILITY PLANTS

Evergy's, Evergy Kansas Central's and Evergy Metro's share of jointly-owned electric utility plants at December 31, 2025, are detailed in the following tables.

Evergy

	Evergy's share	Electric plant in service	Accumulated depreciation	Nuclear fuel, net	Construction work in progress	2026 accredited capacity-MWs
			(millions, except MW amounts)			
Wolf Creek Unit	94 %	$ 4,444.6	$ 2,395.8	$ 208.8	$ 291.6	1,106
La Cygne Units[a]	100 %	2,425.9	1,161.9	—	35.9	1,426
Iatan No. 1 Unit	88 %	830.4	333.5	—	7.5	618
Iatan No. 2 Unit	73 %	1,433.8	519.2	—	2.8	653
Iatan Common	79 %	524.3	157.3	—	9.2	n/a
Jeffrey Energy Center	100 %	2,764.7	1,177.6	—	71.2	2,183
State Line	40 %	140.3	107.6	—	5.6	211
Dogwood Energy Center	22 %	90.6	49.6	—	7.1	145
Sumner County CCGT Facility[b]	100 %	—	—	—	201.0	n/a
Reno County CCGT Facility[b]	100 %	—	—	—	166.2	n/a

[a] The VIE consolidated by Evergy and Evergy Kansas Central holds its 50% leasehold interest in La Cygne Unit 2. This 50% leasehold interest in La Cygne Unit 2 is reflected in the information provided above. See Note 19 for additional information.

[b] Combined-cycle natural gas plants currently under construction in Kansas, jointly-owned by Evergy Kansas Central and Evergy Missouri West. See Note 1, Natural Gas Plant Investments for additional information.

Evergy Kansas Central

	Evergy Kansas Central's share	Electric plant in service	Accumulated depreciation	Nuclear fuel, net	Construction work in progress	2026 accredited capacity-MWs
			(millions, except MW amounts)			
Wolf Creek Unit	47 %	$ 2,169.2	$ 1,165.8	$ 104.3	$ 138.0	553
La Cygne Units[a]	50 %	1,162.0	620.0	—	19.5	713
Jeffrey Energy Center	92 %	2,530.7	1,075.7	—	65.5	2,008
State Line	40 %	140.3	107.6	—	5.6	211
Sumner County CCGT Facility[b]	50 %	—	—	—	100.7	n/a
Reno County CCGT Facility[b]	50 %	—	—	—	84.5	n/a

[a] The VIE consolidated by Evergy and Evergy Kansas Central holds its 50% leasehold interest in La Cygne Unit 2. This 50% leasehold interest in La Cygne Unit 2 is reflected in the information provided above. See Note 19 for additional information.

[b] Combined-cycle natural gas plants currently under construction in Kansas, jointly-owned by Evergy Kansas Central and Evergy Missouri West. See Note 1, Natural Gas Plant Investments for additional information.

Evergy Metro

	Evergy Metro's share	Electric plant in service	Accumulated depreciation	Nuclear fuel, net	Construction work in progress	2026 accredited capacity-MWs
			(millions, except MW amounts)			
Wolf Creek Unit	47 %	$ 2,275.4	$ 1,230.0	$ 104.5	$ 153.6	553
La Cygne Units	50 %	1,263.9	541.9	—	16.4	713
Iatan No. 1 Unit	70 %	646.0	277.1	—	6.0	492
Iatan No. 2 Unit	55 %	1,081.9	471.9	—	2.1	491
Iatan Common	61 %	416.0	140.2	—	6.9	n/a

Each owner must fund its own portion of the plant's operating expenses and capital expenditures. The Evergy Companies' share of direct expenses are included in the appropriate operating expense classifications in Evergy's, Evergy Kansas Central's and Evergy Metro's consolidated financial statements.

9. PENSION PLANS AND POST-RETIREMENT BENEFITS

Evergy and certain of its subsidiaries maintain, and Evergy Kansas Central and Evergy Metro participate in, qualified non-contributory defined benefit pension plans covering the majority of Evergy Kansas Central's and Evergy Metro's employees as well as certain non-qualified plans covering certain active and retired officers.

For the majority of employees, pension benefits under these plans reflect the employees' compensation, years of service and age at retirement. However, for the plan covering Evergy Kansas Central's employees, the benefits for non-union employees hired between 2002 and the second quarter of 2018 and union employees hired beginning in 2012 are derived from a cash balance account formula. The plan was closed to future non-union employees in 2018. For the plans covering Evergy Metro's employees, the benefits for union employees hired beginning in 2014 are derived from a cash balance account formula and the plans were closed to future non-union employees in 2014.

Evergy and its subsidiaries also provide certain post-retirement health care and life insurance benefits for substantially all retired employees of Evergy Kansas Central and Evergy Metro and their respective shares of Wolf Creek's post-retirement benefit plans.

The Evergy Companies record pension and post-retirement expense in accordance with rate orders from the KCC and MPSC that allow the difference between pension and post-retirement costs under GAAP and costs for

ratemaking to be recognized as a regulatory asset or liability. This difference between financial and regulatory accounting methods is due to timing and will be eliminated over the life of the plans.

For 2025, Evergy, Evergy Kansas Central and Evergy Metro recorded net pension settlement (gains) and special termination benefit expense of $7.6 million, $2.2 million and $5.4 million, respectively. For 2025, Evergy, Evergy Kansas Central and Evergy Metro recorded net post-retirement settlement (gains) and special termination benefit expense of $(6.4) million, $(3.5) million and $(2.9) million, respectively. For 2024, Evergy and Evergy Kansas Central recorded pension special termination benefit expense of $0.2 million. For 2023, Evergy, Evergy Kansas Central and Evergy Metro recorded pension settlement (gains) and losses of $(21.1) million, $1.1 million and $(22.2) million, respectively. These settlement (gains) and losses and special termination benefits were the result of accelerated distributions and enhanced pension distributions as a result of employee retirements for certain plan participants, as well as the sale of certain life insurance liabilities. Evergy, Evergy Kansas Central and Evergy Metro deferred substantially all of the (gains), losses and expense to regulatory assets or regulatory liabilities and expect to recover these amounts over future periods pursuant to regulatory agreements.

The following pension benefits tables provide information relating to the funded status of all defined benefit pension plans on an aggregate basis as well as the components of net periodic benefit costs. For financial reporting purposes, the market value of plan assets is the fair value. Net periodic benefit costs reflect total plan benefit costs prior to the effects of capitalization and sharing with joint owners of power plants.

Evergy

	Pension Benefits		Post-Retirement Benefits	
	2025	**2024**	**2025**	**2024**
Change in projected benefit obligation (PBO)		(millions)		
PBO as of January 1	$ 1,665.0	$ 1,704.4	$ 180.9	$ 192.8
Service cost	45.2	46.0	1.5	1.6
Interest cost	94.2	89.5	9.5	10.1
Contribution by participants	—	—	2.6	5.6
Plan amendments	—	—	0.1	4.2
Actuarial (gain) loss	14.2	(60.7)	7.3	(13.0)
Benefits paid	(119.1)	(106.4)	(16.5)	(20.4)
Settlements	(0.7)	—	(38.7)	—
Special termination benefits	8.3	0.2	3.9	—
Other	(8.7)	(8.0)	—	—
PBO as of December 31	$ 1,698.4	$ 1,665.0	$ 150.6	$ 180.9
Change in plan assets				
Fair value of plan assets as of January 1	$ 1,299.4	$ 1,250.7	$ 203.0	$ 201.5
Actual return on plan assets	185.8	122.2	21.1	14.2
Contributions by employer and participants	66.0	37.2	2.8	6.4
Benefits paid	(115.4)	(102.7)	(15.4)	(19.1)
Settlements	—	—	(38.7)	—
Other	(8.7)	(8.0)	—	—
Fair value of plan assets as of December 31	$ 1,427.1	$ 1,299.4	$ 172.8	$ 203.0
Funded status as of December 31	$ (271.3)	$ (365.6)	$ 22.2	$ 22.1

Evergy

	Pension Benefits		Post-Retirement Benefits	
	2025	2024	2025	2024
Amounts recognized in the consolidated balance sheet		(millions)		
Non-current asset	$ —	$ —	$ 35.0	$ 33.9
Current pension and other post-retirement liability	(4.4)	(5.0)	(1.0)	(1.1)
Noncurrent pension liability and other post-retirement liability	(266.9)	(360.6)	(11.8)	(10.7)
Net amount recognized before regulatory treatment	(271.3)	(365.6)	22.2	22.1
Accumulated OCI or regulatory asset/liability	(239.7)	(173.2)	(31.3)	(41.7)
Net amount recognized as of December 31	$ (511.0)	$ (538.8)	$ (9.1)	$ (19.6)
Amounts in accumulated OCI or regulatory asset/liability not yet recognized as a component of net periodic benefit cost:				
Actuarial gain	$ (247.6)	$ (183.0)	$ (35.8)	$ (46.5)
Prior service cost	7.9	9.8	4.5	4.8
Net amount recognized as of December 31	$ (239.7)	$ (173.2)	$ (31.3)	$ (41.7)

Evergy Kansas Central

	Pension Benefits		Post-Retirement Benefits	
	2025	2024	2025	2024
Change in projected benefit obligation (PBO)		(millions)		
PBO as of January 1	$ 851.0	$ 876.2	$ 93.3	$ 97.8
Service cost	18.5	19.0	0.9	0.9
Interest cost	47.7	45.6	4.9	5.1
Contribution by participants	—	—	0.3	0.7
Plan amendments	—	—	—	3.3
Actuarial (gain) loss	6.8	(28.2)	2.4	(5.3)
Benefits paid	(67.3)	(58.3)	(7.6)	(9.2)
Settlements	—	—	(21.0)	—
Special termination benefits	2.2	0.2	1.6	—
Other	(3.9)	(3.5)	—	—
PBO as of December 31	$ 855.0	$ 851.0	$ 74.8	$ 93.3
Change in plan assets				
Fair value of plan assets as of January 1	$ 633.9	$ 620.6	$ 99.1	$ 99.1
Actual return on plan assets	89.9	62.3	11.2	7.6
Contributions by employer and participants	29.8	10.6	0.4	1.2
Benefits paid	(65.2)	(56.1)	(7.3)	(8.8)
Settlements	—	—	(21.0)	—
Other	(3.9)	(3.5)	—	—
Fair value of plan assets as of December 31	$ 684.5	$ 633.9	$ 82.4	$ 99.1
Funded status as of December 31	$ (170.5)	$ (217.1)	$ 7.6	$ 5.8

Evergy Kansas Central

	Pension Benefits		Post-Retirement Benefits	
	2025	2024	2025	2024
Amounts recognized in the consolidated balance sheet		(millions)		
Non-current asset	$ —	$ —	$ 11.7	$ 9.8
Current pension and other post-retirement liability	(2.4)	(2.4)	(0.5)	(0.5)
Noncurrent pension liability and other post-retirement liability	(168.1)	(214.7)	(3.6)	(3.5)
Net amount recognized before regulatory treatment	(170.5)	(217.1)	7.6	5.8
Accumulated OCI or regulatory asset/liability	(31.4)	10.2	(17.1)	(20.3)
Net amount recognized as of December 31	$ (201.9)	$ (206.9)	$ (9.5)	$ (14.5)
Amounts in accumulated OCI or regulatory asset/liability not yet recognized as a component of net periodic benefit cost:				
Actuarial gain	(40.8)	(1.2)	$ (20.4)	$ (23.9)
Prior service cost	9.4	11.4	3.3	3.6
Net amount recognized as of December 31	$ (31.4)	$ 10.2	$ (17.1)	$ (20.3)

Evergy Metro

	Pension Benefits		Post-Retirement Benefits	
	2025	2024	2025	2024
Change in projected benefit obligation (PBO)		(millions)		
PBO as of January 1	$ 796.3	$ 809.7	$ 87.6	$ 95.0
Service cost	26.7	27.0	0.6	0.7
Interest cost	45.6	43.0	4.6	5.0
Contribution by participants	—	—	2.3	4.9
Plan amendments	—	—	0.1	0.9
Actuarial (gain) loss	7.4	(31.9)	4.9	(7.7)
Benefits paid	(50.4)	(47.0)	(8.9)	(11.2)
Settlements	(0.7)	—	(17.7)	—
Special termination benefits	6.1	—	2.3	—
Other	(4.8)	(4.5)	—	—
PBO as of December 31	$ 826.2	$ 796.3	$ 75.8	$ 87.6
Change in plan assets				
Fair value of plan assets as of January 1	$ 665.5	$ 630.1	$ 103.9	$ 102.4
Actual return on plan assets	95.9	59.9	9.9	6.6
Contributions by employer and participants	36.2	26.6	2.4	5.2
Benefits paid	(50.2)	(46.6)	(8.1)	(10.3)
Settlements	—	—	(17.7)	—
Other	(4.8)	(4.5)	—	—
Fair value of plan assets as of December 31	$ 742.6	$ 665.5	$ 90.4	$ 103.9
Funded status as of December 31	$ (83.6)	$ (130.8)	$ 14.6	$ 16.3

Evergy Metro

	Pension Benefits		Post-Retirement Benefits	
	2025	2024	2025	2024
Amounts recognized in the consolidated balance sheet		(millions)		
Non-current asset	$ —	$ —	$ 23.3	$ 24.1
Current pension and other post-retirement liability	(0.4)	(1.1)	(0.5)	(0.5)
Noncurrent pension liability and other post-retirement liability	(83.2)	(129.7)	(8.2)	(7.3)
Net amount recognized before regulatory treatment	(83.6)	(130.8)	14.6	16.3
Accumulated OCI or regulatory asset/liability	(200.2)	(174.7)	(19.8)	(27.3)
Net amount recognized as of December 31	$ (283.8)	$ (305.5)	$ (5.2)	$ (11.0)
Amounts in accumulated OCI or regulatory asset/liability not yet recognized as a component of net periodic benefit cost:				
Actuarial gain	$ (198.9)	$ (173.4)	$ (16.7)	$ (23.8)
Prior service cost	(1.3)	(1.3)	(3.1)	(3.5)
Net amount recognized as of December 31	$ (200.2)	$ (174.7)	$ (19.8)	$ (27.3)

Actuarial gains for the Evergy Companies' pension benefit plans for 2024 were primarily driven by an increase in the discount rate used to measure the benefit obligation as a result of higher market interest rates. See the weighted average assumptions used to determine the benefit obligations within this Note 9 for further information.

As of December 31, 2025 and 2024, Evergy's pension benefits include non-qualified benefit obligations of $35.4 million and $36.0 million, respectively, which are funded by trusts containing assets of $31.2 million and $31.4 million, respectively. As of December 31, 2025 and 2024, Evergy Kansas Central's pension benefits include non-qualified benefit obligations of $18.2 million and $18.4 million, respectively, which are funded by trusts containing assets of $23.5 million and $23.4 million, respectively. The assets in the aforementioned trusts are not included in the table above. See Note 14 for more information on these amounts.

Evergy

	Pension Benefits			Post-Retirement Benefits		
	2025	2024	2023	2025	2024	2023
Components of net periodic benefit costs			(millions)			
Service cost	$ 45.2	$ 46.0	$ 44.9	$ 1.5	$ 1.6	$ 1.8
Interest cost	94.2	89.5	91.9	9.5	10.1	11.1
Expected return on plan assets	(88.0)	(86.7)	(87.6)	(10.3)	(11.5)	(11.9)
Prior service cost	1.9	1.9	1.9	0.4	0.1	0.1
Recognized net actuarial gain	(18.4)	(17.4)	(21.5)	(3.9)	(3.9)	(4.2)
Settlements and special termination benefits	7.6	0.2	(21.1)	(6.4)	—	—
Net periodic benefit costs before regulatory adjustment and intercompany allocations	42.5	33.5	8.5	(9.2)	(3.6)	(3.1)
Regulatory adjustment	11.8	24.1	94.0	3.3	(0.1)	(0.1)
Intercompany allocations	n/a	n/a	n/a	n/a	n/a	n/a
Net periodic benefit costs (income)	54.3	57.6	102.5	(5.9)	(3.7)	(3.2)
Other changes in plan assets and benefit obligations recognized in OCI or regulatory assets/liabilities						
Current year net (gain) loss	(83.7)	(96.3)	7.1	(3.5)	(15.7)	(13.6)
Amortization of gain	18.4	17.4	21.5	3.9	3.9	4.2
Prior service cost	—	—	—	0.1	4.2	—
Amortization of prior service cost	(1.9)	(1.9)	(1.9)	(0.4)	(0.1)	(0.1)
Net gain due to settlement	0.7	—	21.1	10.3	—	—
Total recognized in OCI or regulatory asset/liability	(66.5)	(80.8)	47.8	10.4	(7.7)	(9.5)
Total recognized in net periodic benefit costs and OCI or regulatory asset/liability	$ (12.2)	$ (23.2)	$ 150.3	$ 4.5	$ (11.4)	$ (12.7)

Evergy Kansas Central

	Pension Benefits			Post-Retirement Benefits		
	2025	2024	2023	2025	2024	2023
Components of net periodic benefit costs			(millions)			
Service cost	$ 18.5	$ 19.0	$ 18.6	$ 0.9	$ 0.9	$ 0.9
Interest cost	47.7	45.6	47.0	4.9	5.1	5.7
Expected return on plan assets	(42.9)	(43.0)	(44.1)	(5.2)	(5.9)	(6.3)
Prior service cost	2.0	1.9	2.0	0.3	0.1	—
Recognized net actuarial (gain) loss	(0.5)	0.9	(2.5)	(2.0)	(2.0)	(2.0)
Settlements and special termination benefits	2.2	0.2	1.1	(3.5)	—	—
Net periodic benefit costs before regulatory adjustment and intercompany allocations	27.0	24.6	22.1	(4.6)	(1.8)	(1.7)
Regulatory adjustment	(7.8)	(6.4)	30.4	2.2	0.8	(1.7)
Intercompany allocations	(3.0)	(1.9)	(2.3)	(0.1)	(0.1)	0.3
Net periodic benefit costs (income)	16.2	16.3	50.2	(2.5)	(1.1)	(3.1)
Other changes in plan assets and benefit obligations recognized in OCI or regulatory assets/liabilities						
Current year net (gain) loss	(40.1)	(47.7)	11.0	(3.6)	(7.0)	(7.8)
Amortization of gain (loss)	0.5	(0.9)	2.5	2.0	2.0	2.0
Prior service cost	—	—	—	0.1	3.4	—
Amortization of prior service cost	(2.0)	(1.9)	(2.0)	(0.3)	(0.1)	—
Net gain (loss) due to settlement	—	—	(1.1)	5.0	—	—
Total recognized in OCI or regulatory asset/liability	(41.6)	(50.5)	10.4	3.2	(1.7)	(5.8)
Total recognized in net periodic benefit costs and OCI or regulatory asset/liability	$ (25.4)	$ (34.2)	$ 60.6	$ 0.7	$ (2.8)	$ (8.9)

Evergy Metro

	Pension Benefits			Post-Retirement Benefits		
	2025	2024	2023	2025	2024	2023
Components of net periodic benefit costs			(millions)			
Service cost	$ 26.7	$ 27.0	$ 26.3	$ 0.6	$ 0.7	$ 0.9
Interest cost	45.6	43.0	44.0	4.6	5.0	5.5
Expected return on plan assets	(45.0)	(43.7)	(43.4)	(5.1)	(5.6)	(5.7)
Prior service cost	—	—	—	(0.3)	(0.4)	(0.4)
Recognized net actuarial gain	(17.2)	(17.5)	(18.2)	(1.9)	(1.8)	(2.1)
Settlements and special termination benefits	5.4	—	(22.2)	(2.9)	—	—
Net periodic benefit costs before regulatory adjustment and intercompany allocations	15.5	8.8	(13.5)	(5.0)	(2.1)	(1.8)
Regulatory adjustment	19.0	29.8	63.0	1.5	(0.6)	2.1
Intercompany allocations	0.5	(2.2)	(1.1)	0.6	0.6	—
Net periodic benefit costs (income)	35.0	36.4	48.4	(2.9)	(2.1)	0.3
Other changes in plan assets and benefit obligations recognized in OCI or regulatory assets/liabilities						
Current year net gain	(43.4)	(48.1)	(4.2)	—	(8.7)	(5.8)
Amortization of gain	17.2	17.5	18.2	1.9	1.8	2.1
Prior service cost	—	—	—	0.1	0.9	—
Amortization of prior service cost	—	—	—	0.3	0.4	0.4
Net gain due to settlement	0.7	—	22.2	5.2	—	—
Total recognized in OCI or regulatory asset/liability	(25.5)	(30.6)	36.2	7.5	(5.6)	(3.3)
Total recognized in net periodic benefit costs and OCI or regulatory asset/liability	$ 9.5	$ 5.8	$ 84.6	$ 4.6	$ (7.7)	$ (3.0)

For financial reporting purposes, the estimated prior service cost and net actuarial (gain) loss for the defined benefit plans are amortized from accumulated other comprehensive income (OCI) or a regulatory asset/liability into net periodic benefit cost. The Evergy Companies amortize prior service cost on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan. The Evergy Companies amortize the net actuarial (gain) loss on a straight-line basis over the average future service of active plan participants benefiting under the plan without application of an amortization corridor.

Pension and other post-retirement benefit plans with the PBO, accumulated benefit obligation (ABO) or accumulated other post-retirement benefit obligation (APBO) in excess of the fair value of plan assets at year-end are detailed in the following tables.

December 31, 2025	Evergy	Evergy Kansas Central	Evergy Metro
		(millions)	
ABO for all defined benefit pension plans	$ 1,541.1	$ 793.0	$ 730.9
Pension plans with the PBO in excess of plan assets			
Projected benefit obligation	$ 1,698.4	$ 855.0	$ 826.2
Fair value of plan assets	1,427.1	684.5	742.6
Pension plans with the ABO in excess of plan assets			
Accumulated benefit obligation	$ 1,541.1	$ 793.0	$ 730.9
Fair value of plan assets	1,427.1	684.5	742.6
Other post-retirement benefit plans with the APBO in excess of plan assets			
Accumulated other post-retirement benefit obligation	$ 68.0	$ 3.9	$ 64.1
Fair value of plan assets	55.5	—	55.5

December 31, 2024	Evergy	Evergy Kansas Central	Evergy Metro
		(millions)	
ABO for all defined benefit pension plans	$ 1,503.6	$ 785.9	$ 700.2
Pension plans with the PBO in excess of plan assets			
Projected benefit obligation	$ 1,665.0	$ 851.0	$ 796.3
Fair value of plan assets	1,299.4	633.9	665.5
Pension plans with the ABO in excess of plan assets			
Accumulated benefit obligation	$ 1,503.6	$ 785.9	$ 700.2
Fair value of plan assets	1,299.4	633.9	665.5
Other post-retirement benefit plans with the APBO in excess of plan assets			
Accumulated other post-retirement benefit obligation	$ 78.8	$ 3.7	$ 75.1
Fair value of plan assets	67.3	—	67.3

The expected long-term rate of return on plan assets represents the Evergy Companies' estimate of the long-term return on plan assets and is based on historical and projected rates of return for current and planned asset classes in the plans' investment portfolios. Assumed projected rates of return for each asset class were selected after analyzing historical experience and future expectations of the returns of various asset classes. Based on the target asset allocation for each asset class, the overall expected rate of return for the portfolios was developed and adjusted for the effect of projected benefits paid from plan assets and future plan contributions.

The following tables provide the weighted-average assumptions used to determine benefit obligations and net costs for the Evergy Companies' pension and post-retirement benefit plans.

	Pension Benefits			Post-Retirement Benefits		
Weighted-average assumptions used to determine the benefit obligation at December 31, 2025	**Evergy**	**Evergy Kansas Central**	**Evergy Metro**	**Evergy**	**Evergy Kansas Central**	**Evergy Metro**
Discount rate	5.80 %	5.78 %	5.82 %	5.72 %	5.67 %	5.76 %
Rate of compensation increase	3.71 %	3.77 %	3.70 %	3.75 %	n/a	3.75 %
Interest crediting rate for cash balance plans	4.56 %	4.40 %	4.65 %	n/a	n/a	n/a

	Pension Benefits			Post-Retirement Benefits		
Weighted-average assumptions used to determine the benefit obligation at December 31, 2024	**Evergy**	**Evergy Kansas Central**	**Evergy Metro**	**Evergy**	**Evergy Kansas Central**	**Evergy Metro**
Discount rate	5.77 %	5.76 %	5.79 %	5.79 %	5.79 %	5.78 %
Rate of compensation increase	3.72 %	3.77 %	3.70 %	3.75 %	n/a	3.75 %
Interest crediting rate for cash balance plans	4.40 %	4.20 %	4.63 %	n/a	n/a	n/a

Weighted-average assumptions used to determine net costs for the year ended December 31, 2025	Pension Benefits			Post-Retirement Benefits		
	Evergy	Evergy Kansas Central	Evergy Metro	Evergy	Evergy Kansas Central	Evergy Metro
Discount rate	5.77 %	5.76 %	5.79 %	5.79 %	5.79 %	5.78 %
Expected long-term return on plan assets	6.84 %	6.90 %	6.78 %	5.48 %	5.75 %	5.22 %
Rate of compensation increase	3.72 %	3.77 %	3.71 %	3.75 %	n/a	3.75 %
Interest crediting rate for cash balance plans	4.40 %	4.20 %	4.63 %	n/a	n/a	n/a

Weighted-average assumptions used to determine net costs for the year ended December 31, 2024	Pension Benefits			Post-Retirement Benefits		
	Evergy	Evergy Kansas Central	Evergy Metro	Evergy	Evergy Kansas Central	Evergy Metro
Discount rate	5.35 %	5.34 %	5.35 %	5.43 %	5.45 %	5.41 %
Expected long-term return on plan assets	6.84 %	6.90 %	6.79 %	5.48 %	5.75 %	5.22 %
Rate of compensation increase	3.72 %	3.77 %	3.71 %	3.75 %	n/a	3.75 %
Interest crediting rate for cash balance plans	4.13 %	4.20 %	4.47 %	n/a	n/a	n/a

Evergy expects to contribute $110.7 million to the pension plans in 2026 to meet Employee Retirement Income Security Act of 1974, as amended (ERISA) funding requirements and regulatory orders, of which $76.4 million is expected to be paid by Evergy Kansas Central and $34.3 million is expected to be paid by Evergy Metro. The Evergy Companies' funding policy is to contribute amounts sufficient to meet the ERISA funding requirements and MPSC and KCC rate orders plus additional amounts as considered appropriate; therefore, actual contributions may differ from expected contributions. Also in 2026, Evergy expects to contribute $0.6 million to the post-retirement benefit plans, of which $0.3 million is expected to be paid by Evergy Kansas Central and $0.3 million is expected to be paid by Evergy Metro.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid through 2035.

	Pension Benefits			Post-Retirement Benefits		
	Evergy	Evergy Kansas Central	Evergy Metro	Evergy	Evergy Kansas Central	Evergy Metro
			(millions)			
2026	$ 139.2	$ 72.9	$ 64.7	$ 14.7	$ 8.3	$ 6.4
2027	142.3	73.2	67.5	14.3	8.1	6.2
2028	143.4	72.7	69.1	13.8	7.8	6.0
2029	144.1	72.5	70.0	11.8	6.4	5.4
2030	145.8	72.1	72.2	10.9	5.9	5.0
2031-2035	738.0	351.7	379.3	50.5	26.6	23.9

As of December 31, 2025, Evergy Kansas Central and Evergy Metro maintained a master trust for their non-union and Evergy Kansas Central's union pension benefits and a separate trust for Evergy Metro's union pension benefits. Evergy Kansas Central and Evergy Metro maintained separate trusts for their post-retirement benefits as of December 31, 2025. These plans are managed in accordance with prudent investor guidelines contained in the ERISA requirements.

The primary objective of Evergy Kansas Central's and Evergy Metro's pension plans is to provide a source of retirement income for its participants and beneficiaries, and the primary financial objectives of the plans are to minimize funding deficiencies and maintain the plans' ability to pay all benefit and expense obligations when due.

The primary objective of Evergy Kansas Central's and Evergy Metro's post-retirement benefit plans is to preserve capital, maintain sufficient liquidity and earn a consistent rate of return.

The investment strategies of both the Evergy Kansas Central and Evergy Metro pension and post-retirement plans support the above objectives of the plans. The portfolios are invested, and periodically rebalanced, to achieve the targeted allocations detailed below. The following table provides the target asset allocations by asset class for the Evergy Kansas Central and Evergy Metro pension and other post-retirement plan assets.

	Pension Benefits		Post-Retirement Benefits	
	Evergy Kansas Central	Evergy Metro	Evergy Kansas Central	Evergy Metro
Domestic equities	30%	28%	25%	21%
International equities	16%	18%	14%	9%
Bonds	39%	37%	61%	62%
Mortgage & asset backed securities	—%	—%	—%	7%
Real estate investments	4%	6%	—%	—%
Other investments	11%	11%	—%	1%

Fair Value Measurements

Evergy classifies recurring and non-recurring fair value measurements based on the fair value hierarchy as discussed in Note 14. The following are descriptions of the valuation methods of the primary fair value measurements disclosed below.

Domestic equities - consist of individually held domestic equity securities and domestic equity mutual funds. Securities and funds, which are publicly quoted, are valued based on quoted prices in active markets and are categorized as Level 1. Funds that are valued by fund administrators using the net asset value (NAV) per fund share, derived from the quoted prices in active markets of the underlying securities are not classified within the fair value hierarchy.

International equities - consist of individually held international equity securities and international equity mutual funds. Securities and funds, which are publicly quoted, are valued based on quoted prices in active markets and are categorized as Level 1.

Bond funds - consist of funds maintained by investment companies that invest in various types of fixed income securities consistent with the funds' stated objectives. Securities and funds, which are publicly quoted, are valued based on quoted prices in active markets and are categorized as Level 1.

Corporate bonds - consists of individually held, primarily domestic, corporate bonds that are traded in less than active markets or priced with models using highly observable inputs that are categorized as Level 2.

U.S. Treasury and agency bonds - consists of individually held U.S. Treasury securities and U.S. agency bonds. U.S. Treasury securities, which are publicly quoted, are valued based on quoted prices in active markets and are categorized as a Level 1. U.S. agency bonds, which are publicly quoted, are traded in less than active markets or priced with models using highly observable inputs and are categorized as Level 2.

Mortgage and asset backed securities - consists of individually held securities that are traded in less than active markets or valued with models using highly observable inputs that are categorized as Level 2.

Real estate investments - consists of institutional trust funds valued at NAV per fund share and are not categorized in the fair value hierarchy.

Combination debt/equity/other fund - consists of a fund that invests in various types of debt, equity and other asset classes consistent with the fund's stated objectives. The fund, which is publicly quoted, is valued based on quoted prices in active markets and is categorized as Level 1.

Alternative investments - consists of investments in institutional trust and hedge funds that are valued by fund administrators using the NAV per fund share, derived from the underlying investments of the fund, and are not classified within the fair value hierarchy.

Short-term investments - consists of fund investments in high-quality, short-term, U.S. dollar-denominated instruments with an average maturity of 60 days that are valued at NAV per fund share and are not categorized in the fair value hierarchy.

Cash and cash equivalents - consists of investments with original maturities of three months or less when purchased that are traded in active markets and are categorized as Level 1.

The fair values of the Evergy Companies' pension plan assets as of December 31, 2025 and 2024, by asset category are in the following tables.

		Fair Value Measurements Using			
Description	**December 31 2025**	**Level 1**	**Level 2**	**Level 3**	**Assets measured at NAV**
Evergy Kansas Central Pension Plans			(millions)		
Domestic equities	$ 175.0	$ 157.4	$ —	$ —	$ 17.6
International equities	102.1	102.1	—	—	—
Bond funds	249.9	249.9	—	—	—
Real estate investments	23.1	—	—	—	23.1
Combination debt/equity/other fund	31.7	31.7	—	—	—
Alternative investment funds	90.8	—	—	—	90.8
Short-term investments	11.9	—	—	—	11.9
Total	$ 684.5	$ 541.1	$ —	$ —	$ 143.4
Evergy Metro Pension Plans					
Domestic equities	$ 184.1	$ 170.9	$ —	$ —	$ 13.2
International equities	133.4	133.4	—	—	—
Bond funds	221.5	221.5	—	—	—
Corporate bonds	13.6	—	13.6	—	—
U.S. Treasury and agency bonds	10.5	9.7	0.8	—	—
Mortgage and asset backed securities	0.6	—	0.6	—	—
Real estate investments	42.7	—	—	—	42.7
Combination debt/equity/other fund	34.4	34.4	—	—	—
Alternative investment funds	83.6	—	—	—	83.6
Cash and cash equivalents	6.2	6.2	—	—	—
Short-term investments	8.9	—	—	—	8.9
Other	3.1	—	3.1	—	—
Total	$ 742.6	$ 576.1	$ 18.1	$ —	$ 148.4

Description	December 31 2024	Fair Value Measurements Using Level 1	Level 2	Level 3	Assets measured at NAV
Evergy Kansas Central Pension Plans			(millions)		
Domestic equities	$ 146.4	$ 128.5	$ —	$ —	$ 17.9
International equities	114.6	114.6	—	—	—
Bond funds	224.7	224.7	—	—	—
Real estate investments	22.3	—	—	—	22.3
Combination debt/equity/other fund	32.5	32.5	—	—	—
Alternative investment funds	88.3	—	—	—	88.3
Short-term investments	5.1	—	—	—	5.1
Total	$ 633.9	$ 500.3	$ —	$ —	$ 133.6
Evergy Metro Pension Plans					
Domestic equities	$ 150.4	$ 137.2	$ —	$ —	$ 13.2
International equities	128.7	128.7	—	—	—
Bond funds	181.7	181.7	—	—	—
Corporate bonds	19.3	—	19.3	—	—
U.S. Treasury and agency bonds	13.1	7.1	6.0	—	—
Mortgage and asset backed securities	4.4	—	4.4	—	—
Real estate investments	42.9	—	—	—	42.9
Combination debt/equity/other fund	33.2	33.2	—	—	—
Alternative investment funds	79.1	—	—	—	79.1
Cash and cash equivalents	6.1	6.1	—	—	—
Short-term investments	3.8	—	—	—	3.8
Other	2.8	—	2.8	—	—
Total	$ 665.5	$ 494.0	$ 32.5	$ —	$ 139.0

The fair values of the Evergy Companies' post-retirement plan assets as of December 31, 2025 and 2024, by asset category are in the following tables.

Description	December 31 2025	Fair Value Measurements Using			
		Level 1	Level 2	Level 3	Assets measured at NAV
Evergy Kansas Central Post-Retirement Benefit Plans			(millions)		
Domestic equities	$ 20.6	$ 20.6	$ —	$ —	$ —
International equities	11.8	11.8	—	—	—
Bond funds	44.9	44.9	—	—	—
Combination debt/equity/other fund	3.9	3.9	—	—	—
Short-term investments	1.2	—	—	—	1.2
Total	$ 82.4	$ 81.2	$ —	$ —	$ 1.2
Evergy Metro Post-Retirement Benefit Plans					
Domestic equities	$ 19.4	$ 19.4	$ —	$ —	$ —
International equities	9.0	9.0	—	—	—
Bond funds	30.2	30.2	—	—	—
Corporate bonds	11.8	—	11.8	—	—
U.S. Treasury and agency bonds	15.0	7.9	7.1	—	—
Mortgage and asset backed securities	0.2	—	0.2	—	—
Combination debt/equity/other fund	2.6	2.6	—	—	—
Cash and cash equivalents	1.1	1.1	—	—	—
Short-term investments	0.8	—	—	—	0.8
Other	0.3	—	0.3	—	—
Total	$ 90.4	$ 70.2	$ 19.4	$ —	$ 0.8

Description	December 31 2024	Fair Value Measurements Using: Level 1	Level 2	Level 3	Assets measured at NAV
Evergy Kansas Central Post-Retirement Benefit Plans			(millions)		
Domestic equities	$ 26.1	$ 26.1	$ —	$ —	$ —
International equities	17.3	17.3	—	—	—
Bond funds	49.9	49.9	—	—	—
Combination debt/equity/other fund	4.8	4.8	—	—	—
Short-term investments	1.0	—	—	—	1.0
Total	$ 99.1	$ 98.1	$ —	$ —	$ 1.0
Evergy Metro Post-Retirement Benefit Plans					
Domestic equities	$ 20.5	$ 20.5	$ —	$ —	$ —
International equities	11.3	11.3	—	—	—
Bond funds	37.6	37.6	—	—	—
Corporate bonds	14.5	—	14.5	—	—
U.S. Treasury and agency bonds	14.0	6.7	7.3	—	—
Mortgage and asset backed securities	0.6	—	0.6	—	—
Combination debt/equity/other fund	3.3	3.3	—	—	—
Cash and cash equivalents	1.7	1.7	—	—	—
Short-term investments	0.2	—	—	—	0.2
Other	0.2	—	0.2	—	—
Total	$ 103.9	$ 81.1	$ 22.6	$ —	$ 0.2

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The cost trend assumptions are detailed in the following tables.

Assumed annual health care cost growth rates as of December 31, 2025	Evergy	Evergy Kansas Central	Evergy Metro
Health care cost trend rate assumed for next year	7.0 %	n/a	7.0 %
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.5 %	n/a	4.5 %
Year that rate reaches ultimate trend	2033	n/a	2033

Assumed annual health care cost growth rates as of December 31, 2024	Evergy	Evergy Kansas Central	Evergy Metro
Health care cost trend rate assumed for next year	7.0 %	n/a	7.0 %
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.5 %	n/a	4.5 %
Year that rate reaches ultimate trend	2032	n/a	2032

Employee Savings Plans
Evergy has defined contribution savings plans (401(k)) that cover substantially all employees. Evergy matches employee contributions, subject to limits. The annual costs of the plans are detailed in the following table.

	2025	2024	2023
		(millions)	
Evergy	$ 29.6	$ 25.8	$ 24.1
Evergy Kansas Central	14.5	12.2	11.3
Evergy Metro	15.1	13.6	12.8

10. EQUITY COMPENSATION

Evergy's Long-Term Incentive Plan is an equity compensation plan approved by Evergy shareholders. The Long-Term Incentive Plan permits the grant of restricted stock, restricted stock units, bonus shares, stock options, stock appreciation rights, limited stock appreciation rights, director shares, director deferred share units and performance shares to directors, officers and other employees of Evergy. Common stock shares delivered by Evergy under the Long-Term Incentive Plan may be authorized but unissued, held in the treasury or purchased on the open market (including private purchases) in accordance with applicable securities laws. Evergy has a policy of delivering newly issued shares and does not expect to repurchase common shares during 2026 to satisfy equity compensation payments and director deferred share unit conversion. Evergy recognizes forfeitures as they occur.

The following table summarizes the Evergy Companies' equity compensation expense and the associated income tax benefit.

	2025	2024	2023
Evergy		(millions)	
Equity compensation expense	$ 20.7	$ 15.2	$ 17.7
Income tax benefit	1.9	1.9	1.6
Evergy Kansas Central			
Equity compensation expense	8.8	6.7	6.5
Income tax benefit	1.8	1.5	1.4
Evergy Metro			
Equity compensation expense	6.0	4.5	5.7
Income tax expense	(0.5)	—	(0.6)

Restricted Share Units
Evergy utilizes RSUs for new grants of stock-based compensation awards. RSU awards are grants that entitle the holder to receive shares of common stock as the awards vest. These RSU awards are defined as nonvested shares and do not include restrictions once the awards have vested. These RSUs either take the form of RSUs with performance measures that vest upon the achievement of specific performance goals or RSUs with only service requirements that vest solely upon the passage of time.

RSUs with Performance Measures
The payment of RSUs with performance measures is contingent upon achievement of specific performance goals over a stated period of time as approved by the Compensation and Leadership Development Committee of Evergy's Board. The numbers of RSUs with performances measures ultimately paid can vary from the numbers of RSUs with performance measures initially granted depending on Evergy's performance over the stated performance periods. Compensation expense for RSUs with performance measures is calculated by recognizing the portion of the fair value for each reporting period for which the requisite service has been rendered. Dividends are accrued over the vesting period and paid in cash based on the number of RSUs with performance measures ultimately paid.

The fair value of RSUs with performance measures is estimated using the market value of Evergy's stock at the valuation date and a Monte Carlo simulation technique that incorporates assumptions for inputs of expected

volatilities, dividend yield and risk-free rates. Expected volatility is based on daily stock price change during a historical period commensurate with the remaining term of the performance period of the grant. The risk-free rate is based upon the rate at the time of the evaluation for zero-coupon government bonds with a maturity consistent with the remaining performance period of the grant. The dividend yield is based on the most recent dividends paid and the actual closing stock price on the valuation date. For shares granted in 2025, inputs for expected volatility, dividend yield and the risk-free rate were 21%, 3.89% and 3.94% respectively.

RSU activity for awards with performance measures for 2025 is summarized in the following table.

	Nonvested Restricted Share Units	Grant Date Fair Value*
Beginning balance as of January 1, 2025	630,687	$ 55.45
Granted	198,441	76.68
Vested	(33,751)	60.72
Adjusted	(151,572)	57.34
Forfeited	(15,984)	61.70
Ending balance as of December 31, 2025	627,821	61.45

* weighted-average

As of December 31, 2025, the remaining weighted-average contractual term related to RSU awards with performance measures was 1.2 years. The weighted-average grant-date fair value of RSUs granted with performance measures was $76.68, $49.94 and $59.77 in 2025, 2024 and 2023, respectively. As of December 31, 2025, there was $15.5 million of unrecognized compensation expense related to unvested RSUs with performance measures. The total fair value of RSUs with performance measures that vested was $2.0 million, $10.2 million and $7.9 million in 2025, 2024, and 2023, respectively.

RSUs with Only Service Requirements

Evergy measures the fair value of RSUs with only service requirements based on the fair market value of the underlying common stock as of the grant date. RSU awards with only service conditions recognize compensation expense by multiplying shares by the grant-date fair value related to the RSU and recognizing it on a straight-line basis over the requisite service period for the entire award. Dividends are accrued over the vesting period and are invested in additional RSU's subject to the same service conditions.

RSU activity for awards with only service requirements for 2025 is summarized in the following table.

	Nonvested Restricted Share Units	Grant Date Fair Value*
Beginning balance as of January 1, 2025	306,655	$ 54.65
Granted	155,476	69.89
Vested	(90,856)	59.80
Forfeited	(11,259)	58.52
Ending balance as of December 31, 2025	360,016	60.06

* weighted-average

As of December 31, 2025, the remaining weighted-average contractual term related to RSU awards with only service requirements was 1.4 years. The weighted-average grant-date fair value of RSUs granted with only service requirements was $69.89, $51.22 and $57.47 in 2025, 2024 and 2023, respectively. As of December 31, 2025, there was $10.7 million of unrecognized compensation expense related to unvested RSUs. The total fair value of RSUs with only service requirements that vested was $5.4 million, $6.8 million and $3.3 million in 2025, 2024 and 2023, respectively.

11. SHORT-TERM BORROWINGS AND SHORT-TERM BANK LINES OF CREDIT

The Evergy Companies' $2.5 billion master credit facility expires in 2028. Evergy, Evergy Kansas Central, Evergy Metro and Evergy Missouri West have borrowing capacity under the master credit facility with specific sublimits for each borrower. These sublimits can be unilaterally adjusted by Evergy for each borrower provided the sublimits remain within minimum and maximum sublimits as specified in the facility. The applicable interest rates and commitment fees of the facility are also subject to changes in ratings by the credit rating agencies.

A default by any borrower under the facility or one of its significant subsidiaries on other indebtedness totaling more than $100.0 million constitutes a default by that borrower under the facility. Under the terms of this facility, each of Evergy, Evergy Kansas Central, Evergy Metro and Evergy Missouri West is required to maintain a total indebtedness to total capitalization ratio, as defined in the facility, of not greater than 0.65 to 1.00. As of December 31, 2025, Evergy, Evergy Kansas Central, Evergy Metro and Evergy Missouri West were in compliance with this covenant.

The following table summarizes the committed credit facilities (excluding receivable sale facilities discussed in Note 3) available to the Evergy Companies as of December 31, 2025 and 2024.

		Amounts Drawn				
	Master Credit Facility	Commercial Paper	Letters of Credit	Cash Borrowings	Available Borrowings Capacity	Weighted Average Interest Rate on Short-Term Borrowings
December 31, 2025			(millions)			
Evergy, Inc.	$ 700.0	$ 500.2	$ 0.7	$ —	$ 199.1	3.91%
Evergy Kansas Central	800.0	321.9	2.0	—	476.1	3.96%
Evergy Metro	500.0	245.3	1.1	—	253.6	3.85%
Evergy Missouri West	500.0	326.6	—	—	173.4	4.06%
Evergy	$ 2,500.0	$ 1,394.0	$ 3.8	$ —	$ 1,102.2	
December 31, 2024						
Evergy, Inc.	$ 300.0	$ 75.4	$ 0.7	$ —	$ 223.9	4.70%
Evergy Kansas Central	1,100.0	797.3	1.0	—	301.7	4.74%
Evergy Metro	600.0	158.7	1.0	—	440.3	4.64%
Evergy Missouri West	500.0	176.2	—	—	323.8	4.71%
Evergy	$ 2,500.0	$ 1,207.6	$ 2.7	$ —	$ 1,289.7	

In January 2026, Evergy, Inc. entered into a $55.0 million unsecured Term Loan Credit Agreement with an expiration date in January 2027. In February 2026, Evergy, Inc. entered into a $500.0 million unsecured Term Loan Credit Agreement with an expiration date in February 2027. Evergy's borrowings under the $500.0 million unsecured Term Loan Credit Agreement were used for, among other things, the repayment in full of all borrowings under the $55.0 million Term Loan Credit Agreement, the partial repurchase of Evergy's convertible notes as further described in Note 12 and general corporate purposes.

12. LONG-TERM DEBT

The Evergy Companies' long-term debt is detailed in the following tables.

December 31, 2025	Issuing Entity	Year Due	Evergy	Evergy Kansas Central	Evergy Metro
Mortgage Bonds				(millions)	
2.55% Series	Evergy Kansas Central, Inc.	2026	350.0	350.0	—
3.10% Series	Evergy Kansas Central, Inc.	2027	300.0	300.0	—
5.90% Series	Evergy Kansas Central, Inc.	2033	300.0	300.0	—
5.25% Series	Evergy Kansas Central Inc.	2035	600.0	600.0	—
4.125% Series	Evergy Kansas Central, Inc.	2042	550.0	550.0	—
4.10% Series	Evergy Kansas Central, Inc.	2043	430.0	430.0	—
4.625% Series	Evergy Kansas Central, Inc.	2043	250.0	250.0	—
4.25% Series	Evergy Kansas Central, Inc.	2045	300.0	300.0	—
3.25% Series	Evergy Kansas Central, Inc.	2049	300.0	300.0	—
3.45% Series	Evergy Kansas Central, Inc.	2050	500.0	500.0	—
5.70% Series	Evergy Kansas Central, Inc.	2053	400.0	400.0	—
6.53% Series	Evergy Kansas South, Inc.	2037	175.0	175.0	—
6.64% Series	Evergy Kansas South, Inc.	2038	100.0	100.0	—
4.30% Series	Evergy Kansas South, Inc.	2044	250.0	250.0	—
2.25% Series	Evergy Metro, Inc.	2030	400.0	—	400.0
4.95% Series	Evergy Metro, Inc.	2033	300.0	—	300.0
5.40% Series	Evergy Metro, Inc.	2034	300.0	—	300.0
5.125% Series	Evergy Metro, Inc.	2035	400.0	—	400.0
4.125% Series	Evergy Metro, Inc.	2049	400.0	—	400.0
5.15% Series	Evergy Missouri West, Inc.	2027	300.0	—	—
3.75% Series	Evergy Missouri West, Inc.	2032	250.0	—	—
5.65% Series	Evergy Missouri West, Inc.	2034	300.0	—	—
5.25% Series	Evergy Missouri West, Inc.	2035	300.0	—	—
Pollution Control Bonds					
3.50% Series	Evergy Kansas Central, Inc.	2032	45.0	45.0	—
3.50% Series	Evergy Kansas Central, Inc.	2032	30.5	30.5	—
2.98% Series[a]	Evergy Kansas South, Inc.	2027	21.9	21.9	—
3.607% Series	Evergy Kansas South, Inc.	2031	50.0	50.0	—
2.98% Series[a]	Evergy Kansas South, Inc.	2032	14.5	14.5	—
2.98% Series[a]	Evergy Kansas South, Inc.	2032	10.0	10.0	—
3.037% Series 2007A and 2007B[a]	Evergy Metro, Inc.	2035	146.5	—	146.5
4.05% EIRR Bonds	Evergy Metro, Inc.	2038	23.4	—	23.4
4.30% EIRR Bonds	Evergy Metro, Inc.	2045	79.5	—	79.5
Notes and Senior Notes					
4.70% Series	Evergy Kansas Central, Inc.	2028	300.0	300.0	—
6.05% Series (5.78% rate)[b][c]	Evergy Metro, Inc.	2035	250.0	—	250.0
5.30% Series[b]	Evergy Metro, Inc.	2041	400.0	—	400.0
4.20% Series[b]	Evergy Metro, Inc.	2047	300.0	—	300.0
4.20% Series[b]	Evergy Metro, Inc.	2048	300.0	—	300.0
2.86% Series A[d]	Evergy Missouri West, Inc.	2031	350.0	—	—
3.01% Series B[d]	Evergy Missouri West, Inc.	2033	75.0	—	—
4.06% Series B[d]	Evergy Missouri West, Inc.	2033	60.0	—	—
3.21% Series C[d]	Evergy Missouri West, Inc.	2036	75.0	—	—
4.74% Series C[d]	Evergy Missouri West, Inc.	2043	150.0	—	—
2.90% Series (3.77% rate)[c]	Evergy, Inc.	2029	800.0	—	—
Convertible Notes					
4.50% Convertible Notes	Evergy, Inc.	2027	1,400.0	—	—
Securitized Bonds					
5.10% Securitized Bonds	Evergy Missouri West Storm Funding I, LLC	2026 - 2040	303.4	—	—
Junior Subordinated Notes					
6.65% Junior Subordinated Notes	Evergy, Inc.	2055	500.0	—	—
Fair value adjustment[c]			76.1	—	—
Current maturities[f]			(367.0)	(350.0)	—
Unamortized debt discount and debt issuance costs			(109.6)	(43.8)	(28.0)
Total excluding current maturities[g]			$ 13,039.2	$ 4,883.1	$ 3,271.4

December 31, 2024	Issuing Entity	Year Due	Evergy	Evergy Kansas Central	Evergy Metro
Mortgage Bonds				(millions)	
3.25% Series	Evergy Kansas Central, Inc.	2025	$ 250.0	$ 250.0	$ —
2.55% Series	Evergy Kansas Central, Inc.	2026	350.0	350.0	—
3.10% Series	Evergy Kansas Central, Inc.	2027	300.0	300.0	—
5.90% Series	Evergy Kansas Central, Inc.	2033	300.0	300.0	—
4.125% Series	Evergy Kansas Central, Inc.	2042	550.0	550.0	—
4.10% Series	Evergy Kansas Central, Inc.	2043	430.0	430.0	—
4.625% Series	Evergy Kansas Central, Inc.	2043	250.0	250.0	—
4.25% Series	Evergy Kansas Central, Inc.	2045	300.0	300.0	—
3.25% Series	Evergy Kansas Central, Inc.	2049	300.0	300.0	—
3.45% Series	Evergy Kansas Central, Inc.	2050	500.0	500.0	—
5.70% Series	Evergy Kansas Central, Inc.	2053	400.0	400.0	—
6.53% Series	Evergy Kansas South, Inc.	2037	175.0	175.0	—
6.64% Series	Evergy Kansas South, Inc.	2038	100.0	100.0	—
4.30% Series	Evergy Kansas South, Inc.	2044	250.0	250.0	—
2.25% Series	Evergy Metro, Inc.	2030	400.0	—	400.0
4.95% Series	Evergy Metro, Inc.	2033	300.0	—	300.0
5.40% Series	Evergy Metro, Inc.	2034	300.0	—	300.0
4.125% Series	Evergy Metro, Inc.	2049	400.0	—	400.0
5.15% Series	Evergy Missouri West, Inc.	2027	300.0	—	—
3.75% Series	Evergy Missouri West, Inc.	2032	250.0	—	—
5.65% Series	Evergy Missouri West, Inc.	2034	300.0	—	—
Pollution Control Bonds					
3.19% Series[a]	Evergy Kansas Central, Inc.	2032	45.0	45.0	—
3.19% Series[a]	Evergy Kansas Central, Inc.	2032	30.5	30.5	—
3.19% Series[a]	Evergy Kansas South, Inc.	2027	21.9	21.9	—
2.50% Series	Evergy Kansas South, Inc.	2031	50.0	50.0	—
3.19% Series[a]	Evergy Kansas South, Inc.	2032	14.5	14.5	—
3.19% Series[a]	Evergy Kansas South, Inc.	2032	10.0	10.0	—
3.45% Series 2007A and 2007B[a]	Evergy Metro, Inc.	2035	146.5	—	146.5
3.50% EIRR Bonds	Evergy Metro, Inc.	2038	23.4	—	23.4
4.30% EIRR Bonds	Evergy Metro, Inc.	2045	79.5	—	79.5
Senior Notes					
3.65% Series[b]	Evergy Metro, Inc.	2025	350.0	—	350.0
6.05% Series (5.78% rate)[b][c]	Evergy Metro, Inc.	2035	250.0	—	250.0
5.30% Series[b]	Evergy Metro, Inc.	2041	400.0	—	400.0
4.20% Series[b]	Evergy Metro, Inc.	2047	300.0	—	300.0
4.20% Series[b]	Evergy Metro, Inc.	2048	300.0	—	300.0
3.49% Series A[d]	Evergy Missouri West, Inc.	2025	36.0	—	—
4.06% Series B[d]	Evergy Missouri West, Inc.	2033	60.0	—	—
4.74% Series C[d]	Evergy Missouri West, Inc.	2043	150.0	—	—
2.86% Series A[d]	Evergy Missouri West, Inc.	2031	350.0	—	—
3.01% Series B[d]	Evergy Missouri West, Inc.	2033	75.0	—	—
3.21% Series C[d]	Evergy Missouri West, Inc.	2036	75.0	—	—
2.90% Series (3.77% rate)[c]	Evergy, Inc.	2029	800.0	—	—
Convertible Notes					
4.50% Convertible Notes	Evergy, Inc.	2027	1,400.0	—	—
Securitized Bonds					
5.10% Securitized Bonds	Evergy Missouri West Storm Funding I, LLC	2025 - 2040	319.6	—	—
Junior Subordinated Notes					
6.65% Junior Subordinated Notes	Evergy, Inc.	2055	500.0	—	—
Fair value adjustment[e]			81.7	—	—
Current maturities[f]			(651.7)	(250.0)	(350.0)
Unamortized debt discount and debt issuance costs			(112.7)	(43.4)	(26.0)
Total excluding current maturities[g]			$ 11,809.2	$ 4,333.5	$ 2,873.4

[a] Variable rate. The bondholders of these tax-exempt bonds are permitted to tender the tax-exempt bonds to the issuer for purchase and, if tendered, the issuer is obligated to purchase any such bonds that cannot be remarketed to other investors. These tax-exempt bonds are classified as long-term debt due to the issuer's intent and ability to utilize such borrowings as long-term financing.

[b] Effectively secured pursuant to the General Mortgage Indenture and Deed of Trust dated as of December 1, 1986, as amended and supplemented (Evergy Metro Mortgage Indenture) through the issuance of collateral mortgage bonds to the trustee in 2019.
[c] Rate after amortizing gains/losses recognized in OCI on settlements of interest rate hedging instruments.
[d] Unconditionally guaranteed by Evergy, Inc.
[e] Represents the fair value adjustments recorded at Evergy consolidated related to the long-term debt of Evergy Metro and Evergy Missouri West in connection with purchase accounting for the merger that created Evergy. This amount is not part of future principal payments and will amortize over the remaining life of the associated debt instruments.
[f] Evergy's current maturities total as of December 31, 2025, includes no fair value adjustments recorded in connection with purchase accounting for the merger that created Evergy. Evergy's current maturities total as of December 31, 2024, included $(0.5) million of fair value adjustments recorded in connection with purchase accounting for the merger.
[g] As of December 31, 2025 and 2024, does not include $50.0 million and $21.9 million of secured Series 2005 Environmental Improvement Revenue Refunding (EIRR) bonds because the bonds were repurchased in September 2015 and are held by Evergy Metro.

Mortgage Bonds

The Evergy Kansas Central, Evergy Kansas South, Evergy Metro and Evergy Missouri West mortgages each contain provisions restricting the amount of first mortgage bonds (FMBs) or mortgage bonds, as applicable, that can be issued by each entity. Evergy Kansas Central, Evergy Kansas South, Evergy Metro and Evergy Missouri West must comply with these restrictions prior to the issuance of additional FMBs, mortgage bonds or other secured indebtedness.

Under the Mortgage and Deed of Trust, dated July 1, 1939, as amended and supplemented (Evergy Kansas Central Mortgage Indenture), additional Evergy Kansas Central mortgage bonds may be issued on the basis of 70% of property additions or retired bonds. The amount of Evergy Kansas Central FMBs authorized by Evergy Kansas Central's Mortgage Indenture is subject to certain limitations as described below. The amount of Evergy Kansas South FMBs authorized by the Evergy Kansas South Mortgage and Deed of Trust, dated April 1, 1940, as amended and supplemented (Evergy Kansas South Mortgage Indenture), is limited to a maximum of $3.5 billion, unless amended further. FMBs are secured by utility assets. Amounts of additional FMBs that may be issued are subject to property, earnings and certain restrictive provisions, except in connection with certain refundings, of each mortgage. As of December 31, 2025, approximately $2.3 billion and $2.9 billion principal amounts of additional Evergy Kansas Central FMBs or Evergy Kansas South FMBs, respectively, could be issued under the most restrictive provisions of their mortgages.

Evergy Metro has issued mortgage bonds under the General Mortgage Indenture and Deed of Trust, dated as of December 1, 1986, as amended and supplemented (Evergy Metro Mortgage Indenture), which creates a mortgage lien on substantially all of Evergy Metro's utility plant. Additional Evergy Metro bonds may be issued on the basis of 75% of property additions or retired bonds. As of December 31, 2025, approximately $5.6 billion principal amount of additional Evergy Metro mortgage bonds could be issued under the most restrictive provisions in the mortgage.

Evergy Missouri West has issued mortgage bonds under the First Mortgage Indenture and Deed of Trust, dated as of March 1, 2022, as supplemented (Evergy Missouri West Mortgage Indenture), which creates a first mortgage lien on substantially all of Evergy Missouri West's present properties and certain after-acquired properties, subject to certain exceptions. Additional Evergy Missouri West mortgage bonds may be issued on the basis of 75% of property additions or retired bonds. As of December 31, 2025, approximately $2.1 billion principal amount of additional Evergy Missouri West mortgage bonds could be issued under the most restrictive provisions in the mortgage.

In March 2025, Evergy Kansas Central issued, at a discount, $300.0 million of 5.25% FMBs, maturing in 2035. Proceeds were used to repay a portion of commercial paper and for general corporate purposes.

In August 2025, Evergy Metro issued, at a discount, $400.0 million of 5.125% Mortgage Bonds, maturing in 2035. Proceeds were used to repay its 3.65% Senior Notes at maturity and for general corporate purposes.

In November 2025, Evergy Missouri West issued, at a discount, $300.0 million of 5.25% FMBs, maturing in 2035. Proceeds were used to repay a portion of commercial paper borrowings outstanding.

In December 2025, Evergy Kansas Central issued, at a premium, $300.0 million of 5.25% FMBs, maturing in 2035. Proceeds were primarily used to repay its $250.0 million of 3.25% FMBs at maturity and for general corporate purposes.

Notes and Senior Notes
Under the terms of the note purchase agreements for certain Evergy Missouri West senior notes, Evergy Missouri West is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the agreements, not greater than 0.65 to 1.00. In addition, Evergy Missouri West's priority debt, as defined in the agreements, cannot exceed 15% of consolidated tangible net worth, as defined in the agreements. As of December 31, 2025, Evergy Missouri West was in compliance with these covenants.

In March 2025, Evergy Kansas Central issued, at a discount, $300.0 million of 4.70% Notes, maturing in 2028. Proceeds were used to repay a portion of commercial paper and for general corporate purposes.

In August 2025, Evergy Metro repaid its $350.0 million of 3.65% Senior Notes at maturity.

In August 2025, Evergy Missouri West repaid its $36.0 million of 3.49% Senior Notes at maturity.

Convertible Notes
In December 2023, Evergy, Inc. issued $1.4 billion aggregate principal amount of 4.50% Convertible Notes (Convertible Notes). The Convertible Notes will mature in December 2027, unless earlier converted or repurchased, but are not redeemable at the option of Evergy, Inc. No sinking fund is provided for the Convertible Notes. The Convertible Notes are direct, senior unsecured obligations of Evergy, Inc. and rank equal in right of payment to any of Evergy, Inc.'s unsecured indebtedness that is not so subordinated, including Evergy, Inc.'s master revolving credit agreement that governs its senior unsecured revolving credit facility, its commercial paper obligations and its 2.90% Senior Notes due 2029. The Convertible Notes are not guaranteed by any of Evergy, Inc.'s subsidiaries.

Holders may convert their Convertible Notes at any time prior to the close of business on the business day immediately preceding September 15, 2027 only under the following circumstances:

a. During any calendar quarter commencing after the calendar quarter ending on March 31, 2024 (and only such calendar quarter), if the last reported sales price of Evergy, Inc. common stock for at least 20 trading days (whether or not consecutive) during a period of 30 consecutive trading days ending on, and including, the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day;

b. During the five business day period after any ten consecutive trading day period (Measurement Period) in which the trading price per $1,000 principal amount of Convertible Notes for each trading day of the Measurement Period was less than 98% of the product of the last reported sale price of Evergy, Inc. common stock and the conversion rate on each such trading day; or

c. Upon the occurrence of specific corporate events specified in the indenture governing the Convertible Notes.

On or after September 15, 2027 until the close of business on the business day immediately preceding the maturity date, a holder may convert their notes at any time, regardless of the foregoing circumstances.

Upon conversion, Evergy, Inc. will pay cash up to the aggregate principal amount of the Convertible Notes to be converted and pay or deliver, as the case may be, cash, shares of Evergy, Inc. common stock or a combination of cash and shares of Evergy, Inc. common stock, at Evergy, Inc.’s election, in respect of the remainder, if any, of its conversion obligation in excess of the aggregate principal amount of the Convertible Notes being converted, as described in the indenture governing the Convertible Notes. The Convertible Notes were initially convertible at a rate of 16.1809 shares of Evergy, Inc. common stock per $1,000 principal amount of Convertible Notes, which was equivalent to an initial conversion price of approximately $61.80 per share of Evergy, Inc. common stock. The conversion rate is subject to adjustment in some events but will not be adjusted for any accrued and unpaid interest.

In addition, following certain corporate events that occur prior to the maturity date, Evergy, Inc. will, in certain circumstances, increase the conversion rate for a holder who elects to convert their Convertible Notes in connection with such a corporate event. If Evergy, Inc. undergoes a fundamental change, a holder may require Evergy, Inc. to repurchase for cash all or any portion of their Convertible Notes at a fundamental change repurchase price equal to 100% of the principal amount of the Convertible Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the fundamental change repurchase date.

In January and February 2026, Evergy, Inc. repurchased $244.1 million aggregate principal amount of the Convertible Notes, under separate, privately negotiated repurchase agreements with certain holders of its Convertible Notes, for a total repurchase cost (excluding accrued and unpaid interest) of approximately $308.6 million. The repurchases were funded by Term Loan Credit Agreements executed in January and February 2026, see Note 11 for additional information on the Term Loan Credit Agreements. After these January and February 2026 repurchases, $1,155.9 million aggregate principal amount of Convertible Notes remain outstanding.

Pollution Control Bonds

In July 2025, Evergy Metro remarketed its unsecured Series 2008 EIRR bonds maturing in 2038 totaling $23.4 million at a fixed rate of 4.05% through June 2030.

In November 2025, Evergy Kansas Central redeemed and reissued its variable rate Series 1994 pollution control bonds maturing in 2032 totaling $45.0 million and $30.5 million at a fixed rate of 3.50% through April 2032.

Scheduled Maturities

Evergy's, Evergy Kansas Central's and Evergy Metro's long-term debt maturities for the next five years are detailed in the following table.

	2026	2027	2028	2029	2030
			(millions)		
Evergy[a]	$ 367.0	$ 2,039.8	$ 318.8	$ 819.8	$ 420.8
Evergy Kansas Central	350.0	321.9	300.0	—	—
Evergy Metro	—	—	—	—	400.0

[a] The Evergy maturities for 2027 are inclusive of the $244.1 million of Convertible Notes that were repurchased in January and February 2026, based on agreements that were executed in January 2026. This principal amount is reflected as a long-term liability on the consolidated balance sheet as of December 31, 2025.

13. DERIVATIVE INSTRUMENTS

Commodity Price Risk

The Evergy Companies engage in the wholesale and retail sale of electricity as part of their regulated electric operations. These activities expose the Evergy Companies to market risks associated with the price of electricity, natural gas and other energy-related products. Management has established risk management policies and strategies to reduce the potentially adverse effects that the volatility of the markets may have on the Evergy Companies' operating results. The Evergy Companies' commodity risk management activities, which are subject to the management, direction and control of an internal risk management committee, utilize derivative instruments to reduce the effects of fluctuations in wholesale sales and fuel and purchased power expense caused by commodity price volatility.

Interest Rate Risk

The Evergy Companies are also exposed to market risks arising from changes in interest rates and may use derivative instruments to manage these risks. The Evergy Companies' interest rate risk management activities have included using derivative instruments to hedge against future interest rate fluctuations on anticipated debt issuances. From time to time, this may include entering into interest rate swap agreements to mitigate exposure to interest rate fluctuations associated with forecasted debt transactions.

Trading
The Evergy Companies also engage in non-regulated energy marketing activity for trading purposes, primarily at Evergy Kansas Central, which focuses on seizing market opportunities to create value driven by expected changes in the market prices of commodities, primarily electricity and natural gas.

Accounting for Derivative Instruments
The Evergy Companies consider various qualitative factors, such as contract and marketplace attributes, in designating derivative instruments at inception. The Evergy Companies may elect the normal purchases and normal sales (NPNS) exception, which requires the effects of the derivative to be recorded when the underlying contract settles under accrual accounting. The Evergy Companies account for derivative instruments that are not designated as NPNS as (i) economic hedges or trading contracts (non-hedging derivatives) or (ii) cash flow hedges, which are recorded as assets or liabilities on the consolidated balance sheets at fair value. See Note 14 for additional information on the Evergy Companies' methods for assessing the fair value of derivative instruments.

Changes in the fair value of derivative instruments designated as economic hedges (non-hedging derivatives) that are related to the Evergy Companies' regulated operations are deferred to a regulatory asset or regulatory liability when determined to be probable of future recovery or refund from/to customers. Recovery of the actual costs incurred by regulated activities will not impact earnings but will impact cash flows due to the timing of the recovery mechanism.

Changes in the fair value of derivative instruments designated as trading contracts (non-hedging derivatives) are recorded in operating revenues on the Evergy Companies' statements of income and comprehensive income.

Changes in the fair value of interest rate swaps designated as cash flow hedges are initially recorded in OCI. These amounts are subsequently reclassified into earnings as an adjustment to interest expense over the same period that the hedged interest payments affect earnings. The Evergy Companies classify cash flows from derivative instruments accounted for as a cash flow hedge in the same category as the cash flows from the items being hedged.

The Evergy Companies offset fair value amounts recognized for derivative instruments under master netting arrangements, which include rights to reclaim cash collateral (a receivable), or the obligation to return cash collateral (a payable).

The gross notional contract amount by commodity type for non-hedging derivative instruments is summarized in the following table.

		December 31	
Non-hedging derivatives	**Notional volume unit of measure**	**2025**	**2024**
		(millions)	
Evergy			
Commodity contracts			
Power	MWhs	63.0	51.3
Natural gas	MMBtu	54.6	598.7
Evergy Kansas Central			
Commodity contracts			
Power	MWhs	41.0	31.3
Natural gas	MMBtu	54.6	598.7
Evergy Metro			
Commodity contracts			
Power	MWhs	16.5	15.3

The fair values of Evergy's open non-hedging derivative positions and balance sheet classifications are summarized in the following tables. The fair values below are gross values before netting agreements and netting of cash collateral.

Evergy		December 31 2025	2024
Non-hedging derivatives	**Balance sheet location**		
		(millions)	
Commodity contracts			
Power	Other assets - current	$ 40.8	$ 24.6
	Other assets - long-term	35.1	43.8
Natural gas	Other assets - current	6.4	16.9
	Other assets - long-term	—	2.1
Total derivative assets		$ 82.3	$ 87.4
Commodity contracts			
Power	Other liabilities - current	$ 30.8	$ 14.2
	Other liabilities - long-term	37.0	41.5
Natural gas	Other liabilities - current	6.7	17.9
	Other liabilities - long-term	0.1	2.1
Total derivative liabilities		$ 74.6	$ 75.7

Evergy Kansas Central		December 31 2025	2024
Non-hedging derivatives	**Balance sheet location**		
		(millions)	
Commodity contracts			
Power	Other assets - current	$ 33.4	$ 11.3
	Other assets - long-term	35.1	43.8
Natural gas	Other assets - current	6.4	16.9
	Other assets - long-term	—	2.1
Total derivative assets		$ 74.9	$ 74.1
Commodity contracts			
Power	Other liabilities - current	$ 27.9	$ 11.5
	Other liabilities - long-term	37.0	41.5
Natural gas	Other liabilities - current	6.7	17.9
	Other liabilities - long-term	0.1	2.1
Total derivative liabilities		$ 71.7	$ 73.0

Evergy Metro		December 31 2025	2024
Non-hedging derivatives	**Balance sheet location**		
		(millions)	
Commodity contracts			
Power	Other assets - current	$ 6.6	$ 10.1
Total derivative assets		$ 6.6	$ 10.1
Commodity contracts			
Power	Other liabilities - current	$ 2.3	$ 2.0
Total derivative liabilities		$ 2.3	$ 2.0

The following tables present the line items on the Evergy Companies' consolidated balance sheets where non-hedging derivative assets and liabilities are reported. The gross amounts offset in the tables below show the effect of master netting arrangements and include collateral posted to offset the net position.

December 31, 2025	Evergy	Evergy Kansas Central	Evergy Metro
Non-hedging derivatives		(millions)	
Derivative Assets			
Current			
Gross amounts recognized	$ 47.2	$ 39.8	$ 6.6
Gross amounts offset	(29.9)	(27.0)	(2.3)
Net amounts presented in other assets - current	$ 17.3	$ 12.8	$ 4.3
Long-Term			
Gross amounts recognized	$ 35.1	$ 35.1	$ —
Gross amounts offset	(8.0)	(8.0)	—
Net amounts presented in other assets - long-term	$ 27.1	$ 27.1	$ —
Derivative Liabilities			
Current			
Gross amounts recognized	$ 37.5	$ 34.6	$ 2.3
Gross amounts offset	(29.3)	(26.4)	(2.3)
Net amounts presented in other liabilities - current	$ 8.2	$ 8.2	$ —
Long-Term			
Gross amounts recognized	$ 37.1	$ 37.1	$ —
Gross amounts offset	(7.5)	(7.5)	—
Net amounts presented in other liabilities - long-term	$ 29.6	$ 29.6	$ —

December 31, 2024	Evergy	Evergy Kansas Central	Evergy Metro
Non-hedging derivatives		(millions)	
Derivative Assets			
Current			
Gross amounts recognized	$ 41.5	$ 28.2	$ 10.1
Gross amounts offset	(28.4)	(25.7)	(2.0)
Net amounts presented in other assets - current	$ 13.1	$ 2.5	$ 8.1
Long-Term			
Gross amounts recognized	$ 45.9	$ 45.9	$ —
Gross amounts offset	(12.0)	(12.0)	—
Net amounts presented in other assets - long-term	$ 33.9	$ 33.9	$ —
Derivative Liabilities			
Current			
Gross amounts recognized	$ 32.1	$ 29.4	$ 2.0
Gross amounts offset	(26.1)	(23.4)	(2.0)
Net amounts presented in other liabilities - current	$ 6.0	$ 6.0	$ —
Long-Term			
Gross amounts recognized	$ 43.6	$ 43.6	$ —
Gross amounts offset	(3.8)	(3.8)	—
Net amounts presented in other liabilities - long-term	$ 39.8	$ 39.8	$ —

The following table summarizes the amounts of gain (loss) recognized in income for the change in fair value of derivatives not designated as hedging instruments for the Evergy Companies.

Non-hedging derivatives - Location of gain (loss)	Contract type	2025	2024	2023
Evergy			(millions)	
Operating revenues	Commodity	$ 41.8	$ 23.6	$ 22.9
Total		$ 41.8	$ 23.6	$ 22.9
Evergy Kansas Central				
Operating revenues	Commodity	$ 41.8	$ 23.6	$ 22.9
Total		$ 41.8	$ 23.6	$ 22.9

The following table summarizes the gross notional contract amount by type for hedging derivative instruments.

		December 31	
Hedging derivatives - Cash flow hedge	**Notional volume unit of measure**	**2025**	**2024**
Evergy		(millions)	
Interest rate swaps	USD	$ 100.0	$ —

The fair value of Evergy's open hedging derivative positions and balance sheet classifications are summarized in the following table. The fair values represent both the gross and net impact of netting agreements and the netting of cash collateral.

		December 31	
Hedging derivatives - Cash flow hedge	**Balance sheet location**	**2025**	**2024**
Interest rate swaps		(millions)	
	Other assets - long-term	$ 0.6	$ —
Total derivative assets		$ 0.6	$ —

Credit risk of the Evergy Companies' derivative instruments relates to the potential adverse financial impact resulting from non-performance by a counterparty of its contractual obligations. The Evergy Companies maintain credit policies and employ credit risk mitigation, such as collateral requirements or letters of credit, when necessary to minimize their overall credit risk and monitor exposure. Substantially all of the Evergy Companies' counterparty credit risk associated with derivative instruments relates to Evergy Kansas Central's non-regulated energy marketing activities. As of December 31, 2025, if counterparty groups completely failed to perform on contracts, Evergy's and Evergy Kansas Central's maximum exposure related to derivative assets was $35.8 million. As of December 31, 2025, the potential loss after the consideration of applicable master netting arrangements and collateral received for Evergy and Evergy Kansas Central was $27.0 million.

Certain of the Evergy Companies' derivative instruments contain collateral provisions that are tied to the Evergy Companies' credit ratings and may require the posting of collateral for various reasons, including if the Evergy Companies' credit ratings were to fall below investment grade. Substantially all of these derivative instruments relate to Evergy Kansas Central's non-regulated energy marketing activities. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2025, was $35.6 million for which Evergy and Evergy Kansas Central have posted $5.1 million collateral in the normal course of business. If the credit-risk-related contingent features underlying these agreements were triggered as of December 31, 2025, Evergy and Evergy Kansas Central could be required to post an additional $28.8 million of collateral to their counterparties.

14. FAIR VALUE MEASUREMENTS

Values of Financial Instruments

GAAP establishes a hierarchical framework for disclosing the transparency of the inputs utilized in measuring assets and liabilities at fair value. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy levels. In addition, the Evergy Companies measure certain investments that do not have a readily determinable fair value at NAV, which are not included in the fair value hierarchy. Further explanation of these levels and NAV is summarized below.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed on public exchanges or exchange-traded derivative instruments.

Level 2 – Pricing inputs are not quoted prices in active markets but are either directly or indirectly observable. The types of assets and liabilities included in Level 2 are certain marketable debt securities, financial instruments traded in less than active markets, non-exchange traded derivative instruments with observable forward curves and options contracts.

Level 3 – Significant inputs to pricing have little or no transparency. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation. The types of assets and liabilities included in Level 3 are non-exchange traded derivative instruments for which observable market data is not available to corroborate the valuation inputs and transmission congestion rights (TCRs) in the SPP Integrated Marketplace.

NAV - Investments that do not have a readily determinable fair value are measured at NAV. These investments do not consider the observability of inputs and, therefore, they are not included within the fair value hierarchy. The Evergy Companies include in this category investments in private equity, real estate and alternative investment funds that do not have a readily determinable fair value. The underlying alternative investments include collateralized debt obligations, mezzanine debt and a variety of other investments.

The Evergy Companies record cash and cash equivalents, accounts receivable and short-term borrowings on their consolidated balance sheets at cost, which approximates fair value due to the short-term nature of these instruments.

Fair Value of Long-Term Debt

The Evergy Companies measure the fair value of long-term debt using Level 2 measurements available as of the measurement date. The book value and fair value of the Evergy Companies' long-term debt are summarized in the following table.

	December 31, 2025		December 31, 2024	
	Book Value	Fair Value	Book Value	Fair Value
Long-term debt[a]		(millions)		
Evergy[b]	$ 13,406.2	$ 13,018.9	$ 12,460.9	$ 11,535.0
Evergy Kansas Central	5,233.1	4,812.1	4,583.5	4,031.7
Evergy Metro	3,271.4	3,122.7	3,223.4	2,966.3

[a] Includes current maturities.

[b] Book value as of December 31, 2025 and 2024, includes $76.1 million and $81.7 million, respectively, of fair value adjustments recorded in connection with purchase accounting for the merger that created Evergy, which are not part of future principal payments and will amortize over the remaining life of the associated debt instrument.

Recurring Fair Value Measurements

The following tables include balances of financial assets and liabilities measured at fair value on a recurring basis.

Description	December 31, 2025	Netting	Level 1	Level 2	Level 3	NAV
Evergy Kansas Central			(millions)			
Assets						
Nuclear decommissioning trust[a]						
Domestic equity funds	$ 159.8	$ —	$ 151.5	$ —	$ —	$ 8.3
International equity funds	95.9	—	95.9	—	—	—
Core bond fund	71.5	—	71.5	—	—	—
High-yield bond fund	23.9	—	23.9	—	—	—
Emerging markets bond fund	23.9	—	23.9	—	—	—
Combination debt/equity/other fund	23.8	—	23.8	—	—	—
Alternative investments fund	49.6	—	—	—	—	49.6
Real estate securities fund	16.8	—	—	—	—	16.8
Cash equivalents	0.8	—	0.8	—	—	—
Total nuclear decommissioning trust	466.0	—	391.3	—	—	74.7
Rabbi trust						
Fixed income funds	13.7	—	13.7	—	—	—
Equity funds	7.8	—	7.8	—	—	—
Combination debt/equity/other fund	1.8	—	1.8	—	—	—
Cash equivalents	0.2	—	0.2	—	—	—
Total rabbi trust	23.5	—	23.5	—	—	—
Derivative instruments - commodity contracts[b]						
Power	38.7	(29.8)	30.1	36.3	2.1	—
Natural gas	1.2	(5.2)	6.4	—	—	—
Total derivative assets	39.9	(35.0)	36.5	36.3	2.1	—
Total assets	529.4	(35.0)	451.3	36.3	2.1	74.7
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	36.2	(28.7)	23.5	39.1	2.3	—
Natural gas	1.6	(5.2)	6.8	—	—	—
Total derivative liabilities	37.8	(33.9)	30.3	39.1	2.3	—
Total liabilities	$ 37.8	$ (33.9)	$ 30.3	$ 39.1	$ 2.3	$ —
Evergy Metro						
Assets						
Nuclear decommissioning trust[a]						
Equity securities	$ 436.8	$ —	$ 436.8	$ —	$ —	$ —
Debt securities						
U.S. Treasury	56.8	—	56.8	—	—	—
U.S. Agency	0.1	—	—	0.1	—	—
State and local obligations	2.1	—	—	2.1	—	—
Corporate bonds	51.5	—	—	51.5	—	—
Cash equivalents	3.5	—	3.5	—	—	—
Total nuclear decommissioning trust	550.8	—	497.1	53.7	—	—
Self-insured health plan trust[c]						
Equity securities	2.7	—	2.7	—	—	—
Debt securities	15.3	—	3.8	11.5	—	—
Cash and cash equivalents	2.5	—	2.5	—	—	—
Total self-insured health plan trust	20.5	—	9.0	11.5	—	—
Derivative instruments - commodity contracts[b]						
Power	4.3	(2.3)	—	—	6.6	—
Total derivative assets	4.3	(2.3)	—	—	6.6	—
Total assets	575.6	(2.3)	506.1	65.2	6.6	—
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	—	(2.3)	—	—	2.3	—
Total derivative liabilities	—	(2.3)	—	—	2.3	—
Total liabilities	$ —	$ (2.3)	$ —	$ —	$ 2.3	$ —

Description	December 31, 2025	Netting	Level 1	Level 2	Level 3	NAV
Other Evergy			(millions)			
Assets						
Rabbi trusts						
Core bond fund	$ 7.7	$ —	$ 7.7	$ —	$ —	$ —
Total rabbi trusts	7.7	—	7.7	—	—	—
Derivative instruments - commodity contracts[b]						
Power	0.2	(0.6)	—	—	0.8	—
Derivative instruments - interest rate swaps[b]	0.6	—	—	0.6	—	—
Total derivative assets	0.8	(0.6)	—	0.6	0.8	—
Total assets	8.5	(0.6)	7.7	0.6	0.8	—
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	—	(0.6)	—	—	0.6	—
Total derivative liabilities	—	(0.6)	—	—	0.6	—
Total liabilities	$ —	$ (0.6)	$ —	$ —	$ 0.6	$ —
Evergy						
Assets						
Nuclear decommissioning trust[a]	$ 1,016.8	$ —	$ 888.4	$ 53.7	$ —	$ 74.7
Rabbi trusts	31.2	—	31.2	—	—	—
Self-insured health plan trust[c]	20.5	—	9.0	11.5	—	—
Derivative instruments - commodity contracts[b]						
Power	43.2	(32.7)	30.1	36.3	9.5	—
Natural gas	1.2	(5.2)	6.4	—	—	—
Derivative instruments - interest rate swaps[b]	0.6	—	—	0.6	—	—
Total derivative assets	45.0	(37.9)	36.5	36.9	9.5	—
Total assets	1,113.5	(37.9)	965.1	102.1	9.5	74.7
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	36.2	(31.6)	23.5	39.1	5.2	—
Natural gas	1.6	(5.2)	6.8	—	—	—
Total derivative liabilities	37.8	(36.8)	30.3	39.1	5.2	—
Total liabilities	$ 37.8	$ (36.8)	$ 30.3	$ 39.1	$ 5.2	$ —

Description	December 31, 2024	Netting	Level 1	Level 2	Level 3	NAV
Evergy Kansas Central			(millions)			
Assets						
Nuclear decommissioning trust[a]						
Domestic equity funds	$ 142.9	$ —	$ 134.0	$ —	$ —	$ 8.9
International equity funds	81.6	—	81.6	—	—	—
Core bond fund	66.7	—	66.7	—	—	—
High-yield bond fund	33.7	—	33.7	—	—	—
Emerging markets bond fund	20.6	—	20.6	—	—	—
Alternative investments fund	45.6	—	—	—	—	45.6
Real estate securities fund	16.3	—	—	—	—	16.3
Cash equivalents	0.5	—	0.5	—	—	—
Total nuclear decommissioning trust	407.9	—	337.1	—	—	70.8
Rabbi trust						
Fixed income funds	14.6	—	14.6	—	—	—
Equity funds	6.9	—	6.9	—	—	—
Combination debt/equity/other fund	1.7	—	1.7	—	—	—
Cash equivalents	0.2	—	0.2	—	—	—
Total rabbi trust	23.4	—	23.4	—	—	—
Derivative instruments - commodity contracts[b]						
Power	35.1	(20.0)	11.7	40.5	2.9	—
Natural gas	1.3	(17.7)	18.9	0.1	—	—
Total derivative assets	36.4	(37.7)	30.6	40.6	2.9	—
Total assets	467.7	(37.7)	391.1	40.6	2.9	70.8
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	43.5	(9.5)	4.5	44.2	4.3	—
Natural gas	2.3	(17.7)	19.9	0.1	—	—
Total derivative liabilities	45.8	(27.2)	24.4	44.3	4.3	—
Total liabilities	$ 45.8	$ (27.2)	$ 24.4	$ 44.3	$ 4.3	$ —
Evergy Metro						
Assets						
Nuclear decommissioning trust[a]						
Equity securities	$ 368.8	$ —	$ 368.8	$ —	$ —	$ —
Debt securities						
U.S. Treasury	55.3	—	55.3	—	—	—
State and local obligations	2.1	—	—	2.1	—	—
Corporate bonds	42.7	—	—	42.7	—	—
Cash equivalents	3.0	—	3.0	—	—	—
Total nuclear decommissioning trust	471.9	—	427.1	44.8	—	—
Self-insured health plan trust[c]						
Equity securities	2.3	—	2.3	—	—	—
Debt securities	14.3	—	3.2	11.1	—	—
Cash and cash equivalents	2.3	—	2.3	—	—	—
Total self-insured health plan trust	18.9	—	7.8	11.1	—	—
Derivative instruments - commodity contracts[b]						
Power	8.1	(2.0)	—	—	10.1	—
Total derivative assets	8.1	(2.0)	—	—	10.1	—
Total assets	498.9	(2.0)	434.9	55.9	10.1	—
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	—	(2.0)	—	—	2.0	—
Total derivative liabilities	—	(2.0)	—	—	2.0	—
Total liabilities	$ —	$ (2.0)	$ —	$ —	$ 2.0	$ —

Description	December 31, 2024	Netting	Level 1	Level 2	Level 3	NAV
Other Evergy			(millions)			
Assets						
Rabbi trusts						
Core bond fund	$ 8.0	$ —	$ 8.0	$ —	$ —	$ —
Total rabbi trusts	8.0	—	8.0	—	—	—
Derivative instruments - commodity contracts[b]						
Power	2.5	(0.7)	—	—	3.2	—
Total derivative assets	2.5	(0.7)	—	—	3.2	—
Total assets	10.5	(0.7)	8.0	—	3.2	—
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	—	(0.7)	—	—	0.7	—
Total derivative liabilities	—	(0.7)	—	—	0.7	—
Total liabilities	$ —	$ (0.7)	$ —	$ —	$ 0.7	$ —
Evergy						
Assets						
Nuclear decommissioning trust[a]	$ 879.8	$ —	$ 764.2	$ 44.8	$ —	$ 70.8
Rabbi trusts	31.4	—	31.4	—	—	—
Self-insured health plan trust[c]	18.9	—	7.8	11.1	—	—
Derivative instruments - commodity contracts[b]						
Power	45.7	(22.7)	11.7	40.5	16.2	—
Natural gas	1.3	(17.7)	18.9	0.1	—	—
Total derivative assets	47.0	(40.4)	30.6	40.6	16.2	—
Total assets	977.1	(40.4)	834.0	96.5	16.2	70.8
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	43.5	(12.2)	4.5	44.2	7.0	—
Natural gas	2.3	(17.7)	19.9	0.1	—	—
Total derivative liabilities	45.8	(29.9)	24.4	44.3	7.0	—
Total liabilities	$ 45.8	$ (29.9)	$ 24.4	$ 44.3	$ 7.0	$ —

[a] With the exception of investments measured at NAV, fair value is based on quoted market prices of the investments held by the trust and/or valuation models.

[b] Derivative instruments classified as Level 1 consist of exchange-traded derivative instruments with fair value based on quoted market prices. Derivative instruments classified as Level 2 consist of non-exchange traded derivative instruments with observable forward curves and option contracts priced with models using observable inputs. Derivative instruments classified as Level 3 consist of non-exchange traded derivative instruments for which observable market data is not available to corroborate the valuation inputs and TCRs valued at the most recent auction price in the SPP Integrated Marketplace.

[c] Fair value is based on quoted market prices of the investments held by the trust. Debt securities classified as Level 1 are comprised of U.S. Treasury securities. Debt securities classified as Level 2 are comprised of corporate bonds, U.S. Agency, state and local obligations, and other asset-backed securities.

Certain Evergy and Evergy Kansas Central investments included in the table above are measured at NAV as they do not have readily determinable fair values. In certain situations, these investments may have redemption restrictions. The following table provides additional information on these Evergy and Evergy Kansas Central investments.

	December 31, 2025		December 31, 2024		December 31, 2025	
	Fair Value	Unfunded Commitments	Fair Value	Unfunded Commitments	Redemption Frequency	Length of Settlement
Evergy Kansas Central		(millions)				
Nuclear decommissioning trust:						
Domestic equity funds	$ 8.3	$ 1.3	$ 8.9	$ 1.3	(a)	(a)
Alternative investments fund[b]	49.6	—	45.6	—	Quarterly	65 days
Real estate securities fund[b]	16.8	—	16.3	—	Quarterly	65 days
Total Evergy investments at NAV	$ 74.7	$ 1.3	$ 70.8	$ 1.3		

[a] This investment is in four long-term private equity funds that do not permit early withdrawal. Investments in these funds cannot be distributed until the underlying investments have been liquidated, which may take years from the date of initial liquidation. All funds have begun to make distributions.
[b] There is a holdback on final redemptions.

The Evergy Companies hold equity and debt investments classified as securities in various trusts including for the purposes of funding the decommissioning of Wolf Creek and for the benefit of certain retired executive officers of Evergy Kansas Central. The Evergy Companies record net realized and unrealized gains and losses on the nuclear decommissioning trusts in regulatory liabilities on their consolidated balance sheets and record net realized and unrealized gains and losses on the Evergy Companies' rabbi trusts in the consolidated statements of income and comprehensive income.

The following table summarizes the net unrealized gains (losses) for the Evergy Companies' nuclear decommissioning trusts and rabbi trusts.

	2025	2024	2023
Evergy		(millions)	
Nuclear decommissioning trust - equity securities	$ 61.9	$ 89.3	80.4
Nuclear decommissioning trust - debt securities	2.3	(1.1)	2.7
Rabbi trusts - equity securities	2.2	0.4	2.4
Total	$ 66.4	$ 88.6	$ 85.5
Evergy Kansas Central			
Nuclear decommissioning trust - equity securities	$ (3.4)	$ 31.1	28.3
Rabbi trust - equity securities	1.8	0.4	2.0
Total	$ (1.6)	$ 31.5	$ 30.3
Evergy Metro			
Nuclear decommissioning trust - equity securities	$ 65.3	$ 58.2	52.1
Nuclear decommissioning trust - debt securities	2.3	(1.1)	2.7
Total	$ 67.6	$ 57.1	$ 54.8

15. COMMITMENTS AND CONTINGENCIES

Environmental Matters

Set forth below are descriptions of contingencies related to environmental matters that may impact the Evergy Companies' operations or their financial results. Management's assessment of these contingencies, which are based on federal and state statutes and regulations, and regulatory agency and judicial interpretations and actions, has evolved over time. These laws, regulations, interpretations and actions can also change, restrict or otherwise impact the Evergy Companies' operations or financial results. The failure to comply with these laws, regulations, interpretations and actions could result in the assessment of administrative, civil and criminal penalties and the

imposition of remedial requirements. The Evergy Companies believe that all their operations are in substantial compliance with current federal, state and local environmental standards.

There are a variety of final and proposed laws and regulations that could have a material adverse effect on the Evergy Companies' operations and consolidated financial results. Due in part to the complex nature of environmental laws and regulations, the Evergy Companies are unable to assess the impact of potential changes that may develop with respect to the environmental contingencies described below.

Ozone Interstate Transport State Implementation Plans (ITSIP)

In 2015, the EPA lowered the Ozone National Ambient Air Quality Standards (NAAQS) from 75 ppb to 70 ppb. States were required to submit ITSIPs in 2018 to comply with the "Good Neighbor Provision" of the Clean Air Act (CAA) as it applies to the revised NAAQS. The EPA did not act on these ITSIP submissions by the deadline established in the CAA and entered consent decrees establishing deadlines for the EPA to take final action on various ITSIPs. In February 2022, the EPA published a proposed rule to disapprove the ITSIPs submitted by nineteen states including Missouri and Oklahoma. In April 2022, the EPA published an approval of the Kansas ITSIP in the Federal Register. The Missouri Department of Natural Resources (MDNR) submitted a supplemental ITSIP to the EPA in November 2022. In February 2023, the EPA published a final rule disapproving the ITSIPs submitted by nineteen states, including the final disapproval of the Missouri and Oklahoma ITSIPs. In April 2023, the Attorneys General of Missouri and Oklahoma filed Petitions for Review in the U.S. Court of Appeals for the Eighth Circuit (Eighth Circuit) and the U.S. Court of Appeals for the Tenth Circuit (Tenth Circuit), respectively, challenging the EPA's disapproval. In May 2023, the Eighth Circuit granted a stay of the EPA's disapproval of the Missouri ITSIP. Similarly, in July 2023, the Tenth Circuit granted a stay of the EPA's disapproval of the Oklahoma ITSIP. In August 2024, the EPA published in the Federal Register a proposed rule to disapprove the supplemental ITSIP that Missouri submitted in November 2022. In January 2024, the EPA proposed to disapprove the previously-approved ITSIP for Kansas and ITSIPs submitted by four other states. To date, the EPA has not taken final action in this rulemaking. Disapproval of ITSIPs provides the EPA with authority to implement an interstate transport federal implementation plan (ITFIP) to replace them. As discussed below, the EPA has proposed to reevaluate and approve previously disapproved ITSIP submissions for five states, including Kansas. In the event that the ITSIPs for Missouri, Oklahoma and Kansas were disapproved and the EPA's ITFIP took effect, the impact on the Evergy Companies' operations and the cost to comply could be material.

Ozone Interstate Transport Federal Implementation Plans

In April 2022, the EPA published in the Federal Register the proposed ITFIP to resolve outstanding "Good Neighbor" obligations with respect to the 2015 Ozone NAAQS for twenty-six states including Missouri and Oklahoma. This ITFIP would establish a revised Cross-State Air Pollution Rule (CSAPR) ozone season nitrogen oxide (NOx) emissions trading program for Electric Generating Units (EGUs) beginning in 2023 and would limit ozone season NOx emissions from certain industrial stationary sources beginning in 2026. The proposed rule would also establish a new daily backstop NOx emissions rate limit for applicable coal-fired units larger than 100 MW, as well as unit-specific NOx emission rate limits for certain industrial emission units and would feature "dynamic" adjustments of emission budgets for EGUs beginning with ozone season 2025. The proposed ITFIP included reductions to the state ozone season NOx budgets for Missouri and Oklahoma beginning in 2023 with additional reductions in future years. The Evergy Companies provided formal comments as part of the rulemaking process. In March 2023, the EPA issued the final ITFIPs for twenty-three states, including Missouri and Oklahoma, which included reduced ozone season NOx budgets for EGUs in Missouri, Oklahoma and other states, and included other features and requirements that were in the proposed version of the rule. Because the EPA's authority to impose an ITFIP for a state is triggered by the state's failure to submit an ITSIP addressing NAAQS by the statutory deadline or disapproval of an ITSIP, the EPA lacks authority under the CAA to impose an ITFIP on a state for which an ITSIP disapproval has been stayed by the courts. Accordingly, the EPA issued interim final rules staying the effectiveness of the ITFIP in both Missouri and Oklahoma while the stays issued by the Eighth and Tenth Circuits in the ITSIP disapproval cases remain in place. During this time, both states will continue to operate under the existing CSAPR program. While Kansas was not originally included in the ITFIP, in January 2024, the EPA issued a proposal to include Kansas in the ITFIP. In June 2024, the U.S. Supreme Court issued an order granting emergency motions for stay filed by state and industry petitioners of the final ITFIP pending further review of the ITFIP by the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit). In March 2025, the EPA announced plans

to end the Good Neighbor Rule for the 2015 Ozone NAAQS. In April 2025, the D.C. Circuit granted an EPA request to hold all challenges to the ITFIP in indefinite abeyance. In January 2026, the EPA published in the federal register a proposed "Phase 1" reconsideration rule addressing interstate transport requirements for six states, including Kansas. The EPA indicated they intend to address additional states, including Missouri, in a separate action. The Phase 1 proposal would reevaluate and approve previously disapproved ITSIP submissions for five states, including Kansas. As a result, Kansas would no longer be subject to the ITFIP if this rule is finalized. If the ITFIP ultimately takes effect as promulgated for Missouri, Kansas and Oklahoma following the pending litigation or the EPA is unable to end the program as proposed, the impact on the Evergy Companies' operations and the cost to comply could be material.

Particulate Matter National Ambient Air Quality Standards

In March 2024, the EPA published in the Federal Register the final rule which strengthens the primary annual $PM_{2.5}$ (particulate matter less than 2.5 microns in diameter) NAAQS by lowering the primary annual $PM_{2.5}$ NAAQS from 12.0 µg/m3 (micrograms per cubic meter) to 9.0 µg/m3. The final rule took effect in May 2024. In August 2024, the EPA released the $PM_{2.5}$ ambient monitor design values for calendar years 2021 through 2023. These design values are to be used by each state governor for recommending to the EPA attainment designations for their states. In February 2025, the Kansas Governor sent recommendations to the EPA to designate the entire state of Kansas as either attainment or attainment/unclassifiable for the 2024 annual $PM_{2.5}$ NAAQS. In March 2025, the EPA announced it plans to reconsider the 2024 $PM_{2.5}$ NAAQS. As a result of the EPA's plans to reconsider this NAAQS, the Missouri Governor delayed submitting area designations to the EPA. While the EPA is required to issue final designations for all states, including Kansas and Missouri, by February 2026, the issuance of final designations is in question based on the EPA's plans to reconsider this NAAQS. In November 2025, the EPA filed a motion requesting that the D.C. Circuit vacate the 2024 $PM_{2.5}$ NAAQS, asserting that the prior presidential administration's EPA failed to consider costs during its revision process and therefore did not conduct a thorough review, as required. Due to the uncertainty of the attainment status of portions of the service territory and potential reconsideration or court vacatur of the NAAQS, the Evergy Companies are unable to accurately assess the impacts on their operations or consolidated financial results, but the cost to comply with lower $PM_{2.5}$ NAAQS could be material.

Regional Haze Rule

In 1999, the EPA finalized the Regional Haze Rule which aims to restore national parks and wilderness areas to pristine conditions. The rule requires states in coordination with the EPA, the National Park Service, the U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment. There are 156 "Class I" areas across the U.S. that must be restored to pristine conditions by the year 2064. There are no Class I areas in Kansas, whereas Missouri has two: the Hercules-Glades Wilderness Area and the Mingo Wilderness Area. States must submit revisions to their Regional Haze Rule state implementation plans (SIPs) every ten years and the first round was due in 2007. For the second ten-year implementation period, the EPA issued a final rule revision in 2017 that allowed states to submit their SIP revisions by July 2021.

The Missouri SIP revision does not require any additional reductions from the Evergy Companies' generating units in the state. MDNR submitted the Missouri SIP revision to the EPA in August 2022, however, they failed to do so by the EPA's revised submittal deadline in August 2022. As a result, in August 2022, the EPA published "finding of failure" with respect to Missouri and fourteen other states for failing to submit their Regional Haze SIP revisions by the applicable deadline. This finding of failure established a two-year deadline for the EPA to issue a Regional Haze federal implementation plan (FIP) for each state unless the state submits and the EPA approves a revised SIP that meets all applicable requirements before the EPA issues the FIP. In July 2024, the EPA published in the Federal Register a proposal to partially approve and partially disapprove Missouri's Regional Haze SIP revision.

The Kansas SIP revision did not include any additional emission reductions by electric utilities based on the significant reductions that were achieved during the first implementation period. The Kansas Department of Health and Environment (KDHE) submitted the Kansas SIP revision in July 2021. In August 2024, the EPA issued the final disapproval of the Kansas SIP revision for failing to conduct a four-factor analysis for at least two emission sources in Kansas. In response to the August 2024 final disapproval, in October 2025, KDHE placed a

supplemental Kansas SIP revision on public notice, and no adverse comments were received. In this supplement, the KDHE performed additional analyses for two Kansas emission sources, including Evergy's La Cygne Station, and determined no additional requirements should be necessary for any Kansas emission source. In January 2026, the KDHE submitted the supplement to the EPA for their approval.

In March 2025, the EPA announced plans to restructure the Regional Haze Program and in October 2025, the EPA published a Notice of Proposed Advanced Rulemaking requesting comments to assist in the development of regulatory changes to the current Regional Haze Program. In December 2025, the EPA issued a final rule extending the SIP revision deadline for the third ten-year implementation period from July 2028 to July 2031. Due to uncertainty regarding the status of the Regional Haze Program and when or if a Kansas or Missouri revised SIP or FIP is finalized, the overall costs of implementing the rules could be material to the Evergy Companies.

Greenhouse Gases

Burning coal and other fossil fuels releases carbon dioxide (CO_2) and other gases referred to as greenhouse gases (GHG). Various regulations under the CAA limit CO_2 and other GHG emissions, and in addition, other measures are being imposed or offered by individual states, municipalities and regional agreements with the goal of reducing GHG emissions. In April 2024, the EPA finalized the GHG regulations and GHG guidelines that apply to new and existing fossil-fuel fired EGUs. The final GHG regulation establishes CO_2 limitations on emissions from new and reconstructed stationary combustion turbines. The GHG guidelines set CO_2 emission limitations for existing coal, oil and gas-fired steam generating units. For new and reconstructed stationary combustion turbines, the emission limitations were developed by applying the Best System of Emission Reduction (BSER) to three distinct subcategories (low load, intermediate load and base load) taking into consideration the annual capacity factor of the stationary combustion turbine. For intermediate and base load stationary combustion turbines, BSER is assumed to be the utilization of highly efficient combustion turbine technology. Base load stationary combustion turbines are also required to consider the emissions reduction associated with the application of carbon capture and sequestration (CCS) beginning in 2032. For existing coal-fired EGUs, the emission limitations were established by applying the BSER to two subcategories (medium and long-term). For medium-term existing coal-fired units, which are units retiring between 2032 and 2038, the BSER established emission limitation is based on co-firing natural gas beginning in 2030. For units operating in 2039 and after, BSER is the application of CCS starting in 2032. In July 2024, the D.C. Circuit denied motions of stay filed by various states, industry and trade organizations; however, the D.C. Circuit has ordered expedited review of the challenges to the final regulations and guidelines. In December 2024, a three-judge panel of the D.C. Circuit heard oral arguments on challenges to the merits of the rule. In March 2025, the EPA announced it plans to reconsider the GHG regulation and guidelines. While the EPA reconsiders the GHG regulation and guidelines, the D.C. Circuit granted an unopposed motion to hold the case challenging the merits of the rule in abeyance. In June 2025, the EPA published a proposed rule to repeal both the 2015 GHG emission standards for new fossil-fuel fired EGUs and the April 2024 GHG emission standards for new and existing fossil-fuel fired EGUs. In the same June 2025 proposed rule, the EPA included an alternative proposal to repeal the most burdensome requirements of the 2024 rule including the elimination of CCS as BSER. In February 2026, the EPA issued a final rule rescinding the 2009 GHG Endangerment Finding (Endangerment Finding). The Endangerment Finding applies to GHG emissions from new motor vehicles and also provides justification for declaring GHG emissions as a threat to public health and welfare, thereby establishing the basis for regulating GHG emission under the CAA. As a result of the rescission of the Endangerment Finding, there is no justification for continuing to regulate GHG emissions from the power sector.

Due to uncertainty regarding when each of these proposed rules will be finalized, and the ongoing and potential for judicial review, the Evergy Companies are unable to accurately assess the impacts on their operations or consolidated financial results, but the cost to comply could be material.

Regulation of Coal Combustion Residuals

In the course of operating their coal generation plants, the Evergy Companies produce CCRs, including fly ash, gypsum and bottom ash. The EPA published a rule to regulate CCRs in April 2015 that requires additional CCR handling, processing and storage equipment and closure of certain ash disposal units. In January 2022, the EPA published proposed determinations for facilities that filed closure extensions for unlined or clay-lined CCR units. These proposed determinations include various interpretations of the CCR regulations and compliance expectations

that may impact all owners of CCR units. These interpretations could require modified compliance plans such as different methods of CCR unit closure. Additionally, more stringent remediation requirements for units that are in corrective action or forced to go into corrective action are possible. The cost to comply with these proposed determinations by the EPA could be material.

In April 2024, the EPA finalized an expansion to the CCR regulations focused on legacy surface impoundments and historic placements of CCR. This regulation expands applicability of the 2015 CCR regulation to inactive landfills and beneficial use sites not previously regulated. Litigation could impact the timing or cost to comply. In March 2025, the EPA announced its plans to update regulations of CCRs, and in January 2026, finalized a rulemaking extending deadlines for compliance with various aspects of the CCR legacy rule. The EPA has indicated a second rulemaking modifying CCR requirements should be anticipated later in 2026, however specific details of any planned revisions have not been provided.

The Evergy Companies have recorded AROs for their current estimates for the closure of ash disposal ponds, landfills and other historical placements of CCR. The revision of these AROs may be required in the future due to information collected in the April 2024 CCR regulation's Facility Evaluation Reports (FERs), changes in existing CCR regulations, the results of groundwater monitoring of CCR units, changes in interpretation of existing CCR regulations or changes in the timing or cost to close ash disposal ponds and landfills. The revision of AROs for regulated operations has no income statement impact due to the deferral of the adjustments through a regulatory asset. If revisions to these AROs are necessary, the impact on the Evergy Companies' operations or consolidated financial results could be material.

Montrose Station CCRs

In 2025, three lawsuits, including one seeking class certification, were filed in the Circuit Court of Henry County, Missouri against Evergy Metro and two other defendants alleging unspecified damages resulting from the defendants' alleged unlawful and negligent spreading of CCRs associated with the Montrose Station coal ash landfill. Montrose Station was a coal-fired generating facility which was operated by Evergy Metro until its closure in 2018. The cases are at preliminary stages and Evergy and Evergy Metro are unable to assess the outcome or reasonably estimate any possible damages with respect to the claims. However, Evergy and Evergy Metro believe the claims are without merit and intend to vigorously defend themselves.

Nuclear Antitrust Class Action

In July 2025, a class action complaint was filed in the U.S. District Court for the District of Maryland alleging violations of the Sherman Antitrust Act in establishing wages for employees at nuclear facilities since 2003. The complaint names 28 defendants, including all 26 owner operators of nuclear facilities in the United States, or affiliated entities, including Wolf Creek Nuclear Operating Corporation, which operates Wolf Creek, a nuclear facility in Kansas. Evergy indirectly owns 94% of Wolf Creek, with Evergy Kansas Central and Evergy Metro each owning 47% of the nuclear facility. This case is at a preliminary stage and the Evergy Companies are unable to assess the outcome or reasonably estimate any possible damages with respect to the claims.

Nuclear Insurance

Nuclear liability, property and accidental outage insurance is maintained for Wolf Creek. These policies contain certain industry standard terms, conditions and exclusions, including, but not limited to, ordinary wear and tear and war. An industry aggregate limit of approximately $3.2 billion for nuclear events (approximately $1.8 billion of non-nuclear events) plus any reinsurance, indemnity or any other source recoverable by Nuclear Electric Insurance Limited (NEIL), provider of property and accidental outage insurance, exists for acts of terrorism affecting Wolf Creek or any other NEIL insured plant within 12 months from the date of the first act. In addition, participation is required in industry-wide retrospect assessment programs as discussed below.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, liability insurance includes coverage against public nuclear liability claims resulting from nuclear incidents to the required limit of public liability, which is approximately $16.3 billion. This limit of liability consists of the maximum available commercial insurance of $0.5 billion and the remaining $15.8 billion is provided through mandatory participation in an industry-wide retrospective assessment program. Under

this retrospective assessment program, the owners of Wolf Creek are jointly and severally subject to an assessment of up to approximately $165.9 million (Evergy's share is $156.0 million and each of Evergy Kansas Central's and Evergy Metro's is $78.0 million), payable at no more than approximately $24.7 million (Evergy's share is $23.2 million and each of Evergy Kansas Central's and Evergy Metro's is $11.6 million) per incident per year per reactor for any commercial U.S. nuclear reactor qualifying incident. Both the total and yearly assessment is subject to an inflationary adjustment based on the Consumer Price Index and applicable premium taxes. In addition, the U.S. Congress could impose additional revenue-raising measures to pay claims.

Nuclear Property and Accidental Outage Insurance

The owners of Wolf Creek carry decontamination liability, nuclear property damage and premature nuclear decommissioning liability insurance for Wolf Creek totaling approximately $2.8 billion. Insurance coverage for non-nuclear property damage accidents total approximately $1.0 billion. In the event of an extraordinary nuclear accident, insurance proceeds must first be used for reactor stabilization and site decontamination in accordance with a plan mandated by the Nuclear Regulatory Commission (NRC). The Evergy Companies' share of any remaining proceeds can be used to pay for property damage or, if certain requirements are met, including decommissioning the plant, toward a shortfall in the nuclear decommissioning trust. The owners also carry additional insurance with NEIL to help cover costs of replacement power and other extra expenses incurred during a prolonged outage resulting from accidental property damage at Wolf Creek. If significant losses were incurred at any of the nuclear plants insured under the current NEIL policies, the owners of Wolf Creek may be subject to retrospective assessments under the current policies of approximately $27.9 million (Evergy's share is $26.2 million and each of Evergy Kansas Central's and Evergy Metro's is $13.1 million).

Nuclear Insurance Considerations

Although the Evergy Companies maintain various insurance policies to provide coverage for potential losses and liabilities resulting from an accident or an extended outage, the insurance coverage may not be adequate to cover the costs that could result from a catastrophic accident or extended outage at Wolf Creek. Any substantial losses not covered by insurance, to the extent not recoverable in prices, would have a material effect on the Evergy Companies' consolidated financial results.

Contractual Commitments

The Evergy Companies' contractual commitments for fuel, power and new generation projects as of December 31, 2025 are detailed in the following tables. See Notes 9, 12 and 21 for information regarding pension, long-term debt and lease commitments, respectively.

Evergy

	2026	2027	2028	2029	2030	After 2030	Total
Purchase commitments				(millions)			
Fuel	$ 313.0	$ 202.9	$ 194.7	$ 181.0	$ 93.2	$ 384.4	$ 1,369.2
Power	73.7	83.9	104.9	123.8	105.6	176.1	668.0
New generation projects	1,023.9	1,070.7	833.5	192.3	59.7	3.8	3,183.9
Total contractual commitments	$ 1,410.6	$ 1,357.5	$ 1,133.1	$ 497.1	$ 258.5	$ 564.3	$ 5,221.1

Evergy Kansas Central

	2026	2027	2028	2029	2030	After 2030	Total
Purchase commitments				(millions)			
Fuel	$ 182.8	$ 117.7	$ 109.4	$ 97.4	$ 50.8	$ 213.6	$ 771.7
Power	1.4	1.5	12.3	20.0	19.1	44.7	99.0
New generation projects	342.3	497.7	348.2	59.1	15.9	1.0	1,264.2
Total contractual commitments	$ 526.5	$ 616.9	$ 469.9	$ 176.5	$ 85.8	$ 259.3	$ 2,134.9

Evergy Metro

	2026	2027	2028	2029	2030	After 2030	Total
Purchase commitments				(millions)			
Fuel	$ 110.8	$ 70.7	$ 73.8	$ 75.2	$ 36.7	$ 142.2	$ 509.4
Power	29.2	29.2	29.2	29.2	29.2	50.1	196.1
Total contractual commitments	$ 140.0	$ 99.9	$ 103.0	$ 104.4	$ 65.9	$ 192.3	$ 705.5

Fuel commitments consist of commitments for nuclear fuel and coal in addition to coal and natural gas transportation costs. Power commitments consist of certain commitments for renewable energy under power purchase agreements, capacity purchases and firm transmission service. New generation project commitments consist of contractual obligations related to natural gas and renewable plant investments. See "Natural Gas Plant Investments" and "Renewable Plant Investments" in Note 1 for additional information on new generation construction projects.

16. GUARANTEES

In the ordinary course of business, Evergy and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include, for example, guarantees and letters of credit. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiary's intended business purposes. The majority of these agreements guarantee Evergy's own future performance, so a liability for the fair value of the obligation is not recorded.

As of December 31, 2025, Evergy has provided $786.3 million of credit support for certain of its subsidiaries as follows:

- Evergy direct guarantees to Evergy Kansas Central and Evergy Metro counterparties for certain fuel supply contracts totaling $76.3 million, with expiration dates ranging from 2027 to 2031; and
- Evergy's guarantee of Evergy Missouri West long-term debt totaling $710.0 million, which includes debt with maturity dates ranging from 2031 to 2043.

None of the guaranteed obligations are subject to default or prepayment if Evergy Missouri West's credit ratings were downgraded.

17. RELATED PARTY TRANSACTIONS AND RELATIONSHIPS

In the normal course of business, Evergy Kansas Central, Evergy Metro and Evergy Missouri West engage in related party transactions with one another. In addition, Evergy Kansas Central and Evergy Missouri West are currently engaged in the construction of jointly-owned generation facilities. A summary of these related party transactions and the amounts associated with them is provided below.

Jointly-Owned Plants and Shared Services

Employees of Evergy Kansas Central and Evergy Metro manage Evergy Missouri West's business and operate its facilities at cost, including Evergy Missouri West's 18% ownership interest in Evergy Metro's Iatan Nos. 1 and 2. Employees of Evergy Kansas Central manage Jeffrey Energy Center (JEC) and operate its facilities at cost, including Evergy Missouri West's 8% ownership interest in JEC. Employees of Evergy Metro manage La Cygne Station and operate its facilities at cost, including Evergy Kansas Central's 50% interest in La Cygne Station. Employees of Evergy Metro and Evergy Kansas Central also provide one another with shared service support, including costs related to human resources, information technology, accounting and legal services.

The operating expenses and capital costs billed for jointly-owned plants and shared services are detailed in the following table.

	2025	2024	2023
		(millions)	
Evergy Kansas Central billings to Evergy Missouri West	$ 213.8	$ 29.6	$ 33.0
Evergy Metro billings to Evergy Missouri West	108.1	111.3	124.6
Evergy Kansas Central billings to Evergy Metro	52.1	46.9	48.4
Evergy Metro billings to Evergy Kansas Central	128.9	144.6	132.9

Related Party Net Receivables and Payables

The following table summarizes Evergy Kansas Central's and Evergy Metro's related party net receivables and payables.

	December 31	
	2025	2024
Evergy Kansas Central	(millions)	
Net payable to Evergy	$ (13.3)	$ (13.4)
Net receivable from (payable to) Evergy Metro	10.6	(22.9)
Net receivable from Evergy Missouri West	34.6	23.0
Evergy Metro		
Net receivable from Evergy	$ 16.5	$ 16.8
Net receivable from (payable to) Evergy Kansas Central	(10.6)	22.9
Net receivable from Evergy Missouri West	96.2	86.2

Money Pool

Evergy Kansas Central, Evergy Metro and Evergy Missouri West are authorized to participate in the Evergy, Inc. money pool, which is an internal financing arrangement in which funds may be lent on a short-term basis between Evergy Kansas Central, Evergy Metro, Evergy Missouri West and Evergy, Inc. Evergy, Inc. can lend but not borrow under the money pool.

As of December 31, 2025 and December 31, 2024, Evergy Kansas Central and Evergy Metro had no outstanding receivables or payables under the money pool.

Tax Allocation Agreement

Evergy files a consolidated federal income tax return as well as unitary and combined income tax returns in several state jurisdictions with Kansas and Missouri being the most significant. Income taxes for consolidated or combined subsidiaries are allocated to the subsidiaries based on separate company computations of income or loss. The following table summarizes Evergy Kansas Central's and Evergy Metro's income taxes receivable from (payable to) Evergy.

	December 31	
	2025	2024
Evergy Kansas Central	(millions)	
Income taxes receivable from (payable to) Evergy	$ (14.3)	$ 11.4
Evergy Metro		
Income taxes payable to Evergy	$ —	$ (10.0)

18. SHAREHOLDERS' EQUITY

Evergy's authorized capital stock consists of 600 million shares of common stock, without par value, and 12 million shares of Preference Stock, without par value.

Evergy Registration Statements
In August 2024, Evergy filed an automatic shelf registration statement on Form S-3 with the Securities and Exchange Commission (SEC). Under this Form S-3, which is uncapped, Evergy may issue debt and other securities, including common stock, in the future with the amounts, prices and terms to be determined at the time of future offerings. The automatic registration statement was filed to replace a similar Form S-3 upon expiration of its three-year term. The shelf registration statement expires in August 2027.

In March 2024, Evergy registered shares of its common stock with the SEC for its Dividend Reinvestment and Direct Stock Purchase Plan. Shares issued under the plan may be either newly issued shares or shares purchased on the open market.

Evergy has registered shares of its common stock with the SEC for the Evergy, Inc. 401(k) Savings Plan. Shares issued under the plan may be either newly issued shares or shares purchased on the open market.

ATM Program (At-the-Market Program)
In May 2025, Evergy entered into an equity distribution agreement, pursuant to which Evergy may sell, from time to time, up to an aggregate of $1.2 billion of its common stock through an ATM Program, which may utilize forward sales agreements. Evergy subsequently entered into forward sale agreements under the ATM program and as of December 31, 2025, the ATM Program had approximately $1.1 billion of common stock available for issuance.

The forward sale agreements outstanding as of December 31, 2025, can be settled at Evergy’s discretion on or prior to dates ranging from March 2027 to October 2027. On a settlement date or dates, if Evergy elects to physically settle a forward sale agreement, Evergy will issue shares of common stock to the counterparties at the then-applicable forward sale price. The initial forward sale price for the outstanding agreements ranged from $71.29 to $73.34, with a weighted average initial forward sale price of $72.50. The initial forward sale price is subject to adjustment on a daily basis based on an interest rate factor and decreased on certain dates by predetermined amounts to reflect expected dividend payments. The forward sale agreements will be physically settled unless Evergy elects to settle in cash or to net share settle. At December 31, 2025, Evergy could have settled the forward sale agreements with physical delivery of 1.7 million shares of common stock to the respective counterparties in exchange for cash of $123.6 million. Alternatively, the forward sale agreements could have also been settled at December 31, 2025, with delivery of approximately $0.6 million of cash if Evergy elected net cash settlement.

Evergy has not received any proceeds related to the outstanding forward sale agreements. The forward sale agreements have been classified as equity transactions.

Dividend Restrictions
Evergy depends on its subsidiaries to pay dividends on its common stock. The Evergy Companies have certain restrictions stemming from statutory requirements, corporate organizational documents, covenants and other conditions that could affect dividend levels or the ability to pay dividends.

The KCC order authorizing the merger that created Evergy requires Evergy to maintain consolidated common equity of at least 35% of total consolidated capitalization.

Under the Federal Power Act, Evergy Kansas Central, Evergy Metro and Evergy Missouri West generally can pay dividends only out of retained earnings. Certain conditions in the MPSC and KCC orders authorizing the merger that created Evergy also require Evergy Kansas Central and Evergy Metro to maintain consolidated common equity of at least 40% of total capitalization. Other conditions in the MPSC and KCC merger orders require Evergy Kansas Central, Evergy Metro and Evergy Missouri West to maintain credit ratings of at least investment grade. If Evergy Kansas Central's, Evergy Metro's or Evergy Missouri West's credit ratings are downgraded below the

investment grade level as a result of their affiliation with Evergy or any of Evergy's affiliates, the impacted utility shall not pay a dividend to Evergy without KCC or MPSC approval or until the impacted utility's investment grade credit rating has been restored.

The master credit facility of Evergy, Evergy Kansas Central, Evergy Metro and Evergy Missouri West and the note purchase agreements for certain Evergy Missouri West senior notes contain covenants requiring the respective company to maintain a consolidated indebtedness to consolidated total capitalization ratio of not more than 0.65 to 1.00.

The Evergy, Inc. Junior Subordinated Notes issued in December 2024 permit Evergy to defer the payment of interest under certain circumstances. Making such an election would restrict Evergy's ability to declare or pay dividends, among other restrictions. As of December 31, 2025, Evergy has not elected to defer the payment of interest under the terms of the Junior Subordinated Notes.

As of December 31, 2025, Evergy had a retained earnings restriction of $394.8 million, Evergy Kansas Central had a retained earnings restriction of $517.8 million and Evergy Metro had a retained earnings restriction of $617.8 million. As of December 31, 2025, Evergy's subsidiaries had restricted net assets of approximately $6.7 billion. These restrictions are not expected to affect the Evergy Companies' ability to pay dividends at the current level for the foreseeable future.

19. VARIABLE INTEREST ENTITIES

In determining the primary beneficiary of a VIE, the Evergy Companies assess the entity's purpose and design, including the nature of the entity's activities and the risks that the entity was designed to create and pass through to its variable interest holders. A reporting enterprise is deemed to be the primary beneficiary of a VIE if it has (a) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses or right to receive benefits from the VIE that could potentially be significant to the VIE. The primary beneficiary of a VIE is required to consolidate the VIE.

All involvement with entities by the Evergy Companies is assessed to determine whether such entities are VIEs and, if so, whether or not the Evergy Companies are the primary beneficiaries of the entities. The Evergy Companies also continuously assess whether they are the primary beneficiary of the VIE with which they are involved. Prospective changes in facts and circumstances may cause identification of the primary beneficiary to be reconsidered.

Evergy Missouri West Storm Funding

In 2022, Evergy Missouri West created Evergy Missouri West Storm Funding solely for the purpose of recovering extraordinary fuel and purchased power costs incurred as part of the February 2021 winter weather event. In February 2024, Evergy Missouri West Storm Funding issued, at a discount, $331.1 million of 5.10% Securitized Bonds with a final payment scheduled for 2038, maturing in 2040. The obligations of Evergy Missouri West Storm Funding's Securitized Bonds are repaid through charges imposed on customers in Evergy Missouri West's service territory and collected by Evergy Missouri West on behalf of Evergy Missouri West Storm Funding. Creditors of Evergy Missouri West have no recourse to any assets or revenues of Evergy Missouri West Storm Funding, and the bondholders have no recourse to the general credit of Evergy Missouri West.

Evergy Missouri West Storm Funding is considered a VIE. Evergy Missouri West is the primary beneficiary of the VIE primarily because, as described above, Evergy Missouri West has the power to direct the activities of Evergy Missouri West Storm Funding that most significantly impact economic performance and Evergy Missouri West has the obligation to absorb losses or the right to receive benefits from Evergy Missouri West Storm Funding that could potentially be significant. Therefore, Evergy Missouri West consolidates Evergy Missouri West Storm Funding.

The following table summarizes the impact of Evergy Missouri West Storm Funding on Evergy's consolidated balance sheet as of December 31, 2025 and 2024.

	December 31	
	2025	2024
Evergy	(millions)	
Current assets		
Regulatory assets	$ 16.7	$ 15.9
Other	4.8	5.4
Other assets		
Regulatory assets	277.9	294.5
Other	1.6	1.7
Current liabilities		
Current maturities of long-term debt	17.0	16.2
Accrued interest	1.3	1.3
Long-term liabilities		
Long-term debt, net	279.2	295.7

50% Interest in La Cygne Unit 2

Under an agreement that expires in September 2029, Evergy Kansas Central entered into a sale-leaseback transaction with a trust under which the trust purchased Evergy Kansas Central's 50% interest in La Cygne Unit 2 and subsequently leased it back to Evergy Kansas Central. The trust was financed with an equity contribution from an owner participant and debt issued by the trust. The trust was created specifically to purchase the 50% interest in La Cygne Unit 2 and lease it back to Evergy Kansas Central and does not hold any other assets. Evergy Kansas Central meets the requirements to be considered the primary beneficiary of the trust. In determining the primary beneficiary of the trust, Evergy Kansas Central concluded that the activities of the trust that most significantly impact its economic performance and that Evergy Kansas Central has the power to direct include (1) the operation and maintenance of the 50% interest in La Cygne Unit 2 and (2) Evergy Kansas Central's ability to exercise a purchase option at the end of the agreement at the lesser of fair value or a fixed amount. Evergy Kansas Central has the potential to receive benefits from the trust that could potentially be significant if the fair value of the 50% interest in La Cygne Unit 2 at the end of the agreement is greater than the fixed amount.

As of December 31, 2025 and 2024, Evergy and Evergy Kansas Central recorded $119.4 million and $126.5 million, respectively, to property, plant and equipment, net, on their consolidated balance sheets related to the VIE described above.

The assets of the VIE can be used only to settle obligations of the VIE and the VIE's debt holders have no recourse to the general credit of Evergy and Evergy Kansas Central. Evergy and Evergy Kansas Central have not provided financial or other support to the VIE and are not required to provide such support. Evergy and Evergy Kansas Central did not record any gain or loss upon the initial consolidation of the VIE.

20. TAXES

Components of income tax expense are detailed in the following tables.

Evergy

	2025	2024	2023
Current income taxes		(millions)	
Federal	$ 1.8	$ 30.9	$ 25.3
State	7.2	7.7	6.9
Total	9.0	38.6	32.2
Deferred income taxes			
Federal	52.4	30.0	10.2
State	(24.5)	(31.4)	(21.7)
Total	27.9	(1.4)	(11.5)
Investment tax credit			
Deferral	—	—	2.2
Amortization	(7.0)	(7.2)	(7.3)
Total	(7.0)	(7.2)	(5.1)
Income tax expense	$ 29.9	$ 30.0	$ 15.6

Evergy Kansas Central

	2025	2024	2023
Current income taxes		(millions)	
Federal	$ 27.0	$ 6.2	$ 27.8
State	7.2	4.7	4.7
Total	34.2	10.9	32.5
Deferred income taxes			
Federal	(5.9)	16.4	(29.3)
State	(8.3)	(11.3)	(7.4)
Total	(14.2)	5.1	(36.7)
Investment tax credit			
Deferral	—	—	2.2
Amortization	(3.7)	(3.8)	(3.9)
Total	(3.7)	(3.8)	(1.7)
Income tax expense (benefit)	$ 16.3	$ 12.2	$ (5.9)

Evergy Metro

	2025	2024	2023
Current income taxes		(millions)	
Federal	$ 18.3	$ 37.7	$ 13.2
State	1.5	3.6	3.7
Total	19.8	41.3	16.9
Deferred income taxes			
Federal	38.3	15.8	33.6
State	(10.7)	(13.0)	(7.8)
Total	27.6	2.8	25.8
Investment tax credit amortization	(3.2)	(3.2)	(3.5)
Income tax expense	$ 44.2	$ 40.9	$ 39.2

Effective Income Tax Rates

Effective income tax rates reflected in the financial statements and the reasons for their differences from the statutory federal rates are detailed in the following tables.

Evergy

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
	(millions, except percentages)					
Federal statutory income tax	$ 188.5	21.0 %	$ 192.3	21.0 %	$ 159.4	21.0 %
State and local income taxes						
State income taxes[a]	12.1	1.4 %	7.1	0.8 %	5.2	0.7 %
Amortization of state excess deferred income taxes	(27.2)	(3.0)%	(27.2)	(3.0)%	(16.1)	(2.1)%
Tax Credits						
Energy-related tax credits	(57.5)	(6.4)%	(59.8)	(6.5)%	(44.3)	(5.8)%
Other tax credits	(2.2)	(0.2)%	(4.1)	(0.5)%	(3.1)	(0.4)%
Nontaxable or nondeductible items						
Corporate-owned life insurance	(10.9)	(1.2)%	(11.9)	(1.3)%	(14.2)	(1.9)%
Other permanent differences	(2.9)	(0.3)%	(3.3)	(0.4)%	(2.1)	(0.3)%
Effects of ratemaking						
Amortization of investment tax credits	(5.3)	(0.6)%	(5.4)	(0.6)%	(5.6)	(0.7)%
Amortization of federal excess deferred income taxes	(61.2)	(6.8)%	(59.9)	(6.5)%	(62.1)	(8.2)%
Flow through for plant related differences	1.0	0.1 %	5.2	0.6 %	1.5	0.2 %
Other adjustments	(4.5)	(0.7)%	(3.0)	(0.3)%	(3.0)	(0.5)%
Income tax expense and effective income tax rate	$ 29.9	3.3 %	$ 30.0	3.3 %	$ 15.6	2.0 %

[a] State income taxes in Missouri and Kansas make up the majority (greater than 50%) of the tax effect in this category.

Evergy Kansas Central

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
	(millions, except percentages)					
Federal statutory income tax	$ 121.7	21.0 %	$ 121.2	21.0 %	$ 79.5	21.0 %
State and local income taxes						
State income taxes[a]	7.7	1.3 %	3.4	0.6 %	1.5	0.4 %
Amortization of state excess deferred income taxes	(9.9)	(1.7)%	(10.0)	(1.7)%	(2.8)	(0.7)%
Tax Credits						
Energy-related tax credits	(57.0)	(9.8)%	(59.4)	(10.3)%	(43.7)	(11.5)%
Other tax credits	(0.7)	(0.1)%	(0.7)	(0.1)%	(0.7)	(0.2)%
Nontaxable or nondeductible items						
Corporate-owned life insurance	(10.4)	(1.8)%	(11.4)	(2.0)%	(13.7)	(3.6)%
Other permanent differences	(4.3)	(0.7)%	(4.4)	(0.8)%	(3.9)	(1.0)%
Effects of ratemaking						
Amortization of investment tax credits	(2.0)	(0.3)%	(2.1)	(0.4)%	(2.2)	(0.6)%
Amortization of federal excess deferred income taxes	(26.2)	(4.5)%	(22.8)	(3.9)%	(23.5)	(6.2)%
Flow through for plant related differences	(1.2)	(0.2)%	2.2	0.4 %	4.4	1.2 %
Other adjustments	(1.4)	(0.4)%	(3.8)	(0.7)%	(0.8)	(0.4)%
Income tax expense (benefit) and effective income tax rate	$ 16.3	2.8 %	$ 12.2	2.1 %	$ (5.9)	(1.6)%

[a] State income taxes in Missouri and Kansas make up the majority (greater than 50%) of the tax effect in this category.

Evergy Metro

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
	(millions, except percentages)					
Federal statutory income tax	$ 76.6	21.0 %	$ 76.7	21.0 %	$ 78.0	21.0 %
State and local income taxes						
State income taxes[a]	4.0	1.1 %	3.8	1.0 %	4.2	1.1 %
Amortization of state excess deferred income taxes	(11.2)	(3.1)%	(11.2)	(3.1)%	(7.5)	(2.0)%
Tax Credits						
Other tax credits	(1.8)	(0.5)%	(3.6)	(1.0)%	(2.7)	(0.7)%
Nontaxable or nondeductible items						
Other permanent differences	1.1	0.3 %	0.3	0.1 %	1.4	0.4 %
Effects of ratemaking						
Amortization of investment tax credits	(3.2)	(0.9)%	(3.2)	(0.9)%	(3.5)	(0.9)%
Amortization of federal excess deferred income taxes	(22.0)	(6.0)%	(23.3)	(6.4)%	(30.1)	(8.1)%
Flow through for plant related differences	2.0	0.6 %	2.7	0.7 %	1.9	0.5 %
Other adjustments	(1.3)	(0.4)%	(1.3)	(0.2)%	(2.5)	(0.7)%
Income tax expense and effective income tax rate	$ 44.2	12.1 %	$ 40.9	11.2 %	$ 39.2	10.6 %

[a] State income taxes in Missouri and Kansas make up the majority (greater than 50%) of the tax effect in this category.

Income Taxes Paid

Income taxes paid, net of refunds received, disaggregated between federal and state are detailed in the following tables.

Evergy

	2025	2024	2023
		(millions)	
Federal income taxes	$ 5.9	$ 31.0	$ 28.7
State income taxes			
Missouri	—	7.0	10.5
Kansas	—	(0.1)	(5.0)
Other states	0.2	0.1	0.2
Total state income tax paid, net of refunds	0.2	7.0	5.7
Total income taxes paid, net of refunds	$ 6.1	$ 38.0	$ 34.4

Evergy Kansas Central

	2025	2024	2023
		(millions)	
Federal income taxes	$ 9.0	$ 7.0	$ 48.5
State income taxes			
Missouri	1.4	3.6	5.8
Kansas	(1.9)	—	—
Other states	0.1	0.1	0.1
Total state income tax paid, net of refunds	(0.4)	3.7	5.9
Total income taxes paid, net of refunds	$ 8.6	$ 10.7	$ 54.4

Evergy Metro

	2025	2024	2023
		(millions)	
Federal income taxes	$ 29.8	$ 34.9	$ 6.4
State income taxes			
Missouri	0.1	3.6	2.7
Kansas	(0.3)	(0.1)	0.5
Other states	0.1	0.1	0.2
Total state income tax paid, net of refunds	(0.1)	3.6	3.4
Total income taxes paid, net of refunds	$ 29.7	$ 38.5	$ 9.8

Deferred Income Taxes

The tax effects of major temporary differences resulting in deferred income tax assets (liabilities) in the consolidated balance sheets is in the following table.

	December 31					
	2025			2024		
	Evergy	Evergy Kansas Central	Evergy Metro	Evergy	Evergy Kansas Central	Evergy Metro
Deferred tax assets:			(millions)			
Tax credit carryforward	$ 572.8	$ 412.4	$ 159.1	$ 393.2	$ 296.5	$ 95.3
Income taxes refundable to customers, net	323.3	169.1	126.6	308.2	160.5	115.7
Deferred employee benefit costs	92.9	37.7	59.2	98.4	42.4	61.6
Net operating loss carryforward	4.6	—	—	4.4	—	—
Deferred state income taxes	123.5	92.1	29.5	132.2	95.7	32.8
Accrued liabilities	214.8	101.2	81.2	198.0	92.6	73.8
Other regulatory liabilities	69.5	54.0	8.5	92.4	62.8	8.0
Other	94.9	43.9	23.8	99.6	46.4	25.8
Total deferred tax assets before valuation allowance	1,496.3	910.4	487.9	1,326.4	796.9	413.0
Valuation allowances	(7.2)	(2.7)	—	(6.9)	(2.7)	—
Total deferred tax assets, net	1,489.1	907.7	487.9	1,319.5	794.2	413.0
Deferred tax liabilities:						
Plant-related	(2,974.9)	(1,463.3)	(1,079.5)	(2,844.9)	(1,407.6)	(1,030.5)
Deferred employee benefit costs	(0.6)	—	—	(0.5)	—	—
ARO regulatory assets	(194.0)	(85.3)	(75.5)	(177.2)	(76.4)	(68.4)
Acquisition premium	(31.0)	(31.0)	—	(34.2)	(34.2)	—
Other regulatory assets	(227.6)	(38.7)	(55.9)	(200.6)	(31.3)	(39.5)
Other	(81.7)	(50.3)	(20.8)	(97.8)	(50.3)	(29.9)
Total deferred tax liabilities	(3,509.8)	(1,668.6)	(1,231.7)	(3,355.2)	(1,599.8)	(1,168.3)
Net deferred income tax liabilities	$ (2,020.7)	$ (760.9)	$ (743.8)	$ (2,035.7)	$ (805.6)	$ (755.3)

Tax Credit Carryforwards

As of December 31, 2025 and 2024, Evergy had $567.9 million and $388.3 million, respectively, of federal general business income tax credit carryforwards. As of December 31, 2025 and 2024, Evergy Kansas Central had $407.5 million and $291.6 million, respectively, of federal general business income tax credit carryforwards. As of December 31, 2025 and 2024, Evergy Metro had $159.1 million and $95.3 million, respectively, of federal general business income tax credit carryforwards. The carryforwards for Evergy, Evergy Kansas Central and Evergy Metro relate primarily to PTCs and research and development tax credits and expire in the years 2026 to 2045.

The Evergy Companies' federal general business income tax credit carryforwards include PTCs related to the generation of electricity from nuclear energy. As of December 31, 2025, Evergy, Evergy Kansas Central and Evergy Metro had $263.1 million, $130.5 million and $132.6 million, respectively, of tax credits from the generation of electricity from nuclear energy included in the production tax credits carryforwards. Beginning in 2024, nuclear units, including Wolf Creek, became eligible for a production tax credit through 2032. The credit is for $15.00 per MWh and is subject to a phase-out when gross receipts from the facility are between $25.00 per MWh and $43.75 per MWh. The credit may be used to offset Evergy's income tax liability or be transferred to an unrelated third party. The Evergy Companies have estimated the credit based on the existing Internal Revenue Service (IRS) regulations. The IRS may provide guidance regarding the type of revenue to be included in the computation of gross receipts in 2026 which may significantly reduce the amount of nuclear production tax credits available to Evergy. The Evergy Companies have recorded a regulatory liability for these tax credits as the benefits are expected to be refunded to customers as a reduction to revenue in future regulatory proceedings.

The year of origin of Evergy's, Evergy Kansas Central's and Evergy Metro's related tax benefit amounts for federal tax credit carryforwards as of December 31, 2025, are detailed in the following table.

Year of Origin	Amount of Benefit		
	Evergy	Evergy Kansas Central	Evergy Metro
	(millions)		
2007	$ 0.1	$ —	$ —
2019	28.5	25.1	3.3
2020	35.9	28.5	7.3
2021	31.9	28.1	3.6
2022	34.6	31.7	2.6
2023	49.8	45.3	4.3
2024	196.6	125.7	70.8
2025	190.5	123.1	67.2
	$ 567.9	$ 407.5	$ 159.1

As of December 31, 2025 and 2024, Evergy and Evergy Kansas Central had $4.9 million of tax benefits related to state income tax credit carryforwards. The state income tax credits relate primarily to the Kansas high performance incentive program and expire in the years 2038 to 2039. Due to the elimination of the Kansas corporate income tax for utilities, Evergy and Evergy Kansas Central expect a portion of these state tax credit carryforwards to expire unutilized and have provided a valuation allowance against $2.7 million of the state tax benefits.

Net Operating Loss (NOL) Carryforwards

As of December 31, 2025 and 2024, Evergy had deferred tax benefits of $4.6 million and $4.4 million related to state NOLs, respectively. The state NOL carryforwards expire in years 2026 to 2045. Evergy does not expect to utilize $4.5 million of NOLs before the expiration date of the carryforwards of NOLs in certain states. Therefore, a valuation allowance has been provided against $4.5 million of state tax benefits.

Valuation Allowances

Evergy is required to assess the ultimate realization of deferred tax assets using a "more likely than not" assessment threshold. This assessment takes into consideration tax planning strategies within Evergy's control. As a result of this assessment, Evergy has established a partial valuation allowance for state tax NOL carryforwards and tax credit carryforwards. During 2025, $0.3 million of tax expense was recorded in continuing operations primarily related to state NOLs that expired. The tax expense was offset by the reduction in related deferred tax assets.

Uncertain Tax Positions

Evergy is considered open to U.S. federal examination for years after 2009 due to the carryforward of NOLs and general business income tax credits. With few exceptions, Evergy is no longer subject to state and local tax examinations by tax authorities for years before 2021. As of December 31, 2025, Evergy is currently under IRS audit for the 2023 tax year.

21. LEASES

The Evergy Companies lease office buildings, computer equipment, vehicles, generating plant and other property and equipment, including rail cars to serve jointly-owned generating units where Evergy Kansas Central or Evergy Metro is the managing partner and is reimbursed by other joint-owners for the other owners' proportionate share of the costs. Under GAAP, a contract is or contains a lease if the contract conveys the right to control the use of identified property, plant or equipment for a period of time in exchange for consideration. The Evergy Companies assess a contract as being or containing a lease if the contract identifies property, plant and equipment, provides the lessee the right to obtain substantially all of the economic benefits from use of the property, plant and equipment and provides the lessee the right to direct the use of the property, plant and equipment.

The Evergy Companies have entered into several agreements to purchase energy through renewable purchase power agreements that are accounted for as leases that commenced prior to the application of *Topic 842-Leases*. Due to the intermittent nature of renewable generation, these leases have significant variable lease payments not included in the initial and subsequent measurement of the lease liability. Variable lease payments are expensed as incurred. In addition, certain other contracts contain payment for activity that transfers a separate good or service such as utilities or common area maintenance. The Evergy Companies have elected a practical expedient permitted by GAAP to not separate such components of the lease from other lease components for all leases.

The Evergy, Evergy Kansas Central and Evergy Metro leases have remaining terms ranging from 1 to 35 years, 1 to 13 years and 1 to 8 years, respectively. Leases that have original lease terms of twelve months or less are not recognized on the Evergy Companies' balance sheets. Some leases have options to renew the lease or terminate early at the election of the Evergy Companies. Judgment is applied at lease commencement to determine the reasonably certain lease term based on then-current assumptions about use of the leased asset, market conditions and terms in the contract. The judgment applied to determine the lease term can significantly impact the measurement of the lease liability and right-of-use asset and lease classification.

The Evergy Companies typically discount lease payments over the term of the lease using their incremental borrowing rates at lease commencement to measure its initial and subsequent lease liability. For leases that existed at the initial application of Topic 842, the Evergy Companies used the incremental borrowing rates that corresponded to the remaining lease term as of January 1, 2019.

Leases may be classified as either operating leases or finance leases. The lease classification is based on assumptions of the lease term and discount rate, as discussed above, and the fair market value and economic life of the leased asset. Operating leases recognize a consistent expense each period over the lease term, while finance leases will result in the separate presentation of interest expense on the lease liability and amortization of the right-of-use asset. Finance leases are treated as operating leases for rate-making purposes and as such, the Evergy Companies defer to a regulatory asset or liability any material differences between expense recognition and the timing of payments in order to match what is being recovered in customer rates.

The Evergy Companies' lease expense is detailed in the following tables.

Evergy	**2025**	**2024**	**2023**
Finance lease costs		(millions)	
Amortization of right-of-use assets	$ 17.6	$ 11.1	$ 6.1
Interest on lease liabilities	2.7	2.5	2.3
Operating lease costs	23.2	24.0	20.5
Short-term lease costs	4.7	3.5	4.0
Variable lease costs for renewable purchase power agreements	196.6	210.3	266.5
Total lease costs	$ 244.8	$ 251.4	$ 299.4

Evergy Kansas Central	**2025**	**2024**	**2023**
Finance lease costs		(millions)	
Amortization of right-of-use assets	$ 11.7	$ 8.3	$ 5.5
Interest on lease liabilities	2.3	2.2	2.2
Operating lease costs	11.3	12.3	10.0
Short-term lease costs	1.5	1.2	1.5
Variable lease costs for renewable purchase power agreements	62.8	71.0	122.6
Total lease costs	$ 89.6	$ 95.0	$ 141.8

Evergy Metro	2025	2024	2023
Finance lease costs		(millions)	
Amortization of right-of-use assets	$ 4.5	$ 2.3	$ 0.5
Interest on lease liabilities	0.3	0.2	0.1
Operating lease costs	9.9	9.5	8.6
Short-term lease costs	2.5	1.9	2.2
Variable lease costs for renewable purchase power agreements	101.4	103.9	107.5
Total lease costs	$ 118.6	$ 117.8	$ 118.9

Supplemental cash flow information related to the Evergy Companies' leases is detailed in the following tables.

Evergy	2025	2024	2023
Cash paid for amounts included in the measurement of lease liabilities:		(millions)	
Operating cash flows from operating leases	$ 23.1	$ 24.9	$ 20.1
Operating cash flows from finance leases	2.7	2.5	2.3
Financing cash flows from finance leases	17.7	11.7	6.6
Right-of-use assets obtained in exchange for new finance lease liabilities	56.7	17.0	11.9
Right-of-use assets obtained in exchange for new operating lease liabilities	21.7	7.2	20.1

Evergy Kansas Central	2025	2024	2023
Cash paid for amounts included in the measurement of lease liabilities:		(millions)	
Operating cash flows from operating leases	$ 11.4	$ 12.3	$ 9.9
Operating cash flows from finance leases	2.3	2.2	2.1
Financing cash flows from finance leases	11.8	8.7	5.7
Right-of-use assets obtained in exchange for new finance lease liabilities	16.6	13.2	10.2
Right-of-use assets obtained in exchange for new operating lease liabilities	11.0	5.2	9.2

Evergy Metro	2025	2024	2023
Cash paid for amounts included in the measurement of lease liabilities:		(millions)	
Operating cash flows from operating leases	$ 11.3	$ 11.7	$ 9.7
Operating cash flows from finance leases	0.3	0.2	0.1
Financing cash flows from finance leases	4.6	2.5	0.8
Right-of-use assets obtained in exchange for new finance lease liabilities	12.7	2.6	1.7
Right-of-use assets obtained in exchange for new operating lease liabilities	8.8	1.9	9.9

Other pertinent information related to the Evergy Companies' leases is detailed in the following tables.

Evergy	2025	2024
	(dollars in millions)	
Right-of-use assets under finance leases included in property, plant and equipment, net, on the consolidated balance sheets	$ 399.0	$ 356.9
Right-of-use assets under operating leases included in other assets on the consolidated balance sheets	62.0	58.3
Weighted-average remaining lease term (years)		
Finance leases	10.8	8.3
Operating leases	4.7	5.4
Weighted average discount rate		
Finance leases	5.3 %	5.3 %
Operating leases	4.8 %	4.4 %

Evergy Kansas Central	2025	2024
	(dollars in millions)	
Right-of-use assets under finance leases included in property, plant and equipment, net, on the consolidated balance sheets	$ 89.0	$ 84.5
Right-of-use assets under operating leases included in other assets on the consolidated balance sheets	20.7	17.4
Weighted-average remaining lease term (years)		
Finance leases	8.2	9.1
Operating leases	3.2	2.7
Weighted average discount rate		
Finance leases	5.3 %	5.3 %
Operating leases	4.4 %	3.8 %

Evergy Metro	2025	2024
	(dollars in millions)	
Right-of-use assets under finance leases included in property, plant and equipment, net, on the consolidated balance sheets	$ 23.9	$ 13.0
Right-of-use assets under operating leases included in other assets on the consolidated balance sheets	30.3	29.3
Weighted-average remaining lease term (years)		
Finance leases	4.9	5.3
Operating leases	5.6	6.6
Weighted average discount rate		
Finance leases	5.0 %	5.2 %
Operating leases	5.0 %	5.0 %

Finance Leases

Right-of-use assets for finance leases are included in property, plant and equipment on the Evergy Companies' balance sheets. Lease liabilities for finance leases are included in other current and other long-term liabilities. Payments and other supplemental information for finance leases as of December 31, 2025, are detailed in the following table.

	Evergy	Evergy Kansas Central	Evergy Metro
		(millions)	
2026	$ 22.8	$ 14.5	$ 5.4
2027	22.0	13.6	5.2
2028	21.0	13.0	4.9
2029	17.1	10.6	3.8
2030	12.7	8.0	2.4
After 2030	78.1	32.7	2.5
Total finance lease payments	173.7	92.4	24.2
Amounts representing imputed interest	(43.7)	(18.3)	(0.3)
Present value of lease payments	130.0	74.1	23.9
Less: current portion	(18.3)	(11.9)	(5.0)
Total long-term obligations under finance leases	$ 111.7	$ 62.2	$ 18.9

Operating Leases

Right-of-use assets for operating leases are included in other long-term assets on the Evergy Companies' balance sheets. Lease liabilities for operating leases are included in other current and other long-term liabilities. Lease payments and other supplemental information for operating leases as of December 31, 2025, are detailed in the following table.

	Evergy	Evergy Kansas Central	Evergy Metro
		(millions)	
2026	$ 18.9	$ 8.1	$ 10.3
2027	15.0	6.0	8.4
2028	11.8	4.1	7.2
2029	8.0	2.0	5.7
2030	6.6	1.3	5.1
After 2030	8.6	0.1	8.4
Total operating lease payments	68.9	21.6	45.1
Amounts representing imputed interest	(7.9)	(1.2)	(6.3)
Present value of lease payments	61.0	20.4	38.8
Less: current portion	(16.4)	(7.3)	(8.6)
Total long-term obligations under operating leases	$ 44.6	$ 13.1	$ 30.2

22. SEGMENT INFORMATION

Evergy's chief operating decision maker is Evergy's President and Chief Executive Officer. The chief operating decision maker assesses Evergy's performance based on consolidated net income attributable to Evergy, Inc. (i.e., Evergy operates in a single reportable segment) and uses consolidated net income attributable to Evergy, Inc. to make resource allocation decisions and to compare actual results to budget. The measures of segment assets and expenditures for additions to long-lived assets are reported as total assets on the consolidated balance sheet and additions to property, plant and equipment on the consolidated statement of cash flows, respectively. See Note 1 for additional information regarding the operations of Evergy. This segment information is detailed in the following table.

	2025	2024	2023
		(millions)	
OPERATING REVENUES	$ 5,961.6	$ 5,847.3	$ 5,508.2
Less:			
Fuel and purchased power	1,412.4	1,479.9	1,494.8
SPP network transmission costs	438.0	370.9	302.6
Operating and maintenance:			
Operations and customer[(a)]	612.2	611.4	590.7
Support[(a)]	155.4	148.5	137.6
Other segment items, including benefit costs[(b)]	227.7	202.0	217.0
Depreciation and amortization	1,162.9	1,114.0	1,076.5
Taxes other than income tax	420.1	452.6	406.6
Interest expense	616.3	563.1	525.8
Income tax expense	29.9	30.0	15.6
Net income attributable to noncontrolling interests	12.3	12.3	12.3
Plus:			
Total other income (expense), net	(25.6)	3.1	(4.8)
Equity in earnings of equity method investees, net of income taxes	6.8	7.8	7.4
NET INCOME ATTRIBUTABLE TO EVERGY, INC.	$ 855.6	$ 873.5	$ 731.3

[(a)] In 2025, an internal reorganization that altered departmental hierarchies resulted in changes to the classification of certain operation and maintenance expenses. Amounts for 2024 and 2023 have been recast to conform to the current-year presentation and these reclassifications have no impact on total operation and maintenance expense or net income attributable to Evergy, Inc.

[(b)] Other segment items include benefits expense associated with Operations, Customer and Support employees, regulatory amortization expense, expense associated with energy efficiency programs and credit loss expense, among other items.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

EVERGY

Disclosure Controls and Procedures

Evergy maintains a set of disclosure controls and procedures designed to provide reasonable assurance that information required to be disclosed by the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. In addition, the disclosure controls and procedures provide reasonable assurance that information required to be disclosed is accumulated and communicated to management, including to the chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure. Evergy carried out an evaluation of its disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). This evaluation was conducted under the supervision, and with the participation, of Evergy's management, including the chief executive officer and chief financial officer, and

Evergy's disclosure committee. Based upon this evaluation, the chief executive officer and chief financial officer of Evergy have concluded as of the end of the period covered by this report that the disclosure controls and procedures of Evergy were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting
There has been no change in Evergy's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) that occurred during the quarterly period ended December 31, 2025, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting
Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) for Evergy. Under the supervision and with the participation of Evergy's chief executive officer and chief financial officer, management evaluated the effectiveness of Evergy's internal control over financial reporting as of December 31, 2025. Management used for this evaluation the framework in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has concluded that, as of December 31, 2025, Evergy's internal control over financial reporting is effective based on the criteria set forth in the COSO framework. Deloitte & Touche LLP, the independent registered public accounting firm that audited the financial statements included in this annual report on Form 10-K, has issued its attestation report on Evergy's internal control over financial reporting, which is included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Evergy, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Evergy, Inc. and subsidiaries (the "Company") 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 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 COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2025, of the Company and our report dated February 18, 2026, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

/s/ DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 18, 2026

EVERGY KANSAS CENTRAL

Disclosure Controls and Procedures

Evergy Kansas Central maintains a set of disclosure controls and procedures designed to provide reasonable assurance that information required to be disclosed by the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. In addition, the disclosure controls and procedures provide reasonable assurance that information required to be disclosed is accumulated and communicated to management, including to the chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure. Evergy Kansas Central carried out an evaluation of its disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). This evaluation was conducted under the supervision, and with the participation, of Evergy Kansas Central's management, including the chief executive officer and chief financial officer, and Evergy Kansas Central's disclosure committee. Based upon this evaluation, the chief executive officer and chief financial officer of Evergy Kansas Central have concluded as of the end of the period covered by this report that the disclosure controls and procedures of Evergy Kansas Central were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There has been no change in Evergy Kansas Central's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) that occurred during the quarterly period ended December 31, 2025, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) for Evergy Kansas Central. Under the supervision and with the participation of Evergy Kansas Central's chief executive officer and chief financial officer, management evaluated the effectiveness of Evergy Kansas Central's internal control over financial reporting as of December 31, 2025. Management used for this evaluation the framework in *Internal Control - Integrated Framework (2013)* issued by the COSO of the Treadway Commission.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has concluded that, as of December 31, 2025, Evergy Kansas Central's internal control over financial reporting is effective based on the criteria set forth in the COSO framework.

EVERGY METRO

Disclosure Controls and Procedures

Evergy Metro maintains a set of disclosure controls and procedures designed to provide reasonable assurance that information required to be disclosed by the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. In addition, the disclosure controls and procedures provide reasonable assurance that information required to be disclosed is accumulated and communicated to management, including to the chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure. Evergy Metro carried out an evaluation of its disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). This evaluation was conducted under the supervision, and with the participation, of Evergy Metro's management, including the chief executive officer and chief financial officer, and Evergy Metro's disclosure committee. Based upon this evaluation, the chief executive officer and chief financial officer of Evergy Metro have concluded as of the end of the period covered by this report that the disclosure controls and procedures of Evergy Metro were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting
There has been no change in Evergy Metro's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) that occurred during the quarterly period ended December 31, 2025, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting
Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) for Evergy Metro. Under the supervision and with the participation of Evergy Metro's chief executive officer and chief financial officer, management evaluated the effectiveness of Evergy Metro's internal control over financial reporting as of December 31, 2025. Management used for this evaluation the framework in *Internal Control - Integrated Framework (2013)* issued by the COSO of the Treadway Commission.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has concluded that, as of December 31, 2025, Evergy Metro's internal control over financial reporting is effective based on the criteria set forth in the COSO framework.

ITEM 9B. OTHER INFORMATION

Investors should note that the Evergy Companies announce material financial information in SEC filings, press releases and public conference calls. In accordance with SEC guidelines, the Evergy Companies also use the Investor Relations tab on their website, http://investors.evergy.com, to communicate with investors. It is possible that the financial and other information posted there could be deemed to be material information. The information on Evergy's website is not part of this document.

Securities Trading Plans of Directors and Executive Officers
For the three months ended December 31, 2025, no director or officer has adopted, terminated or modified a Rule 10b5-1 plan or non-rule 10b5-1 trading arrangement required to be disclosed under Item 408(a) of Regulation S-K.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

Information required by Items 10-14 of Part III of this Form 10-K with respect to Evergy will be included in an amendment to this Form 10-K, or incorporated by reference to Evergy's definitive proxy statement with respect to its 2026 Annual Meeting of Shareholders (Proxy Statement) on or before April 30, 2026.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Evergy
The information required by this item will be included in an amendment to this Form 10-K or will be incorporated by reference from the following sections of the Proxy Statement:

- Information regarding the directors of Evergy will be contained in the Proxy Statement section titled "Proposal I: Election of Directors."

- If applicable, information regarding compliance with Section 16(a) of the Exchange Act will be contained in the Proxy Statement section titled "Security Ownership of Directors, Management and Beneficial Owners."
- Information regarding the Audit Committee of Evergy will be contained in the Proxy Statement section titled "Corporate Governance Matters - Board Structure - Audit Committee."
- Information regarding Evergy's Code of Ethics will be contained in the Proxy Statement section titled "Corporate Governance Matters - Corporate Governance Practices - Code of Ethics."

Information required by this item regarding Evergy's executive officers is contained in this report in Part I, Item 1 in "Information About Evergy's Executive Officers."

Evergy and its subsidiaries have adopted a Securities Trading Policy which governs transactions in Evergy's and its subsidiaries' securities by directors, officers, employees and others as defined in the Securities Trading Policy. The Securities Trading Policy does not address transactions in Evergy's and its subsidiaries' securities by Evergy or its subsidiaries themselves; however, pursuant to the Code of Ethics, which, among other items, requires Evergy and its subsidiaries to comply with all laws and regulations, it is the policy of Evergy and its subsidiaries to comply with applicable securities laws and regulations with respect to any such transactions. A copy of the Securities Trading Policy is filed as Exhibit 19.1 to this Annual Report on Form 10-K.

Evergy Kansas Central and Evergy Metro
Other information required by this item regarding Evergy Kansas Central and Evergy Metro has been omitted in reliance on General Instruction (I) to Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

Evergy
The information required by this item will be included in an amendment to this Form 10-K or will be incorporated by reference to the following sections of the Proxy Statement: "Proxy Statement Summary and Highlights - Executive Compensation Highlights," "Director Compensation," "Executive Summary of Compensation Matters," "Compensation Discussion and Analysis," "Compensation Committee Report," "Executive Compensation Tables," "Director Independence" and "Other Matters - Compensation Committee Interlocks and Insider Participation."

Evergy Kansas Central and Evergy Metro
Other information required by this item regarding Evergy Kansas Central and Evergy Metro has been omitted in reliance on General Instruction (I) to Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Evergy
The information required by this item regarding security ownership of the directors and executive officers of Evergy will be included in an amendment to this Form 10-K or will be incorporated by reference to the "Security Ownership of Directors, Management and Beneficial Owners" section of the Proxy Statement.

Evergy Kansas Central and Evergy Metro
The information required by this item regarding Evergy Kansas Central and Evergy Metro has been omitted in reliance on General Instruction (I) to Form 10-K.

Equity Compensation Plans
The Evergy Long-Term Incentive Plan permits the grant of restricted stock, restricted stock units, bonus shares, stock options, stock appreciation rights, director shares, director deferred share units, performance shares and other stock-based awards to directors, officers and other employees of Evergy.

The following table provides information, as of December 31, 2025, regarding the number of common shares to be issued upon exercise of outstanding options, warrants and rights, their weighted average exercise price, and the number of shares of common stock remaining available for future issuance. The table excludes shares issued or issuable under any defined contribution savings plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders [3]			
Evergy Long-Term Incentive Plan	1,171,916 (1)	$ — (2)	5,660,460
Equity compensation plans not approved by security holders	—	—	—
Total	1,171,916 (1)	$ — (2)	5,660,460

[1] Includes 360,016 RSUs with time-based requirements, 627,821 RSUs with performance measures at target performance levels and director deferred share units for 184,079 shares of Evergy common stock outstanding at December 31, 2025.
[2] The RSUs, RSAs and director deferred share units have no exercise price and therefore are not reflected in the weighted-average exercise price.
[3] As of December 31, 2025, there were approximately 149,642 units outstanding that were deferred pursuant to the Evergy Kansas Central, Inc. non-employee deferred compensation program. Deferred units will continue to receive deferred dividend equivalents in the form of additional deferred units until payouts pursuant to elections begin.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Evergy
The information required by this item will be included in an amendment to this Form 10-K or will be incorporated by reference to the "Director Independence" and "Other Matters - Related Party Transactions" sections of the Proxy Statement.

Evergy Kansas Central and Evergy Metro
The information required by this item regarding Evergy Kansas Central and Evergy Metro has been omitted in reliance on General Instruction (I) to Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Evergy
The information required by this item regarding the independent auditors of Evergy and its subsidiaries will be included in an amendment to this Form 10-K or will be incorporated by reference to the "Ratification of Appointment of Deloitte & Touche LLP" (PCAOB ID No. 34) section of the Proxy Statement.

Evergy Kansas Central and Evergy Metro

The Audit Committee of the Evergy Board functions as the Audit Committee of Evergy Kansas Central and Evergy Metro. The following tables set forth the aggregate fees billed, or expected to be billed, by Deloitte & Touche LLP for audit services rendered in connection with the consolidated financial statements and reports for 2025 and 2024 and for other services rendered during 2025 and 2024 on behalf of Evergy Kansas Central and Evergy Metro, as well as all out-of-pocket costs incurred in connection with these services:

Evergy Kansas Central		2025		2024
Fee Category				
Audit Fees	$	2,263,457	$	1,891,984
Audit-Related Fees		28,333		27,000
Tax Fees		14,541		16,380
All Other Fees		—		—
Total Fees	$	2,306,331	$	1,935,364

Evergy Metro		2025		2024
Fee Category				
Audit Fees	$	1,550,558	$	1,393,290
Audit-Related Fees		28,333		27,000
Tax Fees		9,117		11,171
All Other Fees		—		—
Total Fees	$	1,588,008	$	1,431,461

Audit Fees: Consists of fees billed, or expected to be billed, for professional services rendered for the audits of the annual consolidated financial statements of Evergy Kansas Central and Evergy Metro and reviews of the interim consolidated financial statements included in quarterly reports. Audit fees also include: services provided by Deloitte & Touche LLP in connection with statutory and regulatory filings or engagements; audit reports on audits of the effectiveness of internal control over financial reporting and other attest services, except those not required by statute or regulation; services related to filings with the SEC, including comfort letters, consents and assistance with and review of documents filed with the SEC; and accounting research in support of the audit.

Audit-Related Fees: Consists of fees billed for assurance and related services that are reasonably related to the performance of the audit or review of consolidated financial statements of Evergy Kansas Central and Evergy Metro and are not reported under "Audit Fees." These services include consultation concerning financial accounting and reporting standards.

Tax Fees: Consists of fees billed for tax compliance and related support of tax returns and other tax services, including assistance with tax research and planning.

All Other Fees: Consists of fees for all other services other than those described above.

Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services

The Audit Committee has adopted policies and procedures for the pre-approval of all audit services, audit-related services, tax services and other services to be provided by the independent registered public accounting firm for Evergy Kansas Central and Evergy Metro. Under these policies and procedures, the Audit Committee may pre-approve certain types of services, up to the aggregate fee levels it sets. Any proposed service within a pre-approved type of service that would cause the applicable fee level to be exceeded cannot be provided unless the Audit Committee either amends the applicable fee level or specifically approves the proposed service. The Audit Committee, as well, may specifically approve audit, audit-related, tax or other services on a case-by-case basis. Pre-approval is generally provided for up to one year, unless the Audit Committee specifically provides for a different period. Management provides quarterly updates to the Audit Committee regarding actual fees spent with respect to

pre-approved services. The Chair of the Audit Committee may pre-approve audit, audit-related, tax and other services provided by the independent registered public accounting firm as required between meetings and report such pre-approval at the next Audit Committee meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Financial Statements

Evergy, Inc.		**Page No.**
a.	Consolidated Statements of Comprehensive Income for the years ended December 31, 2025, 2024 and 2023	73
b.	Consolidated Balance Sheets - December 31, 2025 and 2024	74
c.	Consolidated Statements of Cash Flows for the years ended December 31, 2025, 2024 and 2023	76
d.	Consolidated Statements of Changes in Equity for the years ended December 31, 2025, 2024 and 2023	77
e.	Notes to Consolidated Financial Statements	88
f.	Report of Independent Registered Public Accounting Firm	67
Evergy Kansas Central, Inc.		
g.	Consolidated Statements of Income for the years ended December 31, 2025, 2024 and 2023	78
h.	Consolidated Balance Sheets - December 31, 2025 and 2024	79
i.	Consolidated Statements of Cash Flows for the years ended December 31, 2025, 2024 and 2023	81
j.	Consolidated Statements of Changes in Equity for the years ended December 31, 2025, 2024 and 2023	82
k.	Notes to Consolidated Financial Statements	88
l.	Report of Independent Registered Public Accounting Firm	69
Evergy Metro, Inc.		
m.	Consolidated Statements of Comprehensive Income for the years ended December 31, 2025, 2024 and 2023	83
n.	Consolidated Balance Sheets - December 31, 2025 and 2024	84
o.	Consolidated Statements of Cash Flows for the years ended December 31, 2025, 2024 and 2023	86
p.	Consolidated Statements of Changes in Equity for the years ended December 31, 2025, 2024 and 2023	87

q.	Notes to Consolidated Financial Statements	88
r.	Report of Independent Registered Public Accounting Firm	71

Financial Statement Schedules

	Evergy, Inc.	
a.	Schedule I - Parent Company Financial Statements	190
b.	Schedule II - Valuation and Qualifying Accounts and Reserves	194
	Evergy Kansas Central, Inc.	
c.	Schedule II - Valuation and Qualifying Accounts and Reserves	194
	Evergy Metro, Inc.	
d.	Schedule II - Valuation and Qualifying Accounts and Reserves	195

Exhibits

Exhibit Number		Description of Document	Registrant
2.1	*	Agreement and Plan of Merger, dated May 29, 2016, by and among Evergy Kansas Central, Inc. (formerly Westar Energy Inc.), Great Plains Energy Incorporated and, from and after its accession thereto, Merger Sub (as defined therein) (Exhibit 2.1 to Great Plains Energy's Form 8-K filed on May 31, 2016).	Evergy Evergy Kansas Central
2.2	*	Amended and Restated Merger Agreement, dated July 9, 2017, by and among Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.), Great Plains Energy Incorporated, Monarch Energy Holding, Inc., King Energy, Inc. and, solely for the purposes set forth therein, GP Star, Inc. (Exhibit 2.1 to Great Plains Energy's Form 8-K filed on July 10, 2017).	Evergy Evergy Kansas Central
3.1	*	Amended and Restated Articles of Incorporation of Evergy, Inc., effective June 4, 2018 (Exhibit 3.1 to Form 8-K filed on June 4, 2018).	Evergy
3.2	*	Amended and Restated By-laws of Evergy, Inc., effective as of December 13, 2023 (Exhibit 3.1 to Evergy's Form 8-K filed on December 13, 2023).	Evergy
3.3	*	Amended and Restated Articles of Consolidation of Evergy Metro, Inc., as amended September 16, 2019 (Exhibit 3.1 to Evergy Metro's Form 10-Q for the quarter ended September 30, 2019).	Evergy Metro
3.4	*	Amended and Restated By-laws of Evergy Metro, Inc., effective February 28, 2020 (Exhibit 3.3 to Evergy Metro's Form 8-K filed on March 2, 2020).	Evergy Metro
3.5	*	Amended and Restated Articles of Incorporation of Evergy Kansas Central, Inc., as amended September 16, 2019 (Exhibit 3.3 to Evergy Kansas Central's Form 10-Q for the quarter ended September 30, 2019).	Evergy Kansas Central
3.6	*	Amended and Restated By-laws of Evergy Kansas Central, Inc., effective February 28, 2020 (Exhibit 3.2 to Evergy Kansas Central's Form 8-K filed on March 2, 2020).	Evergy Kansas Central
4.1	*	Indenture, dated June 1, 2004, between Evergy, Inc. (successor to Great Plains Energy Incorporated) and BNY Midwest Trust Company, as trustee (Exhibit 4.4 to Great Plains Energy's Form 8-A/A filed on June 14, 2004).	Evergy
4.2	*	First Supplemental Indenture, dated June 14, 2004, between Evergy, Inc. (successor to Great Plains Energy Incorporated) and BNY Midwest Trust Company, as trustee (Exhibit 4.5 to Great Plains Energy's Form 8-A/A filed on June 14, 2004).	Evergy
4.3	*	Second Supplemental Indenture, dated September 25, 2007, between Evergy, Inc. (successor to Great Plains Energy Incorporated) and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1 to Great Plains Energy's Form 8-K filed on September 26, 2007).	Evergy

4.4	*	Third Supplemental Indenture, dated August 13, 2010, between Evergy, Inc. (successor to Great Plains Energy Incorporated) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Great Plains Energy's Form 8-K filed on August 13, 2010).	Evergy
4.5	*	Fourth Supplemental Indenture, dated May 19, 2011, between Evergy, Inc. (successor to Great Plains Energy Incorporated) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Great Plains Energy's Form 8-K filed on May 19, 2011).	Evergy
4.6	*	Fifth Supplemental Indenture, dated March 9, 2017, between Evergy, Inc. (successor to Great Plains Energy Incorporated) and The Bank of New York Trust Company, N.A. as trustee (Exhibit 4.1 to Great Plains Energy's Form 8-K filed on March 9, 2017).	Evergy
4.7	*	Sixth Supplemental Indenture, dated June 4, 2018, by and among Great Plains Energy Incorporated, Evergy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy's Form 8-K filed on June 4, 2018).	Evergy
4.8	*	Seventh Supplemental Indenture, dated as of September 9, 2019 between Evergy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy's Form 8-K filed on September 9, 2019).	Evergy
4.9	*	Subordinated Indenture, dated May 18, 2009, between Evergy, Inc. (successor to Great Plains Energy Incorporated) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Great Plains Energy's Form 8-K filed on May 18, 2009).	Evergy
4.10	*	Supplemental Indenture No. 1, dated May 18, 2009, between Evergy, Inc. (successor to Great Plains Energy Incorporated) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.2 to Great Plains Energy's Form 8-K filed on May 19, 2009).	Evergy
4.11	*	Supplemental Indenture No. 2, dated March 22, 2012, between Evergy, Inc. (successor to Great Plains Energy Incorporated) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Great Plains Energy's Form 8-K filed on March 23, 2012).	Evergy
4.12	*	Supplemental Indenture No. 3, dated June 4, 2018, by and among Great Plains Energy Incorporated, Evergy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.2 to Evergy's Form 8-K filed on June 4, 2018).	Evergy
4.13	*	Supplemental Indenture No. 4, dated as of December 5, 2024, by and between Evergy, Inc. (as successor to Great Plains Energy Incorporated) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy's Form 8-K filed on December 5, 2024).	Evergy

4.14	*	Equity Distribution Agreement, dated May 8, 2025, between Evergy, Inc. and each of (a) Barclays Capital Inc., BofA Securities, Inc., Citigroup Global Markets Inc., Goldman Sachs & Co. LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC, MUFG Securities Americas Inc., TD Securities (USA) LLC, Truist Securities, Inc. and Wells Fargo Securities, LLC, acting as managers, (b) Barclays Bank PLC, Bank of America, N.A., Citibank, N.A., Goldman Sachs & Co. LLC, JPMorgan Chase Bank, National Association, Morgan Stanley & Co. LLC, MUFG Securities EMEA plc, The Toronto-Dominion Bank, Truist Bank and Wells Fargo Bank, National Association, acting as forward purchasers, and (c) Barclays Capital Inc., BofA Securities, Inc., Citigroup Global Markets Inc., Goldman Sachs & Co. LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC, MUFG Securities Americas Inc., TD Securities (USA) LLC, Truist Securities, Inc. and Wells Fargo Securities, LLC acting as forward sellers (Exhibit 1.1 to Evergy's Form 8-K filed on May 9, 2025).	Evergy
4.15	*	Indenture, dated August 24, 2001, between Evergy Missouri West, Inc. (formerly Aquila, Inc.) and BankOne Trust Company, N.A., as trustee (Exhibit 4(d) to Registration Statement on Form S-3 (File No. 333-68400) filed by Aquila, Inc. on August 27, 2001).	Evergy
4.16	*	Second Supplemental Indenture, dated July 3, 2002, between Missouri West, Inc. (formerly Aquila, Inc.) and BankOne Trust Company, N.A., as trustee (Exhibit 4(c) to Form S-4 (File No. 333-100204) filed by Aquila, Inc. on September 30, 2002).	Evergy
4.17	*	General Mortgage and Deed of Trust, dated December 1, 1986, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.12 to Evergy Metro's Form 10-K for the year ended December 31, 2017).	Evergy Evergy Metro
4.18	*	Fifth Supplemental Indenture, dated September 1, 1992, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.13 to Evergy Metro's Form 10-K for the year ended December 31, 2017).	Evergy Evergy Metro
4.19	*	Seventh Supplemental Indenture, dated October 1, 1993, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.14 to Evergy Metro's Form 10-K for the year ended December 31, 2017).	Evergy Evergy Metro
4.20	*	Eighth Supplemental Indenture, dated December 1, 1993, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.15 to Evergy Metro's Form 10-K for the year ended December 31, 2017).	Evergy Evergy Metro

4.21	*	Eleventh Supplemental Indenture, dated August 15, 2005, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.2 to Evergy Metro's Form 10-Q for the quarter ended September 30, 2005).	Evergy Evergy Metro
4.22	*	Thirteenth Supplemental Indenture, dated March 1, 2009, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.3 to Evergy Metro's Form 8-K filed on March 24, 2009).	Evergy Evergy Metro
4.23	*	Fourteenth Supplemental Indenture, dated March 1, 2009, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.4 to Evergy Metro's Form 8-K filed on March 24, 2009).	Evergy Evergy Metro
4.24	*	Fifteenth Supplemental Indenture, dated June 30, 2011, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.1 to Evergy Metro's Form 10-Q for the quarter ended June 30, 2011).	Evergy Evergy Metro
4.25	*	Sixteenth Supplemental Indenture, March 1, 2019, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) UMB Bank N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.3 to Evergy's Form 8-K filed on March 14, 2019).	Evergy Evergy Metro
4.26	*	Seventeenth Supplemental Indenture, dated March 27, 2019, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.1 to Evergy's Form 8-K filed on March 27, 2019).	Evergy Evergy Metro
4.27	*	Eighteenth Supplemental Indenture, dated as of May 26, 2020, between Evergy Metro and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.1 to Evergy's Form 8-K filed on May 26, 2020).	Evergy Evergy Metro
4.28	*	Indenture, dated December 1, 2000, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and The Bank of New York, as trustee (Exhibit 4(a) to Evergy Metro's Form 8-K filed on December 18, 2000).	Evergy Evergy Metro
4.29	*	Indenture, dated March 1, 2002, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and The Bank of New York, as trustee (Exhibit 4.1.b. to Evergy Metro's Form 10-Q for the quarter ended March 31, 2002).	Evergy Evergy Metro
4.30	*	Supplemental Indenture No. 1, dated November 15, 2005, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and The Bank of New York, as trustee (Exhibit 4.2.j to Evergy Metro's Form 10-K for the year ended December 31, 2005).	Evergy Evergy Metro

4.31	*	Supplemental Indenture No. 2, dated March 1, 2019, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and The Bank of New York Mellon, as trustee (Exhibit 4.2 to Evergy's Form 8-K filed on March 14, 2019).	Evergy Evergy Metro
4.32	*	Indenture, dated May 1, 2007, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy Metro's Form 8-K filed on June 4, 2007).	Evergy Evergy Metro
4.33	*	Supplemental Indenture No. 1, dated June 4, 2007, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.2 to Evergy Metro's Form 8-K filed on June 4, 2007).	Evergy Evergy Metro
4.34	*	Supplemental Indenture No. 2, dated March 11, 2008, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.2 to Evergy Metro's Form 8-K filed on March 11, 2008).	Evergy Evergy Metro
4.35	*	Supplemental Indenture No. 3, dated September 20, 2011, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and The Bank of New York Mellon Trust Company, N.A., trustee (Exhibit 4.1 to Evergy Metro's Form 8-K filed on September 20, 2011).	Evergy Evergy Metro
4.36	*	Supplemental Indenture No. 4, dated March 14, 2013, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and The Bank of New York Mellon Trust Company, N.A., trustee (Exhibit 4.1 to Evergy Metro's Form 8-K filed on March 14, 2013).	Evergy Evergy Metro
4.37	*	Supplemental Indenture No. 5, dated August 18, 2015, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and The Bank of New York Mellon Trust Company, N.A., trustee (Exhibit 4.1 to Evergy Metro's Form 8-K filed on August 18, 2015).	Evergy Evergy Metro
4.38	*	Supplemental Indenture No. 6, dated June 15, 2017, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy Metro's Form 8-K filed on June 15, 2017).	Evergy Evergy Metro
4.39	*	Supplemental Indenture No. 7, dated March 1, 2018, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy Metro's Form 8-K filed on March 1, 2018).	Evergy Evergy Metro

4.40	*	Supplemental Indenture No. 8, dated March 1, 2019, between Evergy Metro, Inc. (formerly Kansas City Power & Light Company) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy Metro's Form 8-K filed on March 14, 2019).	Evergy Evergy Metro
4.41	*	Note Purchase Agreement, dated August 16, 2013, among Evergy Missouri West, Inc. (formerly KCP&L Greater Missouri Operations Company), Evergy, Inc. and the purchasers party thereto (Exhibit 4.1 to Great Plains Energy's Form 8-K filed on August 19, 2013).	Evergy
4.42	*	Note Purchase Agreement dated February 12, 2019, among Evergy Missouri West, Inc. (formerly KCP&L Greater Missouri Operations Company), Evergy, Inc. and the purchasers party thereto (Exhibit 4.5 to Evergy's Form 10-Q for the quarter ended March 31, 2019).	Evergy
4.43	*	Note Purchase Agreement, dated April 20, 2021, among Evergy Missouri West, Inc. (formerly KCP&L Greater Missouri Operations Company), Evergy, Inc. and the purchasers party thereto (Exhibit 4.1 to Evergy's 8-K filed on April 20, 2021).	Evergy
4.44	*	Mortgage and Deed of Trust, dated July 1, 1939, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc. and The Kansas Power and Light Company) and Harris Trust and Savings Bank, as trustee (Exhibit 4.35 to Evergy Kansas Central's Form 10-K for the fiscal year ended December 31, 2018).	Evergy Evergy Kansas Central
4.45	*	First Supplemental Indenture, dated July 1, 1939, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc. and The Kansas Power and Light Company) and Harris Trust and Savings Bank, as trustee (Exhibit 4.36 to Evergy Kansas Central's Form 10-K for the fiscal year ended December 31, 2018).	Evergy Evergy Kansas Central
4.46	*	Second Supplemental Indenture, dated April 1, 1949, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc. and The Kansas Power and Light Company) and Harris Trust and Savings Bank, as trustee (Exhibit 4.37 to Evergy Kansas Central's Form 10-K for the fiscal year ended December 31, 2018).	Evergy Evergy Kansas Central
4.47	*	Sixth Supplemental Indenture, dated October 4, 1951, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc. and The Kansas Power and Light Company) and Harris Trust and Savings Bank, as trustee (Exhibit 4.38 to Evergy Kansas Central's Form 10-K for the fiscal year ended December 31, 2018).	Evergy Evergy Kansas Central
4.48	*	Fourteenth Supplemental Indenture, dated May 1, 1976, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc. and The Kansas Power and Light Company) and Harris Trust and Savings Bank, as trustee (Exhibit 4.39 to Evergy Kansas Central's Form 10-K for the fiscal year ended December 31, 2018).	Evergy Evergy Kansas Central

4.49	*	Twenty-Eighth Supplemental Indenture, dated July 1, 1992, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc. and Western Resources, Inc.) and Harris Trust and Savings Bank, as trustee (Exhibit 4.40 to Evergy Kansas Central's Form 10-K for the fiscal year ended December 31, 2018).	Evergy Evergy Kansas Central
4.50	*	Thirty-Second Supplemental Indenture, dated April 15, 1994, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc. and Western Resources, Inc.) and Harris Trust and Savings Bank, as trustee (Exhibit 4(s) to Evergy Kansas Central's Form 10-K for the fiscal year ended December 31, 1994).	Evergy Evergy Kansas Central
4.51	*	Thirty-Fourth Supplemental Indenture, dated June 28, 2000, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc. and Western Resources, Inc.) and Harris Trust and Savings Bank, as trustee (Exhibit 4(v) to Evergy Kansas Central's Form 10-K for the fiscal year ended December 31, 2000).	Evergy Evergy Kansas Central
4.52	*	Thirty-Sixth Supplemental Indenture, dated June 1, 2004, between Evergy Kansas Central, Inc. (formerly Westar Energy Inc.) and BNY Midwest Trust Company, as trustee (Exhibit 4.1 to Evergy Kansas Central's Form 8-K filed on January 18, 2005).	Evergy Evergy Kansas Central
4.53	*	Thirty-Eighth Supplemental Indenture, dated January 18, 2005, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) and BNY Midwest Trust Company, as trustee (Exhibit 4.3 to Evergy Kansas Central's Form 8-K filed on January 18, 2005).	Evergy Evergy Kansas Central
4.54	*	Thirty-Ninth Supplemental Indenture, dated June 30, 2005, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) and BNY Midwest Trust Company, as trustee (Exhibit 4.1 to Evergy Kansas Central's Form 8-K filed on July 1, 2005).	Evergy Evergy Kansas Central
4.55	*	Forty-Second Supplemental Indenture, dated March 1, 2012, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy Kansas Central's Form 8-K filed on February 29, 2012).	Evergy Evergy Kansas Central
4.56	*	Forty-Second Supplemental (Reopening) Indenture, dated May 17, 2012, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy Kansas Central's Form 8-K filed on May 16, 2012).	Evergy Evergy Kansas Central
4.57	*	Forty-Third Supplemental Indenture, dated March 28, 2013, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy Kansas Central's Form 8-K filed on March 22, 2013).	Evergy Evergy Kansas Central
4.58	*	Forty-Fourth Supplemental Indenture, dated August 19, 2013, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy Kansas Central's Form 8-K filed on August 14, 2013).	Evergy Evergy Kansas Central

4.59	*	Forty-Fifth Supplemental Indenture, dated November 13, 2015, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy Kansas Central's Form 8-K filed on November 6, 2015).	Evergy Evergy Kansas Central
4.60	*	Forty-Sixth Supplemental Indenture, dated June 20, 2016, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy Kansas Central's Form 8-K filed on June 17, 2016).	Evergy Evergy Kansas Central
4.61	*	Forty-Seventh Supplemental Indenture, dated March 6, 2017, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy Kansas Central's Form 8-K filed on March 3, 2017).	Evergy Evergy Kansas Central
4.62	*	Forty-Eighth Supplemental Indenture, dated June 4, 2018, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy Kansas Central's Form 8-K filed on June 4, 2018).	Evergy Evergy Kansas Central
4.63	*	Forty-Ninth Supplemental Indenture, dated August 19, 2019, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy Kansas Central's Form 8-K filed on August 19, 2019).	Evergy Evergy Kansas Central
4.64	*	Fiftieth Supplemental Indenture, dated as of April 9, 2020, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy Kansas Central's Form 8-K filed on April 9, 2020).	Evergy Evergy Kansas Central
4.65	*	Senior Indenture, dated August 1, 1998, between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) and Deutsche Bank Trust Company Americas, as trustee, including Form of Senior Note (Exhibit 4.1 to Evergy Kansas Central's Form 10-Q for the quarter ended June 30, 1998).	Evergy Evergy Kansas Central
4.66	*	Form of Subordinated Indenture between Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., as trustee, including Form of Subordinated Note (Exhibit 4.3 to Evergy Kansas Central's Form S-3 filed on March 18, 2016 (No. 333-210266)).	Evergy Evergy Kansas Central
4.67	*	Description of Securities (Exhibit 4.64 to Evergy, Inc.'s Form 10-K for the fiscal year ended December 31, 2020).	Evergy Evergy Kansas Central Evergy Metro

4.68	*	First Mortgage Indenture and Deed of Trust, dated as of March 1, 2022, between Evergy Missouri West, Inc. and UMB Bank, N.A., as trustee (Exhibit 4.1 to Evergy's Form 8-K filed on March 7, 2022).	Evergy
4.69	*	First Supplemental Indenture dated as of March 1, 2022, between Evergy Missouri West, Inc. and UMB Bank, N.A., as trustee (Exhibit 4.2 to Evergy's Form 8-K filed on March 7, 2022).	Evergy
4.70	*	Fifty-First Supplemental Indenture, dated as of March 14, 2023, between Evergy Kansas Central, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy's Form 8-K filed on March 14, 2023).	Evergy Evergy Kansas Central
4.71	*	Nineteenth Supplemental Indenture, dated as of April 4, 2023, between Evergy Metro and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.1 to Evergy's Form 8-K filed on April 6, 2023).	Evergy Evergy Metro
4.72	*	Fifty-Second Supplemental Indenture, dated as of November 15, 2023, between Evergy Kansas Central, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy's Form 8-K filed on November 15, 2023).	Evergy Evergy Kansas Central
4.73	*	Indenture, dated as of December 7, 2023 by and between Evergy, Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee, and form of global note included therein (Exhibit 4.1 to Evergy's Form 8-K filed on December 7, 2023).	Evergy
4.74	*	Twentieth Supplemental Indenture, dated as of December 1, 2023, between Evergy Metro, Inc. and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.3.13 to Evergy Metro's Form S-3 filed on August 16, 2024 (No. 333-281614-01).	Evergy Evergy Metro
4.75	*	Twenty-First Supplemental Indenture, dated as of April 5, 2024, by and between Evergy Metro and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.1 to Evergy's Form 8-K filed on April 5, 2024).	Evergy Evergy Metro
4.76	*	Supplemental Indenture No. 4, dated as of December 5, 2024, by and among Great Plains Energy Incorporated, Evergy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy's Form 8-K filed on December 5, 2024.	Evergy
4.77	*	Fifty-Third Supplemental Indenture, dated as of March 13, 2025, between Evergy Kansas Central, Inc. and The Bank of New York Mellon Trust company, N.A., as trustee (Exhibit 4.1 to Evergy's Form 8-K filed on March 13, 2025).	Evergy Evergy Kansas Central
4.78	*	First Supplemental Indenture, dated as of March 13, 2025, between Evergy Kansas Central, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (as Successor to Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company)) (Exhibit 4.2 to Evergy's Form 8-K filed on March 13, 2025).	Evergy Evergy Kansas Central

4.79	*	Twenty-second Supplemental Indenture, dated as of August 15, 2025, between Evergy Metro and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.1 to Evergy's Form 8-K filed on August 15, 2025).	Evergy Evergy Metro
4.80	*	Fifty-Fourth Supplemental Indenture, dated as of November 25, 2025, between Evergy Kansas Central, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Evergy's Form 8-K filed on November 25, 2025).	Evergy Evergy Kansas Central
4.81	*	Fifty-Third Supplemental (Reopening) Indenture, dated as of December 5, 2025, between Evergy Kansas Central, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.2 to Evergy's Form 8-K filed on December 5, 2025).	Evergy Evergy Kansas Central
10.1	*+	Evergy, Inc. (successor to Great Plains Energy Incorporated) Amended Long-Term Incentive Plan, as amended effective on May 3, 2016 (Exhibit 10.4 to Great Plains Energy's Form 10-Q for the quarter ended June 30, 2016).	Evergy Evergy Metro
10.2	*+	Evergy, Inc. Long-Term Incentive Plan (formerly the Great Plains Energy Incorporated Long-Term Incentive Plan, as amended), effective June 4, 2018 (Exhibit 99.1 to Evergy's Registration Statement on Form S-8 filed on June 15, 2018 (File No. 333-225673)).	Evergy Evergy Metro Evergy Kansas Central
10.3	*+	Form of Evergy, Inc. 2023 Performance-Based Restricted Stock Unit Agreement (Exhibit 10.9 to Evergy's Form 10-K for the fiscal year ended December 31, 2022).	Evergy Evergy Metro Evergy Kansas Central
10.4	*+	Form of Evergy, Inc. 2023 Time-Based Restricted Stock Unit Agreement (Exhibit 10.10 to Evergy's Form 10-K for the fiscal year ended December 31, 2022).	Evergy Evergy Metro Evergy Kansas Central
10.5	*+	Evergy, Inc. Long-Term Incentive Plan, as Amended and Restated, on May 3, 2022 (Appendix C to Evergy, Inc.'s Definitive Proxy Statement on Schedule 14A filed on March 23, 2022).	Evergy Evergy Metro Evergy Kansas Central
10.6	*+	Form of Evergy, Inc. 2024 Time-Based Restricted Stock Unit Agreement (Cliff Vesting) (Exhibit 10.11 to Evergy's Form 10-K for the fiscal year ended December 31, 2023).	Evergy Evergy Metro Evergy Kansas Central
10.7	*+	Form of Evergy, Inc. 2024 Time-Based Restricted Stock Unit Agreement (Tranche Vesting) (Exhibit 10.12 to Evergy's Form 10-K for the fiscal year ended December 31, 2023).	Evergy Evergy Metro Evergy Kansas Central
10.8	*+	Form of Evergy, Inc. 2024 Performance-Based Restricted Stock Unit Agreement (Exhibit 10.13 to Evergy's Form 10-K for the fiscal year ended December 31, 2023).	Evergy Evergy Metro Evergy Kansas Central
10.9	*+	Form of Evergy, Inc. 2025 Time-Based Restricted Stock Unit Agreement (Cliff Vesting) (Exhibit 10.15 to Evergy's Form 10-K for the fiscal year ended December 31, 2024).	Evergy Evergy Metro Evergy Kansas Central

10.10	*+	Form of Evergy, Inc. 2025 Time-Based Restricted Stock Unit Agreement (Tranche Vesting) (Exhibit 10.16 to Evergy's Form 10-K for the fiscal year ended December 31, 2024).	Evergy Evergy Metro Evergy Kansas Central
10.11	*+	Form of Evergy, Inc. 2025 Performance-Based Restricted Stock Unit Agreement (Exhibit 10.17 to Evergy's Form 10-K for the fiscal year ended December 31, 2024).	Evergy Evergy Metro Evergy Kansas Central
10.12	*+	Evergy, Inc. 2025 Annual Incentive Plan (Exhibit 10.18 to Evergy's Form 10-K for the fiscal year ended December 31, 2024).	Evergy Evergy Metro Evergy Kansas Central
10.13	+	Form of Evergy, Inc. 2026 Time-Based Restricted Stock Unit Award Agreement	Evergy Evergy Metro Evergy Kansas Central
10.14	+	Form of Evergy, Inc. 2026 Time-Based Restricted Stock Unit Award Agreement (Alternate)	Evergy Evergy Metro Evergy Kansas Central
10.15	+	Form of Evergy, Inc. 2026 Performance-Based Restricted Stock Unit Award Agreement	Evergy Evergy Metro Evergy Kansas Central
10.16	+	Form of Evergy, Inc. 2026 Performance-Based Restricted Stock Unit Award Agreement (Alternate)	Evergy Evergy Metro Evergy Kansas Central
10.17	+	Evergy, Inc. 2026 Annual Incentive Plan	Evergy Evergy Metro Evergy Kansas Central
10.18	*+	David A. Campbell Offer Letter, dated December 3, 2020 (Exhibit 10.1 to Evergy's Form 8-K filed on December 8, 2020).	Evergy Evergy Metro Evergy Kansas Central
10.19	*+	Form of Time-Based Restricted Stock Award Agreement for David A. Campbell (Exhibit 10.3 to Evergy's Form 8-K/A filed on December 22, 2020).	Evergy Evergy Metro Evergy Kansas Central
10.20	*+	W. Bryan Buckler Offer Letter, dated August 18, 2024 (Exhibit 10.1 to Evergy's Form 8-K filed on August 26, 2024).	Evergy Evergy Metro Evergy Kansas Central
10.21	*+	Form of Indemnification Agreement with Evergy, Inc. officers and directors (Exhibit 10.2 to Evergy's Form 10-Q for the quarter ended September 30, 2018).	Evergy Evergy Metro Evergy Kansas Central
10.22	*+	Form of Evergy, Inc. Amended and Restated Change-in-Control Severance Agreement (Exhibit 10.20 to Evergy's Form 10-K for the fiscal year ended December 31, 2023).	Evergy Evergy Metro Evergy Kansas Central

10.23	*+	Evergy, Inc. Executive Severance Plan, dated November 6, 2019 (Exhibit 10.1 to Evergy's Form 10-Q for the quarter ended September 30, 2019).	Evergy
10.24	*+	Evergy, Inc. Supplemental Executive Retirement Plan, effective June 4, 2018 (Exhibit 10.6 to Evergy's Form 10-Q for the quarter ended June 30, 2018).	Evergy Evergy Metro Evergy Kansas Central
10.25	*+	Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) Retirement Benefit Restoration Plan (Exhibit 10.1 to Evergy Kansas Central's Form 8-K filed on April 2, 2010).	Evergy Evergy Kansas Central
10.26	*+	Amendment dated December 12, 2018 to Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) Retirement Benefit Restoration Plan (Exhibit 10.35 to Evergy Kansas Central's Form 10-K for the fiscal year ended December 31, 2018).	Evergy Evergy Kansas Central
10.27	*+	Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.) Non-Employee Director Nonqualified Deferred Compensation Plan, as amended and restated May 17, 2018 (Exhibit 10.8 to Evergy Kansas Central's Form 10-Q for the quarter ended June 30, 2018).	Evergy Evergy Kansas Central
10.28	*+	Evergy, Inc. Nonqualified Deferred Compensation Plan, effective June 4, 2018 (Exhibit 10.39 to Evergy's Form 10-K for the fiscal year ended December 31, 2018).	Evergy Evergy Metro Evergy Kansas Central
10.29	*+	Evergy, Inc. Amended and Restated Nonqualified Deferred Compensation Plan, effective January 1, 2023 (Exhibit 10.26 to Evergy's Form 10-K for the fiscal year ended December 31, 2022).	Evergy Evergy Metro Evergy Kansas Central
10.30	+	Summary of Evergy, Inc. Non-Employee Director Compensation	Evergy Evergy Metro Evergy Kansas Central
10.31	*	Amended and Restated Credit Agreement, dated August 31, 2021, by and among Evergy, Inc., Evergy Missouri West, Inc. (formerly KCP&L Greater Missouri Operations Company), Evergy Metro, Inc. (formerly Kansas City Power & Light Company), Evergy Kansas Central, Inc. (formerly Westar Energy, Inc.), as Borrowers, the lenders referred to therein, as Lenders, and Wells Fargo Bank, National Association, as Administrative Agent, Swingline Lender and Issuing Lender, Bank of America, N.A., Citibank, N.A., MUFG Bank, Ltd., TD Bank, N.A. and U.S. Bank National Association as Co-Syndication Agents and Issuing Lenders, Wells Fargo Securities, LLC, as Sustainability Structuring Agent, and Wells Fargo Securities, LLC, Citigroup Global Markets Inc., BOFA Securities, Inc., MUFG Bank, Ltd., TD Securities (USA) LLC and U.S. Bank National Association as Joint Lead Arrangers and Joint Bookrunners. (Exhibit 10.1 to Evergy's Form 8-K filed on August 31, 2021).	Evergy Evergy Metro Evergy Kansas Central

10.32	*	First Amendment to Amended and Restated Credit Agreement, dated as of June 2, 2023, by and among Evergy, Inc., Evergy Metro, Inc., Evergy Missouri West, Inc., and Evergy Kansas Central, Inc., as Borrowers, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (Exhibit 10.1 to Evergy's Form 8-K filed on June 2, 2023).	Evergy Evergy Metro Evergy Kansas Central
10.33	*	Term Loan Credit Agreement dated as of February 25, 2022, by and among Evergy, Inc., Wells Fargo Bank, National Association, as Administrative Agent, and the lenders referred to therein. (Exhibit 10.1 to Evergy's Form 8-K on February 28, 2022).	Evergy
10.34	*	First Amendment to Term Loan Credit Agreement, dated as of February 23, 2023, by and among Evergy, Inc., Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (Exhibit 10.1 to Evergy's Form 8-K filed on February 27, 2023).	Evergy
10.35	*	Second Amendment to Term Loan Credit Agreement, dated as of November 29, 2023, by and among Evergy, Inc. Wells Fargo Bank, National association, as administrative agent, and the lenders party thereto (Exhibit 10.1 to Evergy's Form 8-K filed on December 4, 2023).	Evergy
10.36	*	Term Loan Credit Agreement, dated as of February 11, 2026, between Evergy, Inc. and Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (Exhibit 10.1 to Evergy's Form 8-K filed on February 11, 2026).	Evergy
10.37	*	Guaranty Agreement, dated April 20, 2021, issued by Evergy in favor of the holders of Evergy Missouri West, Inc.'s 2.86% Senior Notes due 2031, 3.01% Senior Notes due 2033 and 3.21% Senior Notes due 2033 (Exhibit 10.1 to Evergy's Current Report on Form 8-K filed on April 20, 2021).	Evergy
10.38	*	Guaranty Agreement, dated April 20, 2021, issued by Evergy, Inc. in favor of the holders of Evergy Missouri West, Inc.'s 3.49% Senior Notes due 2025, 4.06% Senior Notes due 2033 and 4.74% Senior Notes due 2043 (Exhibit 10.2 to Evergy's Form 8-K filed on April 20, 2021).	Evergy
10.39	*	Cooperation Agreement, dated February 25, 2021, by and between Evergy, Inc. and Bluescape Energy Partners, LLC (Exhibit 10.1 to Evergy's Form 8-K filed on February 26, 2021).	Evergy
10.40	*	Securities Purchase Agreement, dated February 25, 2021, by and between Evergy, Inc. and BEP Special Situations V LLC. (Exhibit 10.2 to Evergy's Form 8-K filed on February 26, 2021).	Evergy
10.41	*	Registration Rights Agreement, dated April 14, 2021, by and between Evergy, Inc. and BEP Special Situations V LLC. (Exhibit 10.1 to Evergy's Form 8-K filed on April 14, 2021.	Evergy
19.1	*	Evergy, Inc. and Subsidiaries Securities Trading Policy (Exhibit 19.1 to Evergy, Inc.'s Form 10-K for the fiscal year ended December 31, 2024)	Evergy Evergy Metro Evergy Kansas Central

21.1		List of Subsidiaries.	Evergy Evergy Kansas Central
23.1		Consent of Independent Registered Public Accounting Firm.	Evergy
23.2		Consent of Independent Registered Public Accounting Firm.	Evergy Metro
23.3		Consent of Independent Registered Public Accounting Firm.	Evergy Kansas Central
24.1		Powers of Attorney.	Evergy
24.2		Powers of Attorney.	Evergy Kansas Central
24.3		Powers of Attorney.	Evergy Metro
31.1		Rule 13a-14(a)/15d-14(a) Certification of David A. Campbell.	Evergy
31.2		Rule 13a-14(a)/15d-14(a) Certification of W. Bryan Buckler.	Evergy
31.3		Rule 13a-14(a)/15d-14(a) Certification of David A. Campbell.	Evergy Metro
31.4		Rule 13a-14(a)/15d-14(a) Certification of W. Bryan Buckler.	Evergy Metro
31.5		Rule 13a-14(a)/15d-14(a) Certification of David A. Campbell.	Evergy Kansas Central
31.6		Rule 13a-14(a)/15d-14(a) Certification of W. Bryan Buckler.	Evergy Kansas Central
32.1	**	Section 1350 Certifications.	Evergy
32.2	**	Section 1350 Certifications.	Evergy Metro
32.3	**	Section 1350 Certifications.	Evergy Kansas Central
97	*	Evergy, Inc. Compensation Recoupment (Mandatory Clawback) Policy effective as of October 31, 2023 (Exhibit 97 to Evergy's Form 10-K for the fiscal year ended December 31, 2023).	Evergy
101.INS	***	XBRL Instance Document.	n/a
101.SCH		Inline XBRL Taxonomy Extension Schema Document.	Evergy Evergy Metro Evergy Kansas Central
101.CAL		Inline XBRL Taxonomy Extension Calculation Linkbase Document.	Evergy Evergy Metro Evergy Kansas Central

101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.	Evergy Evergy Metro Evergy Kansas Central
101.LAB	Inline XBRL Taxonomy Extension Labels Linkbase Document.	Evergy Evergy Metro Evergy Kansas Central
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.	Evergy Evergy Metro Evergy Kansas Central
104	Cover Page Interactive Data File (embedded within the Inline XBRL document).	Evergy Evergy Metro Evergy Kansas Central

* Filed with the SEC as exhibits to prior SEC filings and are incorporated herein by reference and made a part hereof. The SEC filings and the exhibit number of the documents so filed, and incorporated herein by reference, are stated in parenthesis in the description of such exhibit.

** Furnished and shall not be deemed filed for the purpose of Section 18 of the Exchange Act. Such document shall not be incorporated by reference into any registration statement or other document pursuant to the Exchange Act or the Securities Act of 1933, as amended, unless otherwise indicated in such registration statement or other document.

*** The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.

+ Indicates management contract or compensatory plan or arrangement.

Copies of any of the exhibits filed with the SEC in connection with this report may be obtained from the applicable registrant upon written request. The registrants agree to furnish to the SEC upon request any instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of total assets of such registrant and its subsidiaries on a consolidated basis.

Schedule I - Parent Company Financial Statements

EVERGY, INC.
Statements of Comprehensive Income of Parent Company

	2025	2024	2023
OPERATING EXPENSES:		(millions)	
Operating and maintenance	**$ 11.8**	$ 12.0	$ 6.2
Total Operating Expenses	**11.8**	12.0	6.2
INCOME FROM OPERATIONS	**(11.8)**	(12.0)	(6.2)
OTHER INCOME (EXPENSE)			
Equity in earnings from subsidiaries	**980.5**	965.8	804.7
Investment earnings	**0.2**	16.7	0.5
Other expense	**(2.4)**	—	(0.1)
Total Other Income, Net	**978.3**	982.5	805.1
Interest expense	**147.5**	124.8	91.6
INCOME BEFORE INCOME TAXES	**819.0**	845.7	707.3
Income tax benefit	**(36.6)**	(25.9)	(22.1)
NET INCOME	**$ 855.6**	$ 871.6	$ 729.4
COMPREHENSIVE INCOME			
NET INCOME	**$ 855.6**	$ 871.6	$ 729.4
OTHER COMPREHENSIVE INCOME			
Derivative hedging activity			
Gain on derivative hedging instruments	**0.6**	—	—
Income tax expense	**(0.1)**	—	—
Net gain on derivative hedging instruments	**0.5**	—	—
Reclassification to expenses, net of taxes	**5.4**	5.4	5.4
Derivative hedging activity, net of tax	**5.9**	5.4	5.4
Other comprehensive income (loss) from subsidiaries, net	**(0.1)**	0.4	(0.5)
Total other comprehensive income	**5.8**	5.8	4.9
COMPREHENSIVE INCOME	**$ 861.4**	$ 877.4	$ 734.3

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

EVERGY, INC.
Balance Sheets of Parent Company

	December 31	
	2025	2024
ASSETS	(millions, except share amounts)	
CURRENT ASSETS:		
Cash and cash equivalents	**$ 0.2**	$ 0.1
Accounts receivable from subsidiaries	**54.2**	58.4
Notes receivable from subsidiaries	**0.6**	0.6
Income taxes receivable	**16.3**	15.5
Prepaid expenses and other assets	**1.9**	3.0
Total Current Assets	**73.2**	77.6
OTHER ASSETS:		
Investment in subsidiaries	**13,368.6**	12,523.4
Deferred income taxes	**10.9**	13.3
Other	**2.4**	1.6
Total Other Assets	**13,381.9**	12,538.3
TOTAL ASSETS	**$ 13,455.1**	$ 12,615.9
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Commercial paper	**$ 500.2**	$ 75.4
Accounts payable to subsidiaries	**27.8**	30.8
Accrued interest	**12.3**	12.0
Other	**5.5**	6.0
Total Current Liabilities	**545.8**	124.2
LONG-TERM LIABILITIES:		
Long-term debt, net	**2,680.0**	2,674.1
Other	**8.0**	9.8
Total Long-Term Liabilities	**2,688.0**	2,683.9
Commitments and Contingencies (Note 15)		
EQUITY:		
Evergy, Inc. Shareholders' Equity:		
Common stock - 600,000,000 shares authorized, without par value, 230,262,674 and 229,983,615 shares issued	**7,273.1**	7,229.1
Retained earnings	**2,966.2**	2,602.5
Accumulated other comprehensive loss	**(18.0)**	(23.8)
Total Shareholders' Equity	**10,221.3**	9,807.8
TOTAL LIABILITIES AND EQUITY	**$ 13,455.1**	12,615.9

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

EVERGY, INC.
Statements of Cash Flows of Parent Company

	2025	2024	2023
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:		(millions)	
Net income	**$ 855.6**	$ 871.6	$ 729.4
Adjustments to reconcile income to net cash from operating activities:			
Non-cash compensation	**20.7**	15.3	17.7
Net deferred income taxes and credits	**0.7**	(0.1)	1.1
Equity in earnings from subsidiaries	**(980.5)**	(965.8)	(804.7)
Other	**7.0**	7.0	7.0
Changes in working capital items:			
Accounts receivable from subsidiaries	**4.2**	0.1	(14.2)
Income taxes receivable	**(0.8)**	(4.3)	(5.3)
Prepaid expenses and other current assets	**1.0**	(2.3)	1.5
Accounts payable to subsidiaries	**(3.0)**	—	11.0
Accrued interest	**0.3**	(4.7)	4.1
Other current liabilities	**0.4**	(0.3)	(1.9)
Cash dividends from subsidiaries	**250.0**	313.0	325.0
Changes in other assets	**—**	0.1	(0.8)
Changes in other liabilities	**3.0**	3.7	(2.9)
Cash Flows from Operating Activities	**158.6**	233.3	267.0
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Repayment of intercompany note	**—**	—	1.4
Net money pool lending	**—**	604.0	(574.5)
Proceeds from return of investments	**34.8**	—	—
Equity contribution	**(2.4)**	(3.1)	—
Cash Flows from (used in) Investing Activities	**32.4**	600.9	(573.1)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short term debt, net	**424.8**	75.4	(0.5)
Repayment of term loan facility	**—**	—	(500.0)
Proceeds from long-term debt	**—**	493.3	1,379.1
Retirements of long-term debt	**—**	(800.0)	—
Cash dividends paid	**(613.1)**	(596.7)	(569.6)
Issuance of common stock	**1.1**	—	—
Other financing activities	**(3.7)**	(6.1)	(3.3)
Cash Flows (used in) from Financing Activities	**(190.9)**	(834.1)	305.7
NET CHANGE IN CASH AND CASH EQUIVALENTS	**0.1**	0.1	(0.4)
CASH AND CASH EQUIVALENTS:			
Beginning of period	**0.1**	—	0.4
End of period	**$ 0.2**	$ 0.1	$ —

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

EVERGY, INC.
NOTES TO FINANCIAL STATEMENTS OF PARENT COMPANY

The Evergy, Inc. Notes to Consolidated Financial Statements in Part II, Item 8 should be read in conjunction with the Evergy, Inc. Parent Company Financial Statements.

1. ORGANIZATION AND BASIS OF PRESENTATION

The Evergy, Inc. Parent Company Financial Statements have been prepared to comply with Rule 12-04 of Regulation S-X.

Evergy, Inc. is a public holding company incorporated in 2017 and headquartered in Kansas City, Missouri. Evergy, Inc. operates primarily through the following wholly-owned direct subsidiaries listed below.

- Evergy Kansas Central, Inc. (Evergy Kansas Central) is an integrated, regulated electric utility that provides electricity to customers in the state of Kansas. Evergy Kansas Central has one active wholly-owned subsidiary with significant operations, Evergy Kansas South, Inc. (Evergy Kansas South).
- Evergy Metro, Inc. (Evergy Metro) is an integrated, regulated electric utility that provides electricity to customers in the states of Missouri and Kansas.
- Evergy Missouri West, Inc. (Evergy Missouri West) is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri.

Evergy, Inc.'s investments in subsidiaries are accounted for using the equity method. Fair value adjustments and goodwill related to the assets and liabilities acquired in the merger that created Evergy, Inc. are included in Evergy, Inc.'s Parent Company Financial Statements as of December 31, 2025 and for the year ended December 31, 2025. See Note 1 to the consolidated financial statement for additional information.

2. LONG-TERM DEBT

See Note 12 to the consolidated financial statements for additional information on Evergy, Inc.'s long-term debt.

3. GUARANTEES

See Note 16 to the consolidated financial statements for additional information regarding Evergy, Inc.'s guarantees.

4. DIVIDENDS

Cash dividends paid to Evergy, Inc. by its subsidiaries were $250.0 million for the year ended December 31, 2025, $313.0 million for the year ended December 31, 2024 and $325.0 million for the year ended December 31, 2023. See Note 18 to the consolidated financial statements for information regarding the dividend restrictions of Evergy, Inc. and its subsidiaries.

Schedule II - Valuation and Qualifying Accounts and Reserves

Evergy, Inc.
Valuation and Qualifying Accounts
Years Ended December 31, 2025, 2024 and 2023

Description	Balance At Beginning Of Period	Additions: Charged To Costs And Expenses	Additions: Charged To Other Accounts	Deductions	Balance At End Of Period
Year Ended December 31, 2025			(millions)		
Allowance for uncollectible accounts	$ 15.7	$ 20.4	$ 11.6 [a]	$ 32.4 [b]	$ 15.3
Tax valuation allowance	6.9	1.0	—	0.7 [c]	7.2
Year Ended December 31, 2024					
Allowance for uncollectible accounts	$ 24.2	$ 11.7	$ 12.3 [a]	$ 32.5 [b]	$ 15.7
Tax valuation allowance	14.8	0.6	—	8.5 [c]	6.9
Year Ended December 31, 2023					
Allowance for uncollectible accounts	$ 31.4	$ 15.4	$ 10.7 [a]	$ 33.3 [b]	$ 24.2
Tax valuation allowance	12.8	3.5	—	1.5 [c]	14.8

[a] Recoveries.
[b] Uncollectible accounts charged off.
[c] Reversal of tax valuation allowance.

Evergy Kansas Central, Inc.
Valuation and Qualifying Accounts
Years Ended December 31, 2025, 2024 and 2023

Description	Balance At Beginning Of Period	Additions: Charged To Costs And Expenses	Additions: Charged To Other Accounts	Deductions	Balance At End Of Period
Year Ended December 31, 2025			(millions)		
Allowance for uncollectible accounts	$ 7.8	$ 10.4	$ 4.7 [a]	$ 15.6 [b]	$ 7.3
Tax valuation allowance	2.7	—	—	—	2.7
Year Ended December 31, 2024					
Allowance for uncollectible accounts	$ 11.6	$ 6.6	$ 5.2 [a]	$ 15.6 [b]	$ 7.8
Tax valuation allowance	2.7	—	—	—	2.7
Year Ended December 31, 2023					
Allowance for uncollectible accounts	$ 16.9	$ 7.7	$ 4.7 [a]	$ 17.7 [b]	$ 11.6
Tax valuation allowance	—	2.7	—	—	2.7

[a] Recoveries.
[b] Uncollectible accounts charged off.

Evergy Metro, Inc.
Valuation and Qualifying Accounts
Years Ended December 31, 2025, 2024 and 2023

Description	Balance At Beginning Of Period	Additions: Charged To Costs And Expenses	Additions: Charged To Other Accounts	Deductions	Balance At End Of Period
			(millions)		
Year Ended December 31, 2025					
Allowance for uncollectible accounts	$ 5.8	$ 6.8	$ 4.9 [a]	$ 11.8 [b]	$ 5.7
Year Ended December 31, 2024					
Allowance for uncollectible accounts	$ 7.9	$ 4.5	$ 5.0 [a]	$ 11.6 [b]	$ 5.8
Year Ended December 31, 2023					
Allowance for uncollectible accounts	$ 9.3	$ 5.0	$ 4.1 [a]	$ 10.5 [b]	$ 7.9

[a] Recoveries.
[b] Uncollectible accounts charged off.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EVERGY, INC.

Date: February 18, 2026

By: /s/ David A. Campbell
David A. Campbell
Chairman, President and Chief Executive Officer

Pursuant to the requirements of the Securities Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title		Date
/s/ David A. Campbell David A. Campbell	Chairman, President and Chief Executive Officer (Principal Executive Officer)	))	
/s/ W. Bryan Buckler W. Bryan Buckler	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	))	
/s/ Matt Gummig Matt Gummig	Vice President and Chief Accounting Officer (Principal Accounting Officer)	))	
B. Anthony Isaac*	Director	)	
Paul M. Keglevic*	Director	)	
Mary L. Landrieu*	Director	)	February 18, 2026
Sandra A.J. Lawrence*	Director	)	
Ann D. Murtlow*	Director	)	
Dean A. Newton*	Director	)	
Sandra J. Price*	Director	)	
Jonathan D. Roth*	Director	)	
James Scarola*	Director	)	
Neal A. Sharma*	Director	)	
C. John Wilder*	Director	)	

*By /s/ David A. Campbell
David A. Campbell
Attorney-in-Fact*

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EVERGY KANSAS CENTRAL, INC.

Date: February 18, 2026

By: /s/ David A. Campbell
David A. Campbell
Chairman, President and Chief Executive Officer

Pursuant to the requirements of the Securities Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title		Date
/s/ David A. Campbell David A. Campbell	Chairman, President and Chief Executive Officer (Principal Executive Officer)	)	
/s/ W. Bryan Buckler W. Bryan Buckler	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	)	
/s/ Matt Gummig Matt Gummig	Vice President and Chief Accounting Officer (Principal Accounting Officer)	)	
B. Anthony Isaac*	Director	)	
Paul M. Keglevic*	Director	)	
Mary L. Landrieu*	Director	)	February 18, 2026
Sandra A.J. Lawrence*	Director	)	
Ann D. Murtlow*	Director	)	
Dean A. Newton*	Director	)	
Sandra J. Price*	Director	)	
Jonathan D. Roth*	Director	)	
James Scarola*	Director	)	
Neal A. Sharma*	Director	)	
C. John Wilder*	Director	)	

*By: /s/ David A. Campbell
David A. Campbell
Attorney-in-Fact*

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EVERGY METRO, INC.

Date: February 18, 2026

By: /s/ David A. Campbell
David A. Campbell
Chairman, President and Chief Executive Officer

Pursuant to the requirements of the Securities Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ David A. Campbell David A. Campbell	Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 18, 2026
/s/ W. Bryan Buckler W. Bryan Buckler	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	
/s/ Matt Gummig Matt Gummig	Vice President and Chief Accounting Officer (Principal Accounting Officer)	
B. Anthony Isaac*	Director	
Paul M. Keglevic*	Director	
Mary L. Landrieu*	Director	
Sandra A.J. Lawrence*	Director	
Ann D. Murtlow*	Director	
Dean A. Newton*	Director	
Sandra J. Price*	Director	
Jonathan D. Roth*	Director	
James Scarola*	Director	
Neal A. Sharma*	Director	
C. John Wilder*	Director	

*By /s/ David A. Campbell
David A. Campbell
Attorney-in-Fact*

EVERGY, INC.
2026 RESTRICTED STOCK UNIT AGREEMENT
(TIME-BASED VESTING)

Grantor:	Evergy, Inc. or the Company
Grantee:	
Grant Date:	
Restricted Stock Units (RSUs) Granted:	

THIS RESTRICTED STOCK UNIT AGREEMENT (the "Agreement") is entered into as of the Grant Date, by and between the Company and the Grantee with respect to the RSUs granted herein, as such terms are defined in the chart above. All capitalized terms in this Agreement that are not defined herein shall have the meanings ascribed to such terms in the Company's Long-Term Incentive Plan, as amended and restated from time to time (the "Plan").

WHEREAS, Grantee is employed by the Company or one of its Subsidiaries and the Company desires to (i) encourage Grantee to acquire an interest in the growth and performance of the Company, (ii) provide Grantee with an incentive to enhance the value of the Company for the benefit of its customers and shareholders and (iii) encourage Grantee to remain in the employ of the Company as one of the key employees upon whom the Company's success depends; and

WHEREAS, the Company wishes to grant to Grantee, and Grantee wishes to accept, an Award of Restricted Stock Units, pursuant to the terms and conditions of the Plan and this Agreement.

NOW, THEREFORE, in consideration of the covenants and agreements herein contained, the parties agree as follows:

1. Restricted Stock Unit Award. The Company hereby grants to Grantee an Award of Restricted Stock Units ("RSUs") defined in the chart above. Each RSU represents the right to receive one Share, subject to the terms and conditions set forth in this Agreement and the Plan, the terms and conditions of which are incorporated herein by reference.

2. Terms and Conditions. In addition to the terms and conditions in the Plan, this Award of RSUs is subject to the following terms and conditions:

   a. Grant of RSUs. The RSUs granted hereunder shall be credited to Grantee's RSU Account as of the Grant Date. The RSU Account shall be maintained for recordkeeping purposes only and the Company shall not be obligated to segregate or set aside assets representing securities or other amounts credited to Grantee's RSU Account. All amounts credited to the RSU Account shall continue for all purposes to be part of the general assets of the Company.

   b. Vesting of RSUs. The RSUs will vest on the third anniversary of the Grant Date (the "Vesting Date"), provided that Grantee remains continuously employed by the Company or one of its Subsidiaries (except as provided in paragraph 2.c and 2.d of this Agreement)

during the entire period that begins on the Grant Date and ends on the Vesting Date (the "Restricted Period").

c. Termination of Employment during the Restricted Period for Death or Disability. If Grantee experiences a termination of employment on account of Grantee's death or Disability before the end of the Restricted Period, then as of the date of Grantee's termination of employment, the unvested RSUs (and Dividend Equivalents) shall vest.

d. Termination of Employment during the Restricted Period for Retirement. If Grantee experiences a termination of employment on account of Grantee's Retirement (as defined below) before the end of the Restricted Period, no immediate vesting shall occur at the time of Grantee's Retirement but, following the end of the Restricted Period, a pro rata portion of the RSUs (and Dividend Equivalents) shall vest. Such pro rata portion shall be determined by multiplying (i) the number of RSUs by (ii) a fraction, the numerator of which is the total number of days from the Grant Date to the Grantee's Retirement, and the denominator of which is the total number of days between the Grant Date and the Vesting Date. For purposes of this Agreement, "Retirement" means Grantee's separation from service after (i) attainment of the age of sixty (60) and having five (5) years of service with the Company or its Subsidiaries, and (ii) Grantee having provided a minimum of six-months' advance notice to the Company of Grantee's Retirement.

e. Limits on Transfer of RSUs. Subject to any exceptions set forth in the Plan, during the Restricted Period and until such time as the RSUs are settled in accordance with the terms of this Agreement, neither the RSUs nor any rights relating thereto may be assigned, alienated, pledged, attached, sold or otherwise transferred or encumbered by Grantee. Any attempt to assign, alienate, pledge, attach, sell or otherwise transfer or encumber the RSUs or the rights relating thereto shall be wholly ineffective and, if any such attempt is made, the RSUs will be immediately forfeited by Grantee and all of Grantee's rights to the RSUs shall immediately terminate without any payment, settlement, or consideration by the Company.

f. No Rights as a Shareholder until RSUs Settled. Grantee shall not have any rights of a shareholder with respect to the Shares underlying the RSUs unless and until the RSUs vest and are settled by the issuance of Shares.

g. Dividend Equivalents. If during the Restricted Period the Company declares a cash dividend on Shares, then, as of any dividend payment date, Grantee shall receive an additional number of RSUs (including fractional RSUs), which shall be credited to the RSU Account, equal to the quotient obtained by dividing the aggregate cash amount that would have been paid as dividends if each RSU then credited to the RSU Account on the dividend payment date were a Share, by the closing price of a Share on the trading date immediately preceding the dividend payment date. Any additional RSU credited to the Grantee's RSU Account under this Section 2.g. shall be subject to the same vesting and forfeiture conditions as the original RSUs granted on the Grant Date and shall be settled, if at all, on the Vesting Date. If, during the Restricted Period, the Company declares a stock dividend on Shares, then the Grantee may be eligible for additional Shares on the Vesting Date (or earlier as determined by the Committee) based on the number of RSUs credited to the Grantee's RSU Account in accordance with Section 16.H of the Plan.

When the Vesting Date falls between a dividend record date and the dividend payment date, the additional number of RSUs (including fractional RSUs), which shall be credited to the RSU account as dividend equivalents will be calculated as set forth above, except that the share price will be calculated based on the date immediately preceding the dividend *record* date instead of the date immediately preceding the dividend *payment* date, and the resulting Shares are issued concurrently with the other Shares vesting on the Vesting Date.

h. Settlement of RSUs. No later than 30 days after the earlier of (i) the Vesting Date or (ii) Grantee's termination of employment due to death or Disability, the Company shall issue and deliver to Grantee, or in the event of Grantee's death the beneficiary designated in writing by Grantee in accordance with instructions provided by the Company (or in the event Grantee has not designated a beneficiary, Grantee's estate), a number of Shares equal to the aggregate number of vested RSUs (with any fractional Share underlying the vested RSUs on the settlement date being settled by delivering to Grantee a cash payment equal to the closing price of a Share on the Vesting Date or the date of Grantee's termination of employment, as applicable, multiplied by the number of fractional vested RSUs) then credited to Grantee's RSU Account. The Committee may, in its sole discretion, settle any vested RSUs by delivering to Grantee (or Grantee's beneficiary or estate in the event of Grantee's death) an amount of cash equal to the closing price of a Share on Vesting Date or the date of Grantee's termination of employment, as applicable, multiplied by the number of vested RSUs (and any fraction thereof) held by Grantee.

i. Tax Withholding on RSU Settlement. No Shares will be delivered under this Agreement until either (i) Grantee has paid to the Company the amount that must be withheld under federal, state and local income and employment tax laws or (ii) Grantee and the Company have made satisfactory provision for the payment of such taxes. Unless otherwise not permitted by the Committee (which may disallow Share withholding at any time) or contrary to an election Grantee submitted to the Company in accordance with established Company policy, the Company shall first withhold such taxes from the Shares (valued at their Fair Market Value) otherwise eligible to be delivered under this Award, if any.

j. 280G Best Net. Notwithstanding anything in this Agreement to the contrary, in the event that (A) there is a Change in Control, and (B) the receipt of all payments, distributions or benefits (including, without limitation, accelerated vesting of the RSUs) by the Company in the nature of compensation to or for Grantee's benefit, whether paid or payable pursuant to this Agreement or otherwise (a "Payment"), would subject Grantee to the excise tax under Section 4999 of the Code by virtue of Section 280G of the Code, the Company shall reduce the number of RSUs which become vested on account of the Change in Control if such reduction would result in Grantee having a greater net after-tax Payment than if such RSUs were not reduced and the Payment, or any portion thereof, is subjected to the excise tax under Section 4999 of the Code.

k. Clawback. This Award will be subject to certain provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 ("Dodd-Frank") and any other compensation clawback or recoupment policy that the Committee has adopted or is required to adopt pursuant to the listing standards of any national securities exchange on which the Company's securities are listed or as is otherwise required by Dodd Frank or

any other applicable law. Grantee acknowledges that the Award or any compensation derived therefrom may be forfeited and/or recouped by the Company in accordance with any policies and procedures adopted by the Committee in order to comply with Dodd Frank or other clawback or recoupment policy. Without limitation, the Company may, in its discretion, or shall as required by law, (i) seek repayment from the Grantee; (ii) reduce the amount that would otherwise be payable to the Grantee under current or future Awards; (iii) withhold future equity grants or salary increases; (iv) pursue other available legal remedies, or (v) any combination of these actions. The Company's clawback or recoupment policy may require the Company take such recoupment actions against the Grantee whether or not such Grantee engaged in any misconduct or was otherwise at fault with respect to any event or circumstance giving rise to such clawback action.

The Company will, to the full extent permitted by law, have the discretion based on the particular facts and circumstances to require that the Grantee reimburse the Company for all or any portion of any Awards if and to the extent the Awards reflected the achievement of financial results that were subsequently the subject of a restatement, or the achievement of other objectives that were subsequently found to be inaccurately measured, and a lower Award would have occurred based upon the restated financial results or accurately measured objectives. The Company may, in its discretion, (i) seek repayment from the Grantee; (ii) reduce the amount that would otherwise be payable to the Grantee under current or future Awards; (iii) withhold future equity grants or salary increases; (iv) pursue other available legal remedies or (v) any combination of these actions. The Company may take such actions against any Grantee, whether or not such Grantee engaged in any misconduct or was otherwise at fault with respect to such restatement or inaccurate measurement.

3. Amendment. This Agreement may be amended only in the manner provided by the Company evidencing both parties' agreement to the amendment. This Agreement may also be amended, without prior notice to Grantee and without Grantee's consent before any Change in Control by the Committee if the Committee in good faith determines the amendment does not materially adversely affect any of Grantee's rights under this Agreement.

4. Entire Agreement. This Agreement contains the entire agreement between Grantee and the Company with respect to the subject matter hereof and supersedes all prior agreements or understandings between the parties relating thereto.

5. Miscellaneous. This Agreement may be executed in counterparts, each of which shall be deemed to be an original, and shall constitute the same Agreement. This Agreement shall become a binding agreement between Grantor and Grantee when a counterpart of this Agreement has been either (i) signed by each party, or (ii) accepted and acknowledged electronically by each party, or a combination thereof. An electronic signature of Grantor or Grantee on DocuSign or other signing platform, or a "box check" acceptance and acknowledgement on the E*TRADE or Morgan Stanley or other platform, transmitted electronically, shall be deemed to be original signatures of such parties for all purposes, shall constitute an intent to be bound by the terms and conditions of this Agreement, and effective execution and delivery of this Agreement.

[Signature Page Follows]

EVERGY, INC.

By: _____
Lesley L. Elwell
Senior Vice President, Chief People Officer

EVERGY, INC.
2026 RESTRICTED STOCK UNIT AGREEMENT
(TIME-BASED VESTING - ALTERNATE)

Grantor:	Evergy, Inc. or the Company
Grantee:	
Grant Date:	
Restricted Stock Units (RSUs) Granted:	

THIS RESTRICTED STOCK UNIT AGREEMENT (the "Agreement") is entered into as of the Grant Date, by and between the Company and the Grantee with respect to the RSUs granted herein, as such terms are defined in the chart above. All capitalized terms in this Agreement that are not defined herein shall have the meanings ascribed to such terms in the Company's Long-Term Incentive Plan, as amended and restated from time to time (the "Plan").

WHEREAS, Grantee is employed by the Company or one of its Subsidiaries and the Company desires to (i) encourage Grantee to acquire an interest in the growth and performance of the Company, (ii) provide Grantee with an incentive to enhance the value of the Company for the benefit of its customers and shareholders and (iii) encourage Grantee to remain in the employ of the Company as one of the key employees upon whom the Company's success depends; and

WHEREAS, the Company wishes to grant to Grantee, and Grantee wishes to accept, an Award of Restricted Stock Units, pursuant to the terms and conditions of the Plan and this Agreement.

NOW, THEREFORE, in consideration of the covenants and agreements herein contained, the parties agree as follows:

1. Restricted Stock Unit Award. The Company hereby grants to Grantee an Award of Restricted Stock Units ("RSUs") defined in the chart above. Each RSU represents the right to receive one Share, subject to the terms and conditions set forth in this Agreement and the Plan, the terms and conditions of which are incorporated herein by reference.

2. Terms and Conditions. In addition to the terms and conditions in the Plan, this Award of RSUs is subject to the following terms and conditions:

   a. Grant of RSUs. The RSUs granted hereunder shall be credited to Grantee's RSU Account as of the Grant Date. The RSU Account shall be maintained for recordkeeping purposes only and the Company shall not be obligated to segregate or set aside assets representing securities or other amounts credited to Grantee's RSU Account. All amounts credited to the RSU Account shall continue for all purposes to be part of the general assets of the Company.

   b. Vesting of RSUs. The RSUs will vest on the third anniversary of the Grant Date (the "Vesting Date"), provided that Grantee remains continuously employed by the Company or one of its Subsidiaries (except as provided in paragraph 2.c and 2.d of this Agreement)

during the entire period that begins on the Grant Date and ends on the Vesting Date (the "Restricted Period").

c. Termination of Employment during the Restricted Period for Death or Disability. If Grantee experiences a termination of employment on account of Grantee's death or Disability before the end of the Restricted Period, then as of the date of Grantee's termination of employment, the unvested RSUs (and Dividend Equivalents) shall vest.

d. Termination of Employment during the Restricted Period for Retirement or Extended Retirement. If Grantee experiences a termination of employment on account of Retirement or Extended Retirement (each as defined below) before the end of the Restricted Period, Grantee shall receive the vesting benefits described in Sections 2(d)(i) or 2(d)(ii) below, as applicable. In all cases, settlement of any vested RSUs (and Dividend Equivalents) shall occur on the originally scheduled Vesting Date, with no acceleration of payment.

(i) Pro Rata Vesting (Retirement).

If the Grantee's termination of employment qualifies as a Retirement, no RSUs shall immediately settle upon termination. Following the end of the Restricted Period, a pro rata portion of the RSUs (and Dividend Equivalents) that would have vested had the Grantee remained employed through the Vesting Date, based on actual performance results, shall vest and be settled on the Vesting Date.

The pro rata portion shall be determined by multiplying: (A) the number of RSUs that would have vested on the Vesting Date absent termination by (B) a fraction, the numerator of which is the number of days from the Grant Date through the date of Retirement, and the denominator of which is the number of days from the Grant Date through the Vesting Date.

Definition of Retirement.

For purposes of Section 2(d)(i), "Retirement" means the Grantee's separation from service: on or after attaining age sixty (60); after completing at least five (5) years of service with the Company or its Subsidiaries; and after providing the Company with at least six (6) months' advance written notice of the Grantee's Retirement

(ii) Full Vesting (Extended Retirement).

If the Grantee's termination of employment qualifies as an Extended Retirement, no RSUs shall immediately settle upon termination. Following the end of the Restricted Period, all RSUs (and Dividend Equivalents) shall vest based on actual performance results and shall be settled on the Vesting Date, subject to satisfaction of the conditions for Extended Retirement.

Definition of Extended Retirement.

For purposes of Section 2(d)(ii), "Extended Retirement" means the Grantee's separation from service only if all of the following conditions are satisfied:

A. The Grantee has attained age sixty-two (62) and completed at least five (5) years of service with the Company or its Subsidiaries;

B. The Grantee has provided the required advance written notice as follows:

For Named Executive Officers ("NEOs") and Section 16 officers, notice determined to be reasonable by the Compensation & Leadership Development Committee ("CLD Committee");

For all other Grantees, at least six (6) months' advance written notice of Extended Retirement;

C. At least one (1) year has elapsed from the Grant Date to the date of separation from service; provided, however, that RSUs granted less than one year prior to separation shall vest pro rata in accordance with Section 2(d)(i);

D. The Grantee has submitted a transition plan approved as follows:

For the Chief Executive Officer ("CEO"): by the Board; For Section 16 Officers (other than the CEO): by the CLD Committee; For all other officers: by the CEO; For non-officer Grantees: by an officer; and

E. For any Grantee who is an NEO or a Section 16 Officer, the CLD Committee has approved, in its sole discretion, the Grantee's eligibility for Extended Retirement.

Additional Condition.

Notwithstanding the foregoing, a Grantee shall not be eligible for Extended Retirement unless, if requested by the Company, the Grantee timely executes—and does not revoke within any applicable revocation period—a restrictive covenant and release of claims agreement, in a form provided by the Company, including confidentiality, release of claims, non-solicitation, non-competition, and non-disparagement provisions.

e. Limits on Transfer of RSUs. Subject to any exceptions set forth in the Plan, during the Restricted Period and until such time as the RSUs are settled in accordance with the terms of this Agreement, neither the RSUs nor any rights relating thereto may be assigned, alienated, pledged, attached, sold or otherwise transferred or encumbered by Grantee. Any attempt to assign, alienate, pledge, attach, sell or otherwise transfer or encumber the RSUs or the rights relating thereto shall be wholly ineffective and, if any such attempt is made, the RSUs will be immediately forfeited by Grantee and all of Grantee's rights to the RSUs shall immediately terminate without any payment, settlement, or consideration by the Company.

f. No Rights as a Shareholder until RSUs Settled. Grantee shall not have any rights of a shareholder with respect to the Shares underlying the RSUs unless and until the RSUs vest and are settled by the issuance of Shares.

g. Dividend Equivalents. If during the Restricted Period the Company declares a cash dividend on Shares, then, as of any dividend payment date, Grantee shall receive an

additional number of RSUs (including fractional RSUs), which shall be credited to the RSU Account, equal to the quotient obtained by dividing the aggregate cash amount that would have been paid as dividends if each RSU then credited to the RSU Account on the dividend payment date were a Share, by the closing price of a Share on the trading date immediately preceding the dividend payment date. Any additional RSU credited to the Grantee's RSU Account under this Section 2.g. shall be subject to the same vesting and forfeiture conditions as the original RSUs granted on the Grant Date and shall be settled, if at all, on the Vesting Date. If, during the Restricted Period, the Company declares a stock dividend on Shares, then the Grantee may be eligible for additional Shares on the Vesting Date (or earlier as determined by the Committee) based on the number of RSUs credited to the Grantee's RSU Account in accordance with Section 16.H of the Plan. When the Vesting Date falls between a dividend record date and the dividend payment date, the additional number of RSUs (including fractional RSUs), which shall be credited to the RSU account as dividend equivalents will be calculated as set forth above, except that the share price will be calculated based on the date immediately preceding the dividend *record* date instead of the date immediately preceding the dividend *payment* date, and the resulting Shares are issued concurrently with the other Shares vesting on the Vesting Date.

h. Settlement of RSUs. No later than 30 days after the earlier of (i) the Vesting Date or (ii) Grantee's termination of employment due to death or Disability, the Company shall issue and deliver to Grantee, or in the event of Grantee's death the beneficiary designated in writing by Grantee in accordance with instructions provided by the Company (or in the event Grantee has not designated a beneficiary, Grantee's estate), a number of Shares equal to the aggregate number of vested RSUs (with any fractional Share underlying the vested RSUs on the settlement date being settled by delivering to Grantee a cash payment equal to the closing price of a Share on the Vesting Date or the date of Grantee's termination of employment, as applicable, multiplied by the number of fractional vested RSUs) then credited to Grantee's RSU Account. The Committee may, in its sole discretion, settle any vested RSUs by delivering to Grantee (or Grantee's beneficiary or estate in the event of Grantee's death) an amount of cash equal to the closing price of a Share on Vesting Date or the date of Grantee's termination of employment, as applicable, multiplied by the number of vested RSUs (and any fraction thereof) held by Grantee.

i. Tax Withholding on RSU Settlement. No Shares will be delivered under this Agreement until either (i) Grantee has paid to the Company the amount that must be withheld under applicable federal, state, and local income and employment tax laws (including obligations arising under Sections 3101, 3121(a), and 3121(v)(2) of the Internal Revenue Code), or (ii) Grantee and the Company have made satisfactory provision for the payment of such taxes. Such withholding obligations may arise prior to the settlement or delivery of Shares. To satisfy such withholding obligations, the Company may, in its discretion, deduct amounts from any compensation or other amounts payable to Grantee, require Grantee to remit cash to the Company, require Grantee to make other arrangements satisfactory to the Company, or use any combination of the foregoing. Unless otherwise determined by the Committee (which may disallow Share withholding at any time) or contrary to an election submitted by Grantee in accordance with established Company policy, the Company may withhold such taxes from the Shares (valued at their Fair Market Value) otherwise eligible to be delivered under this Award, if any.

j. 280G Best Net. Notwithstanding anything in this Agreement to the contrary, in the event that (A) there is a Change in Control, and (B) the receipt of all payments, distributions or benefits (including, without limitation, accelerated vesting of the RSUs) by the Company in the nature of compensation to or for Grantee's benefit, whether paid or payable pursuant to this Agreement or otherwise (a "Payment"), would subject Grantee to the excise tax under Section 4999 of the Code by virtue of Section 280G of the Code, the Company shall reduce the number of RSUs which become vested on account of the Change in Control if such reduction would result in Grantee having a greater net after-tax Payment than if such RSUs were not reduced and the Payment, or any portion thereof, is subjected to the excise tax under Section 4999 of the Code.

k. Clawback. This Award will be subject to certain provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 ("Dodd-Frank") and any other compensation clawback or recoupment policy that the Committee has adopted or is required to adopt pursuant to the listing standards of any national securities exchange on which the Company's securities are listed or as is otherwise required by Dodd Frank or any other applicable law. Grantee acknowledges that the Award or any compensation derived therefrom may be forfeited and/or recouped by the Company in accordance with any policies and procedures adopted by the Committee in order to comply with Dodd Frank or other clawback or recoupment policy. Without limitation, the Company may, in its discretion, or shall as required by law, (i) seek repayment from the Grantee; (ii) reduce the amount that would otherwise be payable to the Grantee under current or future Awards; (iii) withhold future equity grants or salary increases; (iv) pursue other available legal remedies, or (v) any combination of these actions. The Company's clawback or recoupment policy may require the Company take such recoupment actions against the Grantee whether or not such Grantee engaged in any misconduct or was otherwise at fault with respect to any event or circumstance giving rise to such clawback action.

The Company will, to the full extent permitted by law, have the discretion based on the particular facts and circumstances to require that the Grantee reimburse the Company for all or any portion of any Awards if and to the extent the Awards reflected the achievement of financial results that were subsequently the subject of a restatement, or the achievement of other objectives that were subsequently found to be inaccurately measured, and a lower Award would have occurred based upon the restated financial results or accurately measured objectives. The Company may, in its discretion, (i) seek repayment from the Grantee; (ii) reduce the amount that would otherwise be payable to the Grantee under current or future Awards; (iii) withhold future equity grants or salary increases; (iv) pursue other available legal remedies or (v) any combination of these actions. The Company may take such actions against any Grantee, whether or not such Grantee engaged in any misconduct or was otherwise at fault with respect to such restatement or inaccurate measurement.

3. Amendment. This Agreement may be amended only in the manner provided by the Company evidencing both parties' agreement to the amendment. This Agreement may also be amended, without prior notice to Grantee and without Grantee's consent before any Change in Control by the Committee if the Committee in good faith determines the amendment does not materially adversely affect any of Grantee's rights under this Agreement.

4. Entire Agreement. This Agreement contains the entire agreement between Grantee and the Company with respect to the subject matter hereof and supersedes all prior agreements or understandings between the parties relating thereto.

5. Miscellaneous. This Agreement may be executed in counterparts, each of which shall be deemed to be an original, and shall constitute the same Agreement. This Agreement shall become a binding agreement between Grantor and Grantee when a counterpart of this Agreement has been either (i) signed by each party, or (ii) accepted and acknowledged electronically by each party, or a combination thereof. An electronic signature of Grantor or Grantee on DocuSign or other signing platform, or a "box check" acceptance and acknowledgement on the E*TRADE or Morgan Stanley or other platform, transmitted electronically, shall be deemed to be original signatures of such parties for all purposes, shall constitute an intent to be bound by the terms and conditions of this Agreement, and effective execution and delivery of this Agreement.

[*Signature Page Follows*]

EVERGY, INC.

By: _____
Lesley L. Elwell
Senior Vice President, Chief People Officer

Exhibit 10.14

EVERGY, INC.
2026 RESTRICTED STOCK UNIT AGREEMENT
(PERFORMANCE-BASED VESTING)

Grantor:	Evergy, Inc. or the Company
Grantee:	
Grant Date:	
Target Award of Restricted Stock Units (RSUs):	

THIS RESTRICTED STOCK UNIT AGREEMENT (the "Agreement") is entered into as of the Grant Date, by and between the Company and the Grantee with respect to the Target Award of RSUs granted herein, as such terms are defined in the chart above. All capitalized terms in this Agreement that are not defined herein shall have the meanings ascribed to such terms in the Company's Long-Term Incentive Plan, as amended and restated from time to time (the "Plan").

WHEREAS, Grantee is employed by the Company or one of its Subsidiaries and the Company desires to (i) encourage Grantee to acquire an interest in the growth and performance of the Company, (ii) provide Grantee with an incentive to enhance the value of the Company for the benefit of its customers and shareholders and (iii) encourage Grantee to remain in the employ of the Company as one of the key employees upon whom the Company's success depends; and

WHEREAS, the Company wishes to grant to Grantee, and Grantee wishes to accept, an Award of Restricted Stock Units, pursuant to the terms and conditions of the Plan and this Agreement.

NOW, THEREFORE, in consideration of the covenants and agreements herein contained, the parties agree as follows:

1. Restricted Stock Unit Award. The Company hereby grants to Grantee a target Award of Restricted Stock Units ("RSUs") defined in the chart above. Each RSU represents the right to receive one Share, subject to the terms and conditions set forth in this Agreement and the Plan, the terms and conditions of which are incorporated herein by reference.

2. Terms and Conditions. In addition to the terms and conditions in the Plan, this Award of RSUs is subject to the following terms and conditions:

   a. Grant of RSUs. The RSUs granted hereunder shall be credited to Grantee's RSU Account as of the Grant Date. The RSU Account shall be maintained for recordkeeping purposes only and the Company shall not be obligated to segregate or set aside assets representing securities or other amounts credited to Grantee's RSU Account. All amounts credited to the RSU Account shall continue for all purposes to be part of the general assets of the Company.

   b. Vesting of RSUs. The RSUs will vest on the later of (i) the third anniversary of the Grant Date and (ii) the date on which the Company files audited financial statements

with the Securities and Exchange Commission that include all performance periods set forth in Appendices A-C (the "Vesting Date"), provided that Grantee remains continuously employed by the Company or one of its Subsidiaries (except as provided in paragraph 2.c and 2.d of this Agreement) during the entire period that begins on the Grant Date and ends on the Vesting Date (the "Restricted Period"). The number of RSUs that vest on the Vesting Date will be determined in the manner described in Appendices A-C.

c. Termination of Employment during the Restricted Period for Death or Disability. If Grantee experiences a termination of employment on account of Grantee's death or Disability before the end of the Restricted Period, then as of the date of Grantee's termination of employment, that number of RSUs (and Dividend Equivalents) which would have vested if the target level of goal achievement for the Restricted Period had been met shall vest.

d. Termination of Employment during the Restricted Period for Retirement. If Grantee experiences a termination of employment on account of Grantee's Retirement (as defined below) before the end of the Restricted Period, no immediate vesting shall occur at the time of Grantee's Retirement but, following the end of the Restricted Period, a pro rata portion of the number of RSUs (and Dividend Equivalents) that would have vested if Grantee had not separated from service and based on the actual level of goal achievement during the Restricted Period shall vest. Such pro rata portion shall be determined by multiplying (i) the number of RSUs that would have vested on the Vesting Date if Grantee had not experienced a termination of employment by (ii) a fraction, the numerator of which is the total number of days from the Grant Date to the Grantee's Retirement, and the denominator of which is the total number of days between the Grant Date and the Vesting Date. For purposes of this Agreement, "Retirement" means Grantee's separation from service after (i) attainment of the age of sixty (60) and having five (5) years of service with the Company or its Subsidiaries, and (ii) Grantee having provided a minimum of six-months' advance notice to the Company of Grantee's Retirement.

e. Limits on Transfer of RSUs. Subject to any exceptions set forth in the Plan, during the Restricted Period and until such time as the RSUs are settled in accordance with the terms of this Agreement, neither the RSUs nor any rights relating thereto may be assigned, alienated, pledged, attached, sold or otherwise transferred or encumbered by Grantee. Any attempt to assign, alienate, pledge, attach, sell or otherwise transfer or encumber the RSUs or the rights relating thereto shall be wholly ineffective and, if any such attempt is made, the RSUs will be immediately forfeited by Grantee and all of Grantee's rights to the RSUs shall immediately terminate without any payment, settlement, or consideration by the Company.

f. No Rights as a Shareholder until RSUs Settled. Grantee shall not have any rights of a shareholder with respect to the Shares underlying the RSUs unless and until the RSUs vest and are settled by the issuance of Shares.

g. Dividend Equivalents. Each RSU that becomes vested pursuant to this Agreement includes the right to receive dividend equivalents in an amount equal to the amount of

the cash dividends that Grantee would have received if Grantee owned that number Shares represented by the vested RSUs during the Restricted Period and before the RSUs were settled. These dividend equivalents, if any, shall be accrued and paid to Grantee in cash, less taxes, at the time the RSUs are settled in accordance with paragraph 2.h. below. If, during the Restricted Period, the Company declares a stock dividend on Shares, then the Grantee may be eligible for additional Shares at the time the RSUs are settled in accordance with paragraph 2.h. below (or earlier as determined by the Committee) based on the number of RSUs credited to the Grantee's RSU Account in accordance with Section 16.H of the Plan.

When the Vesting Date falls between a dividend record date and the dividend payment date, the additional number of RSUs (including fractional RSUs), which shall be credited to the RSU account as dividend equivalents will be calculated as set forth above, except that the share price will be calculated based on the date immediately preceding the dividend *record* date instead of the date immediately preceding the dividend *payment* date, and the resulting Shares are issued concurrently with the other Shares vesting on the Vesting Date.

h. Settlement of RSUs. No later than 30 days after the earlier of (i) the Vesting Date or (ii) Grantee's termination of employment due to death or Disability, the Company shall issue and deliver to Grantee, or in the event of Grantee's death the beneficiary designated in writing by Grantee in accordance with instructions provided by the Company (or in the event Grantee has not designated a beneficiary, Grantee's estate), a number of Shares equal to the aggregate number of vested RSUs (with any fractional Share underlying the vested RSUs on the settlement date being settled by delivering to Grantee a cash payment equal to the closing price of a Share on the Vesting Date or the date of Grantee's termination of employment, as applicable, multiplied by the number of fractional vested RSUs) then credited to Grantee's RSU Account. The Committee may, in its sole discretion, settle any vested RSUs by delivering to Grantee (or Grantee's beneficiary or estate in the event of Grantee's death) an amount of cash equal to the closing price of a Share on the Vesting Date or the date of Grantee's termination of employment, as applicable, multiplied by the number of vested RSUs (and any fraction thereof) held by Grantee.

i. Tax Withholding on RSU Settlement. No Shares will be delivered under this Agreement until either (i) Grantee has paid to the Company the amount that must be withheld under federal, state and local income and employment tax laws or (ii) Grantee and the Company have made satisfactory provision for the payment of such taxes. Unless otherwise not permitted by the Committee (which may disallow Share withholding at any time) or contrary to an election Grantee submitted to the Company in accordance with established Company policy, the Company shall first withhold such taxes from the Shares (valued at their Fair Market Value) otherwise eligible to be delivered under this Award, if any.

j. 280G Best Net. Notwithstanding anything in this Agreement to the contrary, in the event that (A) there is a Change in Control, and (B) the receipt of all payments, distributions or benefits (including, without limitation, accelerated vesting of the RSUs) by the Company in the nature of compensation to or for Grantee's benefit,

whether paid or payable pursuant to this Agreement or otherwise (a "Payment"), would subject Grantee to the excise tax under Section 4999 of the Code by virtue of Section 280G of the Code, the Company shall reduce the number of RSUs which become vested on account of the Change in Control if such reduction would result in Grantee having a greater net after-tax Payment than if such RSUs were not reduced and the Payment, or any portion thereof, is subjected to the excise tax under Section 4999 of the Code.

k. Clawback. This Award will be subject to certain provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 ("Dodd-Frank") and any other compensation clawback or recoupment policy that the Committee has adopted or is required to adopt pursuant to the listing standards of any national securities exchange on which the Company's securities are listed or as is otherwise required by Dodd Frank or any other applicable law. Grantee acknowledges that the Award or any compensation derived therefrom may be forfeited and/or recouped by the Company in accordance with any policies and procedures adopted by the Committee in order to comply with Dodd Frank or other clawback or recoupment policy. Without limitation, the Company may, in its discretion, or shall as required by law, (i) seek repayment from the Grantee; (ii) reduce the amount that would otherwise be payable to the Grantee under current or future Awards; (iii) withhold future equity grants or salary increases; (iv) pursue other available legal remedies, or (v) any combination of these actions. The Company's clawback or recoupment policy may require the Company take such recoupment actions against the Grantee whether or not such Grantee engaged in any misconduct or was otherwise at fault with respect to any event or circumstance giving rise to such clawback action.

The Company will, to the full extent permitted by law, have the discretion based on the particular facts and circumstances to require that the Grantee reimburse the Company for all or any portion of any Awards if and to the extent the Awards reflected the achievement of financial results that were subsequently the subject of a restatement, or the achievement of other objectives that were subsequently found to be inaccurately measured, and a lower Award would have occurred based upon the restated financial results or accurately measured objectives. The Company may, in its discretion, (i) seek repayment from the Grantee; (ii) reduce the amount that would otherwise be payable to the Grantee under current or future Awards; (iii) withhold future equity grants or salary increases; (iv) pursue other available legal remedies or (v) any combination of these actions. The Company may take such actions against any Grantee, whether or not such Grantee engaged in any misconduct or was otherwise at fault with respect to such restatement or inaccurate measurement.

3. Amendment. This Agreement may be amended only in the manner provided by the Company evidencing both parties' agreement to the amendment. This Agreement may also be amended, without prior notice to Grantee and without Grantee's consent before any Change in Control by the Committee if the Committee in good faith determines the amendment does not materially adversely affect any of Grantee's rights under this Agreement.

4. Entire Agreement. This Agreement contains the entire agreement between Grantee and the Company with respect to the subject matter hereof and supersedes all prior agreements or understandings between the parties relating thereto.

5. Miscellaneous. This Agreement may be executed in counterparts, each of which shall be deemed to be an original, and shall constitute the same Agreement. This Agreement shall become a binding agreement between Grantor and Grantee when a counterpart of this Agreement has been either (i) signed by each party, or (ii) accepted and acknowledged electronically by each party, or a combination thereof. An electronic signature of Grantor or Grantee on DocuSign or other signing platform, or a "box check" acceptance and acknowledgement on the E*TRADE or Morgan Stanley or other platform, transmitted electronically, shall be deemed to be original signatures of such parties for all purposes, shall constitute an intent to be bound by the terms and conditions of this Agreement, and effective execution and delivery of this Agreement.

[Signature Page Follows]

EVERGY, INC.

By: _____
Lesley L. Elwell
Senior Vice President, Chief People Officer

APPENDIX A

January 1, 2026 – December 31, 2028 Performance Criteria

Relative Total Shareholder Return: Fifty-seven and one tenth percent (57.1%) of the target RSUs subject to this Agreement shall become vested based upon the Company's relative total shareholder return from January 1, 2026 to December 31, 2028, calculated in the following manner:

Objective	(0%)	Threshold (25%)	Target (100%)	Stretch (150%)	Superior (200%)
Relative Total Shareholder Return (TSR) versus EEI Index[1] (Interpolation applicable)	< 25th Percentile	25th Percentile	50th Percentile	70th Percentile	90th Percentile

1. TSR is compared to total shareholder return of the companies included in the Edison Electric Institute (EEI) index of electric companies during the three-year measurement period; provided, however, a company in the EEI index that discloses in a filing made with the Securities and Exchange Commission that the company has entered into a definitive agreement to be acquired another company will be removed from the calculation effective as of the date of the announcement, unless the acquisition is rejected by the company's shareholders or applicable regulatory bodies before the end of the performance period.

TSR shall be determined by the following formula:

Total Shareholder Return = Ending Stock Price minus Beginning Stock Price plus Dividends Paid, divided by Beginning Stock Price.

Beginning Stock Price shall mean the average closing price on the applicable stock exchange of one share of stock during the most recent December prior to the Grant Date.

Ending Stock Price shall mean the average closing price on the applicable stock exchange of one share of stock during the most recent December prior to the Vesting Date.

Dividends Paid shall mean the sum of all dividends paid, based on the ex-dividend date, on one share of stock during the performance period.

At the end of the performance period, the Company will assess its TSR relative to all other companies remaining in the EEI index. If at least the Threshold Percentile noted above is achieved, depending on the Company's percentile rank and subject to the terms of the Agreement, the Grantee will receive the applicable percentage of the RSUs. If at least the Threshold Percentile noted above is achieved, interpolation will be used to determine payouts if percentile rank of relative TSR falls between the percentile ranks shown.

Cap on Negative TSR: If actual TSR performance is negative, payout for the portion of the award based on relative TSR is capped at Target (100%).

APPENDIX B

January 1, 2026 – December 31, 2028 Performance Criteria

Cumulative Adjusted EPS: Forty-two and nine-tenths percent (42.9%) of the target RSUs subject to this Agreement shall become vested based upon the Company's cumulative adjusted earnings per share from January 1, 2026 to December 31, 2028, calculated in the following manner:

Objective	Threshold (30%)	Target (100%)	Stretch (150%)	Superior (200%)
Cumulative Adjusted Earnings Per Share[2] (Interpolation applicable)	$13.23	$13.75	$13.88	$14.02

2. Cumulative Adjusted Earnings Per Share will be based on, and calculated in the same manner as the Company calculates and publicly discloses adjusted earnings per share; provided, however, that the Committee shall have the authority and discretion to calculate and adjust the Cumulative Adjusted Earnings Per Share and the extent to which this criterion has been satisfied.

EVERGY, INC.
2026 RESTRICTED STOCK UNIT AGREEMENT
(PERFORMANCE-BASED VESTING - ALTERNATE)

Grantor:	Evergy, Inc. or the Company
Grantee:	
Grant Date:	
Target Award of Restricted Stock Units (RSUs):	

THIS RESTRICTED STOCK UNIT AGREEMENT (the "Agreement") is entered into as of the Grant Date, by and between the Company and the Grantee with respect to the Target Award of RSUs granted herein, as such terms are defined in the chart above. All capitalized terms in this Agreement that are not defined herein shall have the meanings ascribed to such terms in the Company's Long-Term Incentive Plan, as amended and restated from time to time (the "Plan").

WHEREAS, Grantee is employed by the Company or one of its Subsidiaries and the Company desires to (i) encourage Grantee to acquire an interest in the growth and performance of the Company, (ii) provide Grantee with an incentive to enhance the value of the Company for the benefit of its customers and shareholders and (iii) encourage Grantee to remain in the employ of the Company as one of the key employees upon whom the Company's success depends; and

WHEREAS, the Company wishes to grant to Grantee, and Grantee wishes to accept, an Award of Restricted Stock Units, pursuant to the terms and conditions of the Plan and this Agreement.

NOW, THEREFORE, in consideration of the covenants and agreements herein contained, the parties agree as follows:

1. Restricted Stock Unit Award. The Company hereby grants to Grantee a target Award of Restricted Stock Units ("RSUs") defined in the chart above. Each RSU represents the right to receive one Share, subject to the terms and conditions set forth in this Agreement and the Plan, the terms and conditions of which are incorporated herein by reference.

2. Terms and Conditions. In addition to the terms and conditions in the Plan, this Award of RSUs is subject to the following terms and conditions:

   a. Grant of RSUs. The RSUs granted hereunder shall be credited to Grantee's RSU Account as of the Grant Date. The RSU Account shall be maintained for recordkeeping purposes only and the Company shall not be obligated to segregate or set aside assets representing securities or other amounts credited to Grantee's RSU Account. All amounts credited to the RSU Account shall continue for all purposes to be part of the general assets of the Company.

   b. Vesting of RSUs. The RSUs will vest on the later of (i) the third anniversary of the Grant Date and (ii) the date on which the Company files audited financial statements

with the Securities and Exchange Commission that include all performance periods set forth in Appendices A-C (the "Vesting Date"), provided that Grantee remains continuously employed by the Company or one of its Subsidiaries (except as provided in paragraph 2.c and 2.d of this Agreement) during the entire period that begins on the Grant Date and ends on the Vesting Date (the "Restricted Period"). The number of RSUs that vest on the Vesting Date will be determined in the manner described in Appendices A-C.

c. Termination of Employment during the Restricted Period for Death or Disability. If Grantee experiences a termination of employment on account of Grantee's death or Disability before the end of the Restricted Period, then as of the date of Grantee's termination of employment, that number of RSUs (and Dividend Equivalents) which would have vested if the target level of goal achievement for the Restricted Period had been met shall vest.

d. Termination of Employment during the Restricted Period for Retirement or Extended Retirement. If Grantee experiences a termination of employment on account of Retirement or Extended Retirement (each as defined below) before the end of the Restricted Period, Grantee shall receive the vesting benefits described in Sections 2(d)(i) or 2(d)(ii) below, as applicable. In all cases, settlement of any vested RSUs (and Dividend Equivalents) shall occur on the originally scheduled Vesting Date, with no acceleration of payment.

(i) Pro Rata Vesting (Retirement).

If the Grantee's termination of employment qualifies as a Retirement, no RSUs shall immediately settle upon termination. Following the end of the Restricted Period, a pro rata portion of the RSUs (and Dividend Equivalents) that would have vested had the Grantee remained employed through the Vesting Date, based on actual performance results, shall vest and be settled on the Vesting Date.

The pro rata portion shall be determined by multiplying: (A) the number of RSUs that would have vested on the Vesting Date absent termination by (B) a fraction, the numerator of which is the number of days from the Grant Date through the date of Retirement, and the denominator of which is the number of days from the Grant Date through the Vesting Date.

Definition of Retirement.

For purposes of Section 2(d)(i), "Retirement" means the Grantee's separation from service: on or after attaining age sixty (60); after completing at least five (5) years of service with the Company or its Subsidiaries; and after providing the Company with at least six (6) months' advance written notice of the Grantee's Retirement

(ii) Full Vesting (Extended Retirement).

If the Grantee's termination of employment qualifies as an Extended Retirement, no RSUs shall immediately settle upon termination. Following the end of the Restricted Period, all RSUs (and Dividend Equivalents) shall vest based on actual performance

results and shall be settled on the Vesting Date, subject to satisfaction of the conditions for Extended Retirement.

Definition of Extended Retirement.

For purposes of Section 2(d)(ii), "Extended Retirement" means the Grantee's separation from service only if all of the following conditions are satisfied:

A. The Grantee has attained age sixty-two (62) and completed at least five (5) years of service with the Company or its Subsidiaries;

B. The Grantee has provided the required advance written notice as follows:

For Named Executive Officers ("NEOs") and Section 16 officers, notice determined to be reasonable by the Compensation & Leadership Development Committee ("CLD Committee");

For all other Grantees, at least six (6) months' advance written notice of Extended Retirement;

C. At least one (1) year has elapsed from the Grant Date to the date of separation from service; provided, however, that RSUs granted less than one year prior to separation shall vest pro rata in accordance with Section 2(d)(i);

D. The Grantee has submitted a transition plan approved as follows:

For the Chief Executive Officer ("CEO"): by the Board; For Section 16 Officers (other than the CEO): by the CLD Committee; For all other officers: by the CEO; For non-officer Grantees: by an officer; and

E. For any Grantee who is an NEO or a Section 16 Officer, the CLD Committee has approved, in its sole discretion, the Grantee's eligibility for Extended Retirement.

Additional Condition.

Notwithstanding the foregoing, a Grantee shall not be eligible for Extended Retirement unless, if requested by the Company, the Grantee timely executes—and does not revoke within any applicable revocation period—a restrictive covenant and release of claims agreement, in a form provided by the Company, including confidentiality, release of claims, non-solicitation, non-competition, and non-disparagement provisions.

e. Limits on Transfer of RSUs. Subject to any exceptions set forth in the Plan, during the Restricted Period and until such time as the RSUs are settled in accordance with the terms of this Agreement, neither the RSUs nor any rights relating thereto may be assigned, alienated, pledged, attached, sold or otherwise transferred or encumbered by Grantee. Any attempt to assign, alienate, pledge, attach, sell or otherwise transfer or encumber the RSUs or the rights relating thereto shall be wholly ineffective and, if

any such attempt is made, the RSUs will be immediately forfeited by Grantee and all of Grantee's rights to the RSUs shall immediately terminate without any payment, settlement, or consideration by the Company.

f. No Rights as a Shareholder until RSUs Settled. Grantee shall not have any rights of a shareholder with respect to the Shares underlying the RSUs unless and until the RSUs vest and are settled by the issuance of Shares.

g. Dividend Equivalents. Each RSU that becomes vested pursuant to this Agreement includes the right to receive dividend equivalents in an amount equal to the amount of the cash dividends that Grantee would have received if Grantee owned that number Shares represented by the vested RSUs during the Restricted Period and before the RSUs were settled. These dividend equivalents, if any, shall be accrued and paid to Grantee in cash, less taxes, at the time the RSUs are settled in accordance with paragraph 2.h. below. If, during the Restricted Period, the Company declares a stock dividend on Shares, then the Grantee may be eligible for additional Shares at the time the RSUs are settled in accordance with paragraph 2.h. below (or earlier as determined by the Committee) based on the number of RSUs credited to the Grantee's RSU Account in accordance with Section 16.H of the Plan.

When the Vesting Date falls between a dividend record date and the dividend payment date, the additional number of RSUs (including fractional RSUs), which shall be credited to the RSU account as dividend equivalents will be calculated as set forth above, except that the share price will be calculated based on the date immediately preceding the dividend *record* date instead of the date immediately preceding the dividend *payment* date, and the resulting Shares are issued concurrently with the other Shares vesting on the Vesting Date.

h. Settlement of RSUs. No later than 30 days after the earlier of (i) the Vesting Date or (ii) Grantee's termination of employment due to death or Disability, the Company shall issue and deliver to Grantee, or in the event of Grantee's death the beneficiary designated in writing by Grantee in accordance with instructions provided by the Company (or in the event Grantee has not designated a beneficiary, Grantee's estate), a number of Shares equal to the aggregate number of vested RSUs (with any fractional Share underlying the vested RSUs on the settlement date being settled by delivering to Grantee a cash payment equal to the closing price of a Share on the Vesting Date or the date of Grantee's termination of employment, as applicable, multiplied by the number of fractional vested RSUs) then credited to Grantee's RSU Account. The Committee may, in its sole discretion, settle any vested RSUs by delivering to Grantee (or Grantee's beneficiary or estate in the event of Grantee's death) an amount of cash equal to the closing price of a Share on the Vesting Date or the date of Grantee's termination of employment, as applicable, multiplied by the number of vested RSUs (and any fraction thereof) held by Grantee.

i. Tax Withholding on RSU Settlement. No Shares will be delivered under this Agreement until either (i) Grantee has paid to the Company the amount that must be withheld under federal, state and local income and employment tax laws or (ii) Grantee and the Company have made satisfactory provision for the payment of such taxes.

Unless otherwise not permitted by the Committee (which may disallow Share withholding at any time) or contrary to an election Grantee submitted to the Company in accordance with established Company policy, the Company shall first withhold such taxes from the Shares (valued at their Fair Market Value) otherwise eligible to be delivered under this Award, if any.

j. 280G Best Net. Notwithstanding anything in this Agreement to the contrary, in the event that (A) there is a Change in Control, and (B) the receipt of all payments, distributions or benefits (including, without limitation, accelerated vesting of the RSUs) by the Company in the nature of compensation to or for Grantee's benefit, whether paid or payable pursuant to this Agreement or otherwise (a "Payment"), would subject Grantee to the excise tax under Section 4999 of the Code by virtue of Section 280G of the Code, the Company shall reduce the number of RSUs which become vested on account of the Change in Control if such reduction would result in Grantee having a greater net after-tax Payment than if such RSUs were not reduced and the Payment, or any portion thereof, is subjected to the excise tax under Section 4999 of the Code.

k. Clawback. This Award will be subject to certain provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 ("Dodd-Frank") and any other compensation clawback or recoupment policy that the Committee has adopted or is required to adopt pursuant to the listing standards of any national securities exchange on which the Company's securities are listed or as is otherwise required by Dodd Frank or any other applicable law. Grantee acknowledges that the Award or any compensation derived therefrom may be forfeited and/or recouped by the Company in accordance with any policies and procedures adopted by the Committee in order to comply with Dodd Frank or other clawback or recoupment policy. Without limitation, the Company may, in its discretion, or shall as required by law, (i) seek repayment from the Grantee; (ii) reduce the amount that would otherwise be payable to the Grantee under current or future Awards; (iii) withhold future equity grants or salary increases; (iv) pursue other available legal remedies, or (v) any combination of these actions. The Company's clawback or recoupment policy may require the Company take such recoupment actions against the Grantee whether or not such Grantee engaged in any misconduct or was otherwise at fault with respect to any event or circumstance giving rise to such clawback action.

The Company will, to the full extent permitted by law, have the discretion based on the particular facts and circumstances to require that the Grantee reimburse the Company for all or any portion of any Awards if and to the extent the Awards reflected the achievement of financial results that were subsequently the subject of a restatement, or the achievement of other objectives that were subsequently found to be inaccurately measured, and a lower Award would have occurred based upon the restated financial results or accurately measured objectives. The Company may, in its discretion, (i) seek repayment from the Grantee; (ii) reduce the amount that would otherwise be payable to the Grantee under current or future Awards; (iii) withhold future equity grants or salary increases; (iv) pursue other available legal remedies or (v) any combination of these actions. The Company may take such actions against

any Grantee, whether or not such Grantee engaged in any misconduct or was otherwise at fault with respect to such restatement or inaccurate measurement.

3. Amendment. This Agreement may be amended only in the manner provided by the Company evidencing both parties' agreement to the amendment. This Agreement may also be amended, without prior notice to Grantee and without Grantee's consent before any Change in Control by the Committee if the Committee in good faith determines the amendment does not materially adversely affect any of Grantee's rights under this Agreement.

4. Entire Agreement. This Agreement contains the entire agreement between Grantee and the Company with respect to the subject matter hereof and supersedes all prior agreements or understandings between the parties relating thereto.

5. Miscellaneous. This Agreement may be executed in counterparts, each of which shall be deemed to be an original, and shall constitute the same Agreement. This Agreement shall become a binding agreement between Grantor and Grantee when a counterpart of this Agreement has been either (i) signed by each party, or (ii) accepted and acknowledged electronically by each party, or a combination thereof. An electronic signature of Grantor or Grantee on DocuSign or other signing platform, or a "box check" acceptance and acknowledgement on the E*TRADE or Morgan Stanley or other platform, transmitted electronically, shall be deemed to be original signatures of such parties for all purposes, shall constitute an intent to be bound by the terms and conditions of this Agreement, and effective execution and delivery of this Agreement.

[Signature Page Follows]

EVERGY, INC.

By: _____
Lesley L. Elwell
Senior Vice President, Chief People Officer

APPENDIX A

January 1, 2026 – December 31, 2028 Performance Criteria

Relative Total Shareholder Return: Fifty percent (57.1%) of the target RSUs subject to this Agreement shall become vested based upon the Company's relative total shareholder return from January 1, 2026 to December 31, 2028, calculated in the following manner:

Objective	(0%)	Threshold (25%)	Target (100%)	Stretch (150%)	Superior (200%)
Relative Total Shareholder Return (TSR) versus EEI Index[1] (Interpolation applicable)	< 25th Percentile	25th Percentile	50th Percentile	70th Percentile	90th Percentile

1. TSR is compared to total shareholder return of the companies included in the Edison Electric Institute (EEI) index of electric companies during the three-year measurement period; provided, however, a company in the EEI index that discloses in a filing made with the Securities and Exchange Commission that the company has entered into a definitive agreement to be acquired another company will be removed from the calculation effective as of the date of the announcement, unless the acquisition is rejected by the company's shareholders or applicable regulatory bodies before the end of the performance period.

TSR shall be determined by the following formula:

Total Shareholder Return = Ending Stock Price minus Beginning Stock Price plus Dividends Paid, divided by Beginning Stock Price.

Beginning Stock Price shall mean the average closing price on the applicable stock exchange of one share of stock during the most recent December prior to the Grant Date.

Ending Stock Price shall mean the average closing price on the applicable stock exchange of one share of stock during the most recent December prior to the Vesting Date.

Dividends Paid shall mean the sum of all dividends paid, based on the ex-dividend date, on one share of stock during the performance period.

At the end of the performance period, the Company will assess its TSR relative to all other companies remaining in the EEI index. If at least the Threshold Percentile noted above is achieved, depending on the Company's percentile rank and subject to the terms of the Agreement, the Grantee will receive the applicable percentage of the RSUs. If at least the Threshold Percentile noted above is achieved, interpolation will be used to determine payouts if percentile rank of relative TSR falls between the percentile ranks shown.

Cap on Negative TSR: If actual TSR performance is negative, payout for the portion of the award based on relative TSR is capped at Target (100%).

APPENDIX B

January 1, 2026 – December 31, 2028 Performance Criteria

Cumulative Adjusted EPS: Forty-two and nine-tenths percent (42.9%) of the target RSUs subject to this Agreement shall become vested based upon the Company's cumulative adjusted earnings per share from January 1, 2026 to December 31, 2028, calculated in the following manner:

Objective	Threshold (30%)	Target (100%)	Stretch (150%)	Superior (200%)
Cumulative Adjusted Earnings Per Share[2] (Interpolation applicable)	$13.23	$13.75	$13.88	$14.02

2. Cumulative Adjusted Earnings Per Share will be based on, and calculated in the same manner as the Company calculates and publicly discloses adjusted earnings per share; provided, however, that the Committee shall have the authority and discretion to calculate and adjust the Cumulative Adjusted Earnings Per Share and the extent to which this criterion has been satisfied.

Evergy, Inc.
Executive Annual Incentive Plan
(Effective as of January 1, 2026)

Objective

The Evergy, Inc. (the "Company" or "Evergy") Executive Annual Incentive Plan (the "Plan") is designed to motivate and reward officers of Evergy for the achievement of specific key financial, operational and business goals. By providing market-competitive target awards and additional award opportunities for extraordinary achievements and results, the Plan both supports the attraction and retention of senior executive talent critical to achieving the Company's strategic business objectives and provides financial incentives to reward key performers.

Eligibility

Eligible participants ("Participants") shall be the named executive officers ("NEOs") and non-NEOs of the Company as approved by the Compensation and Leadership Development Committee ("Committee") or Board of Directors (the "Board") of the Company.

Administration

The Committee and/or the Board has the full power and authority to (i) interpret the provisions of the Plan, (ii) determine the terms and conditions of any award, (iii) amend the terms or conditions of any award, (iv) determine whether, and to what extent, awards may become vested, paid (in full or in part), forfeited or suspended, (v) establish, amend, suspend or waive any payment conditions for an award or rules relating to the administration of the Plan, (vi) delegate all or part of its authority under the Plan to one or more directors and, with respect to the day-to-day administration and operations of the Plan (but not granting of awards or any determination of any amounts eligible to be paid under the Plan) to officers of the Company and (vii) make any other determination or take any action that is deemed necessary or desirable for the administration of the Plan or the payment of awards thereunder. All determinations and decisions made by the Committee pursuant to the provisions of the Plan shall be final, conclusive and binding on all persons, and shall be given maximum deference permitted by law.

Awards

Awards and award levels are developed and approved by the Committee, who may seek the input of the Company's management and outside consultants and advisors and may further seek approval by the full Board. Awards, which may vary based on the Participant's level of responsibility, market data, internal comparisons and other factors the Committee believes is appropriate, may be (i) established as a percentage of the Participant's base salary, (ii) established as an absolute amount or (iii) established based on any other factor or criteria.

Performance Period and Incentive Objectives

The Plan will be effective as of January 1, 2026 and end on December 31, 2026 (the "Performance Period") unless the Committee in its sole discretion desires to have a different Performance Period. The Committee will establish and approve, and if applicable, submit for approval by the Board, specific annual objectives and performance levels that are applicable to each Participant, which annual objectives and performance levels may be based on any performance goal or criteria the Committee believes is appropriate. The amount of a Participant's award will be determined in the Committee's discretion and may differ from Participant to Participant, based on performance against the specific objectives and performance levels approved by the Committee. The Committee may adjust or modify the established annual objectives or performance levels, or the determination of any performance goals or criteria, in its discretion at any time and for any reason.

Payment of Awards

Payment Timing. Except as otherwise set forth in this Plan, earned awards will generally be payable to each Participant after the completion of the Performance Period and as soon as administratively practicable following the determination by the Committee of the achievement level for the performance goal(s) and each of the relevant objectives relating thereto. The awards will be paid, in the sole discretion of the Committee, in cash, Company stock (in the form of "Bonus Shares" as defined and under the Company's Long-Term Incentive Plan ("LTIP"), as may be amended or restated), or a combination of cash and stock, except to the extent receipt of payment is properly deferred under the Company's Nonqualified Deferred Compensation Plan (the "NQDC Plan"). Any earned award for which a deferral election has been made under the NQDC Plan will result in a cash award being deferred, as Bonus Shares are not eligible to be deferred under such plan. Except to the extent deferred under the NQDC Plan, in no event shall payment be made later than the 15th day of the third month following the end of the taxable year in which the Committee's determination of award achievement is made.

Continuous Employment Required. Except as set forth below, or as otherwise provided for in the Company's executive severance plan or in any change-in-control severance agreement between the Participant and the Company, a Participant must be employed by the Company or one of its subsidiaries at the time of payment under this Plan to be entitled to payment of an award, if any.

Miscellaneous

Extraordinary Employment Situations.

Employment after Commencement of Performance Period. An award for a person who becomes a Participant during a Performance Period will be prorated unless otherwise determined by the Committee.

Termination of Employment during the Performance Period for Death or Disability. If a Participant experiences a termination of employment on account of the Participant's death or Disability, as defined in the Company's Long-Term Disability Plan, before the end of the Performance Period, then, as of the date of the Participant's termination of employment, the Participant (or, in the case of death, the Participant's estate) will be entitled to a pro rata portion of the target award for the fiscal year in which the termination of employment occurs. The pro rata portion of the Participant's target award shall be determined by multiplying the target award for the year in which the termination of employment occurs by a fraction, the numerator of which is the number of calendar days elapsed in the Performance Period through the date on which termination of employment occurs and the denominator of which is 365. Awards that vest in connection with termination of employment on account of death or Disability, as set forth in this section of the Plan, will be paid in cash in a lump sum as soon as administratively practicable, but in no event later than 30 days after the Participant's death or a determination that the Participant has a Disability, as applicable.

Termination of Employment during the Performance Period for Retirement. If a Participant experiences a termination of employment on account of the Participant's Retirement (as defined below) before the end of the Performance Period, no immediate vesting shall occur at the time of the Participant's Retirement but, following the end of the Performance Period, a pro rata portion of the award shall vest. The pro rata portion of the Participant's target award shall be determined by multiplying the actual award based on the achieved level of performance for the year in which Retirement occurs by a fraction, the numerator of which is the number of calendar days elapsed in the Performance Period through the date on which the Retirement occurs for such year and the denominator of which is 365. The term "Retirement" means a Participant has attained the age of fifty-five (55) and has at least five (5) years of service with the Company.

Unfunded Benefits. No benefit provided under this Plan is subject to the Employee Retirement Income Security Act of 1974, as amended, and all benefits under the Plan are unfunded. No Participant shall have any greater right than the right of a general unsecured creditor of the Company.

Amendments and Termination. The Board or the Committee has the exclusive right to terminate, modify, change or alter the Plan at any time.

Clawback or Recoupment. The award will be subject to certain provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 ("Dodd-Frank") and any other compensation clawback or recoupment policy that the Committee has adopted or is required to adopt pursuant to the listing standards of any national securities exchange on which the Company's securities are listed or as is otherwise required by Dodd Frank or any other applicable law. Participant acknowledges that the award or any compensation derived therefrom may be forfeited and/or recouped by the Company in accordance with any policies and procedures adopted by the Committee in order to comply with Dodd Frank or other clawback or recoupment policy. Without limitation, the Company may, in its discretion, or shall as required by law, (i) seek repayment from the Participant; (ii) reduce the amount that would otherwise be payable to the Participant under current or future awards; (iii) withhold future equity grants or salary increases; (iv) pursue other available legal remedies, or (v) any combination of these actions. The Company's clawback or recoupment policy may require the Company take such recoupment actions against the Participant whether or not such Participant engaged in any misconduct or was otherwise at fault with respect to any event or circumstance giving rise to such clawback action.

The Company will, to the full extent permitted by law, have the discretion based on the particular facts and circumstances to require that the Grantee reimburse the Company for all or any portion of any Awards if and to the extent the Awards reflected the achievement of financial results that were subsequently the subject of a restatement, or the achievement of other objectives that were subsequently found to be inaccurately measured, and a lower Award would have occurred based upon the restated financial results or accurately measured objectives. The Company may, in its discretion, (i) seek repayment from the Grantee; (ii) reduce the amount that would otherwise be payable to the Grantee under current or future Awards; (iii) withhold future equity grants or salary increases; (iv) pursue other available legal remedies or (v) any combination of these actions. The Company may take such actions against any Grantee, whether or not such Grantee engaged in any misconduct or was otherwise at fault with respect to such restatement or inaccurate measurement.

Tax Withholding. Any payment or benefit under the Plan is subject to all applicable withholding and other taxes applicable to the entire award, which must be satisfied by the Participant in a manner satisfactory to the Company and in accordance with applicable law before any payment is made under this Plan.

Code Section 409A. It is intended that the payments under the Plan qualify as short-term deferrals exempt from the requirements of Section 409A of the Internal Revenue Code of 1986, as amended ("Section 409A"). In the event that any award does not qualify for treatment as an exempt short-term deferral, it is intended that such amount will be paid in a manner that satisfies the requirements of Section 409A. The Plan shall be interpreted and construed accordingly.

Adopted on February 17, 2026.

By: /s/ Sandra Lawrence
Chair, Compensation and Leadership Development Committee

Exhibit A

2026 Annual Incentive Plan – 2026 Performance Objectives

Officer Annual Incentive Plan (AIP) Scorecard - 2026								
OBJECTIVE			MEASURE	AIP Weight	Targets			
					Threshold (50%)	Target (100%)	Stretch (150%)	Superior 200%
1.	SAFETY	1.1	**Weighted Basket of Measures:**	12.5%				
			- DART Rate (70%)		1.05	**0.70**	0.54	0.37
			- Percent of Potential Severe Injury or Fatality (PSIF) Incidents Investigated With Plans on Track (30%)		90%	**100%**	N/A	N/A
					Safety payout reduced by 50% of performance in the event of a fatality			
2.	OPERATIONS	2.1	**SAIDI (minutes interrupted per customer)**	7.5%	103	**96**	92	88
		2.2	**Seasonal Equivalent Forced Outage Rate (EFOR'd)**	7.5%				
			- Summer (June 1 - September 30)		10.3%	**8.3%**	7.3%	6.3%
			- Winter (January 1 - March 31, December 1 - December 31)		12.7%	**10.7%**	9.7%	8.7%
3.	CUSTOMER EXPERIENCE	3.1	**Weighted Basket of Measures:**	7.5%				
			- Customer Experience Surveys (Call Center, IVA, and Website) (50%)		3.58	**3.68**	3.73	3.78
			- Business Customer Satisfaction Surveys (Top Three Box Score) (50%)		90.5%	**93.9%**	95.5%	97.0%
4.	FINANCIAL	4.1	**Adjusted Earnings per Share**	42.5%	*	*	*	*
		4.2	**Adjusted NFOM ($ in millions)**	22.5%	*	*	*	*
				100.0%	Total weighting			

evergy

Evergy, Inc.

Summary of
Non-Employee Director Compensation (2025)

Effective May 7, 2025

	Amount
Cash Compensation (Paid Quarterly)	
Annual	$120,000
Lead Director	$30,000
Audit Committee Chair	$20,000
Compensation and Leadership Development Committee Chair	$20,000
Nominating, Governance, and Corporate Responsibility Committee Chair	$20,000
Finance Committee Chair	$20,000
Nuclear and Operations Committee Co-Chairs (each)	$20,000
Per Meeting Fees	None
Company Common Stock (Paid Annually Following Shareholder Meeting)	
Annual Equity Compensation	$160,000

All members of the Board of Directors are entitled to be reimbursed for expenses, as set forth in Evergy, Inc.'s corporate governance guidelines. Evergy, Inc. also provides liability insurance to its directors under its directors and officers insurance policies.

Subsidiaries of Evergy, Inc. [1]

Name of Company	State of Incorporation
Evergy Metro, Inc.	Missouri
Evergy Missouri West, Inc.	Delaware
Evergy Kansas Central, Inc.	Kansas
Evergy Kansas South, Inc. [2]	Kansas

[1] Certain subsidiaries of Evergy, Inc. have been omitted pursuant to Item 601(b)(21)(ii) of Regulation S-K.
[2] Evergy Kansas South, Inc. is a subsidiary of Evergy Kansas Central, Inc.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-281614, 333-278398 and 333-282613 on Form S-3 and Registration Statement Nos. 333-225673, 333-254552 (including Post-effective Amendment No. 1 thereto) and 333-264802 on Form S-8 of our reports dated February 18, 2026, relating to the financial statements of Evergy, Inc., and the effectiveness of Evergy, Inc. internal control over financial reporting appearing in this Annual Report on Form 10-K for the year ended December 31, 2025.

/s/ DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 18, 2026

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-281614-01 on Form S-3 of our report dated February 18, 2026, relating to the financial statements of Evergy Metro, Inc., appearing in this Annual Report on Form 10-K for the year ended December 31, 2025.

/s/ DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 18, 2026

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-281614-02 on Form S-3 of our report dated February 18, 2026, relating to the financial statements of Evergy Kansas Central, Inc., appearing in this Annual Report on Form 10-K for the year ended December 31, 2025.

/s/ DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 18, 2026

Power of Attorney

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below, each of whom is a member of the Board of Directors of Evergy, Inc., a Missouri corporation, constitutes and appoints David A. Campbell, W. Bryan Buckler, and Matthew B. Gummig, and Heather A. Humphrey, and each of them, his or her true and lawful attorneys-in-fact and agents, each acting alone, with full power of substitution and re-substitution, to execute in the name and on behalf of the undersigned as such director an Annual Report on Form 10-K, and any amendments thereto, granting unto said attorneys-in-fact and agents and each of them, full power and authority to do and to perform each and every act and thing necessary or desirable to be done in and about the premises in order to effectuate the same as fully to all intents and purposes as he or she might or could do if personally present, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have hereunto set their hands this 18th day of February, 2026.

/s/ David A. Campbell
David A. Campbell

/s/ B. Anthony Isaac
B. Anthony Isaac

/s/ Paul M. Keglevic
Dean Newton

/s/ Mary L. Landrieu
Mary L. Landrieu

/s/ Sandra A.J. Lawrence
Sandra A.J. Lawrence

/s/ Ann D. Murtlow
Ann D. Murtlow

/s/ Dean A. Newton
Dean A. Newton

/s/ Sandra J. Price
Sandra J. Price

/s/ Jonathan D. Rolph
Jonathan D. Rolph

/s/ James Scarola
James Scarola

/s/ Neal A. Sharma
Neal A. Sharma

/s/ C. John Wilder
C. John Wilder

Power of Attorney

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below, each of whom is a member of the Board of Directors of Evergy Kansas Central, Inc., a Kansas corporation, constitutes and appoints David A. Campbell, W. Bryan Buckler, and Matthew B. Gummig, and Heather A. Humphrey, and each of them, his or her true and lawful attorneys-in-fact and agents, each acting alone, with full power of substitution and re-substitution, to execute in the name and on behalf of the undersigned as such director an Annual Report on Form 10-K, and any amendments thereto, granting unto said attorneys-in-fact and agents and each of them, full power and authority to do and to perform each and every act and thing necessary or desirable to be done in and about the premises in order to effectuate the same as fully to all intents and purposes as he or she might or could do if personally present, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have hereunto set their hands this 18th day of February, 2026.

/s/ David A. Campbell
David A. Campbell

/s/ B. Anthony Isaac
B. Anthony Isaac

/s/ Paul M. Keglevic
Dean Newton

/s/ Mary L. Landrieu
Mary L. Landrieu

/s/ Sandra A.J. Lawrence
Sandra A.J. Lawrence

/s/ Ann D. Murtlow
Ann D. Murtlow

/s/ Dean A. Newton
Dean A. Newton

/s/ Sandra J. Price
Sandra J. Price

/s/ Jonathan D. Rolph
Jonathan D. Rolph

/s/ James Scarola
James Scarola

/s/ Neal A. Sharma
Neal A. Sharma

/s/ C. John Wilder
C. John Wilder

Power of Attorney

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below, each of whom is a member of the Board of Directors of Evergy Metro, Inc., a Missouri corporation, constitutes and appoints David A. Campbell, W. Bryan Buckler, and Matthew B. Gummig, and Heather A. Humphrey, and each of them, his or her true and lawful attorneys-in-fact and agents, each acting alone, with full power of substitution and re-substitution, to execute in the name and on behalf of the undersigned as such director an Annual Report on Form 10-K, and any amendments thereto, granting unto said attorneys-in-fact and agents and each of them, full power and authority to do and to perform each and every act and thing necessary or desirable to be done in and about the premises in order to effectuate the same as fully to all intents and purposes as he or she might or could do if personally present, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have hereunto set their hands this 18th day of February, 2026.

/s/ David A. Campbell
David A. Campbell

/s/ B. Anthony Isaac
B. Anthony Isaac

/s/ Paul M. Keglevic
Dean Newton

/s/ Mary L. Landrieu
Mary L. Landrieu

/s/ Sandra A.J. Lawrence
Sandra A.J. Lawrence

/s/ Ann D. Murtlow
Ann D. Murtlow

/s/ Dean A. Newton
Dean A. Newton

/s/ Sandra J. Price
Sandra J. Price

/s/ Jonathan D. Rolph
Jonathan D. Rolph

/s/ James Scarola
James Scarola

/s/ Neal A. Sharma
Neal A. Sharma

/s/ C. John Wilder
C. John Wilder

Exhibit 31.1

CERTIFICATIONS

I, David A. Campbell, certify that:

1. I have reviewed this Annual Report on Form 10-K of Evergy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2026

/s/ David A. Campbell
David A. Campbell
Chairman, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATIONS

I, W. Bryan Buckler, certify that:

1. I have reviewed this Annual Report on Form 10-K of Evergy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2026

/s/ W. Bryan Buckler
W. Bryan Buckler
Executive Vice President and Chief Financial Officer

Exhibit 31.3

CERTIFICATIONS

I, David A. Campbell, certify that:

1. I have reviewed this Annual Report on Form 10-K of Evergy Metro, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2026

/s/ David A. Campbell
David A. Campbell
Chairman, President and Chief Executive Officer

Exhibit 31.4

CERTIFICATIONS

I, W. Bryan Buckler, certify that:

1. I have reviewed this Annual Report on Form 10-K of Evergy Metro, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2026

/s/ W. Bryan Buckler
W. Bryan Buckler
Executive Vice President and Chief Financial Officer

Exhibit 31.5

CERTIFICATIONS

I, David A. Campbell, certify that:

1. I have reviewed this Annual Report on Form 10-K of Evergy Kansas Central, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2026

/s/ David A. Campbell
David A. Campbell
Chairman, President and Chief Executive Officer

Exhibit 31.6

CERTIFICATIONS

I, W. Bryan Buckler, certify that:

1. I have reviewed this Annual Report on Form 10-K of Evergy Kansas Central, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2026

/s/ W. Bryan Buckler
W. Bryan Buckler
Executive Vice President and Chief Financial Officer

Exhibit 32.1

Certification of CEO and CFO Pursuant to
18 U.S.C. Section 1350,
as Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report on Form 10-K of Evergy, Inc. (the "Company") for the annual period ended December 31, 2025, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), David A. Campbell, as Chairman, President and Chief Executive Officer of the Company, and W. Bryan Buckler, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ David A. Campbell
Name: David A. Campbell
Title: Chairman, President and Chief Executive Officer
Date: February 18, 2026

/s/ W. Bryan Buckler
Name: W. Bryan Buckler
Title: Executive Vice President and Chief Financial Officer
Date: February 18, 2026

Exhibit 32.2

Certification of CEO and CFO Pursuant to
18 U.S.C. Section 1350,
as Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report on Form 10-K of Evergy Metro, Inc. (the "Company") for the annual period ended December 31, 2025, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), David A. Campbell, as Chairman, President and Chief Executive Officer of the Company, and W. Bryan Buckler, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ David A. Campbell
Name: David A. Campbell
Title: Chairman, President and Chief Executive Officer
Date: February 18, 2026

/s/ W. Bryan Buckler
Name: W. Bryan Buckler
Title: Executive Vice President and Chief Financial Officer
Date: February 18, 2026

Exhibit 32.3

Certification of CEO and CFO Pursuant to
18 U.S.C. Section 1350,
as Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report on Form 10-K of Evergy Kansas Central, Inc. (the "Company") for the annual period ended December 31, 2025, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), David A. Campbell, as Chairman, President and Chief Executive Officer of the Company, and W. Bryan Buckler, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ David A. Campbell
Name: David A. Campbell
Title: Chairman, President and Chief Executive Officer
Date: February 18, 2026

/s/ W. Bryan Buckler
Name: W. Bryan Buckler
Title: Executive Vice President and Chief Financial Officer
Date: February 18, 2026

APPENDIX 8

VERIFICATION

I, Evan K. Dean, Managing Director, Transmission Joint Ventures Governance and Operations, hereby state that the facts set forth above are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Date: May 21, 2026

By: _____

Evan K. Dean, Managing Director
Transmission Joint Ventures Governance
and Operations

BEFORE THE
PENNSYLVANIA PUBLIC UTILTIY COMMISSION

Application of Transource Pennsylvania, LLC for All of the Necessary Authority, Approvals and Certificate of Public Convenience to Begin to Offer, Render, Furnish and/or Supply Transmission Service in portions of Franklin County, Pennsylvania Necessary to Operate Transmission Facilities for Project 9A West; and for any Other Approvals Necessary	:	Docket No. A-2026-_____

CERTIFICATE OF SERVICE

I hereby certify and affirm that I have this day served a copy of the Application of Transource Pennsylvania, LLC for All of the Necessary Authority, Approvals and Certificate of Public Convenience to Begin to Offer, Render, Furnish and/or Supply Transmission Service in portions of Franklin County, Pennsylvania Necessary to Operate Transmission Facilities for Project 9A West; and for any Other Approvals Necessary on the following persons in the manner specified in accordance with the requirements of 52 Pa. Code §1.54:

Via Certified Mail, Return Receipt Requested:

Pennsylvania Bureau of Investigation
and Enforcement
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
2nd Floor, Room-N201
Harrisburg, Pennsylvania 17120
Attn: Allison Kaster

Pennsylvania Office of Small
Business Advocate
555 Walnut Street, 1st Floor Forum Place
Harrisburg, Pennsylvania 17101
Attn: NazArah Sabree

Pennsylvania Office of Consumer Advocate
555 Walnut Street 5th Floor Forum Place
Harrisburg, Pennsylvania 17101-1923
Attn: Darryl A. Lawrence, Consumer
Advocate

Date: May 21, 2026

John F. Povilaitis
Buchanan Ingersoll & Rooney PC
400 North 2nd Street
Harrisburg, PA 17101
(717) 237-4825
John.povilaitis@bipc.com