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	Exact name of registrant as specified in its charter; State or other jurisdiction of incorporation or organization; Address of principal executive offices, including zip code; and Registrant's telephone number, including area code	IRS Employer Identification No.
1-8962	**PINNACLE WEST CAPITAL CORPORATION** (an Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix Arizona 85072-3999 (602) 250-1000	86-0512431
1-4473	**ARIZONA PUBLIC SERVICE COMPANY** (an Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix Arizona 85072-3999 (602) 250-1000	86-0011170

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

	Title Of Each Class	Trading Symbol (s)	Name Of Each Exchange On Which Registered
PINNACLE WEST CAPITAL CORPORATION	Common Stock, No Par Value	PNW	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
ARIZONA PUBLIC SERVICE COMPANY Common Stock, Par Value $2.50 per share

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act

PINNACLE WEST CAPITAL CORPORATION	Yes ☒	No ☐
ARIZONA PUBLIC SERVICE COMPANY	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.

PINNACLE WEST CAPITAL CORPORATION	Yes ☐	No ☒
ARIZONA PUBLIC SERVICE COMPANY	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.

PINNACLE WEST CAPITAL CORPORATION	Yes ☒	No ☐
ARIZONA PUBLIC SERVICE COMPANY	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 during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

PINNACLE WEST CAPITAL CORPORATION	Yes	☒	No	☐
ARIZONA PUBLIC SERVICE COMPANY	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.

PINNACLE WEST CAPITAL CORPORATION

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

ARIZONA PUBLIC SERVICE COMPANY

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. ☐

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 each registrant is a shell company (as defined in Rule 12b-2 of the Act).

PINNACLE WEST CAPITAL CORPORATION	Yes	☐	No	☒
ARIZONA PUBLIC SERVICE COMPANY	Yes	☐	No	☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates, computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of each registrant’s most recently completed second fiscal quarter:

PINNACLE WEST CAPITAL CORPORATION	$	10,673,413,436	as of June 30, 2025
ARIZONA PUBLIC SERVICE COMPANY	$	0	as of June 30, 2025

Indicate the number of shares outstanding of each of the issuer’s classes of common stock, as of the latest practicable date.

PINNACLE WEST CAPITAL CORPORATION	Number of shares of common stock, no par value, outstanding as of February 19, 2026:	120,905,390
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of February 19, 2026:	71,264,947

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Pinnacle West Capital Corporation’s definitive Proxy Statement relating to its Annual Meeting of Shareholders to be held on May 14, 2026 are incorporated by reference into Part III hereof.

Arizona Public Service Company meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format allowed under General Instruction I(2).

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This combined Form 10-K is separately filed by Pinnacle West Capital Corporation ("Pinnacle West") and Arizona Public Service Company ("APS"). Any use of the words "Company," "we," "us," and "our" refer to Pinnacle West unless the context otherwise requires. Each registrant is filing on its own behalf all of the information contained in this Form 10-K that relates to such registrant and, where required, its subsidiaries. Except as stated in the preceding sentence, neither registrant is filing any information that does not relate to such registrant, and therefore makes no representation as to any such information. The information required with respect to each company is set forth within the applicable items. Item 8 of this report includes Consolidated Financial Statements of Pinnacle West and Consolidated Financial Statements of APS. Part II, Item 8 also includes Combined Notes to Consolidated Financial Statements.

GLOSSARY OF NAMES AND TECHNICAL TERMS

ACC	Arizona Corporation Commission
ADEQ	Arizona Department of Environmental Quality
AFUDC	Allowance for funds used during construction
AI	Artificial intelligence
ANPP	Arizona Nuclear Power Project, also known as Palo Verde
APS	Arizona Public Service Company, a subsidiary of the Company
ARO	Asset retirement obligations
ASRFP	All-source request for proposal
ASU	Accounting Standards Update
ATM Program	At-the-market equity distribution program
Base Fuel Rate	The portion of APS’s retail base rates attributable to fuel and purchased power costs
BCE	Bright Canyon Energy Corporation
BESS	Battery energy storage system
CAISO	California Independent System Operator
Captive	Captive Insurance Cell
CCR	Coal combustion residuals
CCRMU	Coal combustion residuals management unit
CCS	Carbon capture and sequestration or utilization controls
CERCLA or Superfund	Comprehensive Environmental Response Compensation and Liability Act
Cholla	Cholla Power Plant
DG	Distributed Generation
DOE	United States Department of Energy
DSM	Demand Side Management
EES	Energy Efficiency Standard
El Dorado	El Dorado Investment Company, a subsidiary of the Company
ELG	Effluent Limitation Guidelines
EPA	United States Environmental Protection Agency
FERC	United States Federal Energy Regulatory Commission
Four Corners	Four Corners Power Plant
FRAM	Formula Rate Adjustment Mechanism
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
GWh	Gigawatt-hour, one billion watts per hour
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
kV	Kilovolt, one thousand volts
kWh	Kilowatt-hour, one thousand watts per hour
LFCR	Lost Fixed Cost Recovery Mechanism
MW	Megawatt, one million watts
MWh	Megawatt-hour, one million watts per hour
NAAQS	National Ambient Air Quality Standards
Native Load	Retail and wholesale sales supplied under traditional cost-based rate regulation
Navajo Plant	Navajo Generating Station
NERC	North American Electric Reliability Corporation
NPDES	National Pollutant Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NTEC	Navajo Transitional Energy Company, LLC
NEIL	Nuclear Electric Insurance Limited
Ocotillo	Ocotillo Power Plant
Palo Verde	Palo Verde Generating Station or PVGS
PFAS	Per- and polyfluoroalkyl compounds
Pinnacle West	Pinnacle West Capital Corporation (any use of the words “Company,” “we,” “us,” and “our” refer to Pinnacle West unless the context requires otherwise)

PNW Power	Pinnacle West Power, LLC, a subsidiary of the Company
PPA	Power purchase agreement
PSA	Power Supply Adjustor
PTC	Production tax credit
RCRA	Resource Conservation and Recovery Act
Redhawk	Redhawk Power Plant
RES	Renewable Energy Standard
ROD	Record of Decision
ROO	Recommended Opinion and Order
Salt River Project or SRP	Salt River Project Agricultural Improvement and Power District
SCE	Southern California Edison Company
SEC	United States Securities and Exchange Commission
SPP	Southwest Power Pool
SRB	System Reliability Benefit Mechanism
Sundance	Sundance Power Plant
TCA	Transmission cost adjustor
TEAM	Tax expense adjustor mechanism
VIE	Variable interest entity
WEIM	Western Energy Imbalance Market

FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as “estimate,” “predict,” “may,” “believe,” “plan,” “expect,” “require,” “intend,” “assume,” “project,” “anticipate,” “goal,” “seek,” “strategy,” “likely,” “should,” “will,” “could,” and similar words. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from outcomes currently expected or sought by Pinnacle West or APS. In addition to the Risk Factors described in Part I, Item 1A and in Part II, Item 7 — “Management’s Discussion and Analysis of Financial Condition and Results of Operations” of this report, these factors include, but are not limited to:

- our ability to achieve timely and adequate rate recovery of our costs through our regulated rates and adjustor recovery mechanisms, including returns on and of debt and equity capital investment;
- the impacts of federal, state, and local laws, judicial decisions, statutes, regulations, and FERC, NRC, EPA, ACC, and other agency requirements, including as they are changed by legislative and regulatory action as well as executive orders, such as those relating to tax, environment, energy, nuclear plants, and deregulation of the retail electric market;
- our operation of Palo Verde is subject to substantial regulatory oversight and potentially significant liabilities and capital expenditures;
- we are subject to numerous environmental laws and changes to existing laws, or new laws, may increase our costs and impact our business;
- the potential effects of climate change on our electric system, including as a result of weather extremes, such as prolonged drought and high temperature variations in the area where APS conducts its business, as well as the impacts of policy and regulatory changes introduced to address climate change;
- co-owners of our jointly owned generation and transmission facilities may have unaligned goals;
- the willingness or ability of counterparties, participants, and landowners to meet contractual or other obligations or extend the rights for continued generation and transmission operations;
- deregulation of the electric industry and other factors, such as large customers developing large, utility scale generation to serve their energy needs, may result in increased competition;
- variations in demand for electricity, including those due to weather, seasonality (including large increases in ambient temperatures), the general economy or social conditions, customer and sales growth (or decline), data center growth (or lack thereof), including to support the AI industry, the effects of energy conservation measures and DG, and technological advancements;
- wildfires, including those arising as a result of climate change, extreme weather events, or the expansion of the wildland urban interface;
- generation, transmission, and distribution facilities and system operating costs, conditions, performance, and outages;
- our ability and efforts to meet current and anticipated future needs for generation and transmission and distribution facilities in our region at reliable levels, including factors affecting our ability to acquire and develop new resources to serve this load as well as difficulties in accurately forecasting load growth, particularly from high load energy users;
- availability of fuel and water supplies as well as the volatility and costs of fuel and purchased power;
- the direct or indirect effect on our facilities or business from cybersecurity threats or intrusions, data security breaches, terrorist attack, physical attack, severe storms, or other catastrophic events, such as fires, explosions, pandemic health events, or similar occurrences;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- the development of new technologies and the impact they have on the retail and wholesale electricity market and the impacts of our adoption or failure to adopt such technologies;
- the availability and retention of qualified personnel and the need to negotiate collective bargaining agreements with union employees;

- the cost of debt, including increased cost as a result of rising interest rates, and equity capital and our ability to access capital markets when required as well as the impacts a credit rating downgrade would have on us;
- the investment performance of the assets of our nuclear decommissioning trust, captive insurance cell, coal mine reclamation escrow, pension, and other postretirement benefit plans, and the resulting impact on future funding requirements;
- Pinnacle West's cash flow depends on the performance of APS and its ability to make dividends and distributions;
- potential shortfalls in insurance coverage;
- Pinnacle West's ability to meet its debt service obligation could be adversely affected because its debt securities are structurally subordinated to the debt securities and obligations of its subsidiaries;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;
- policy changes in Arizona or other states through ballot initiatives or referenda may increase our cost or operations or affect our business plans;
- general economic conditions, such as tariffs, inflation, and other supply chain constraints, as well as uncertainties associated with the current and future economic environment and conditions in Arizona; and
- disruptions in financial markets could adversely affect our cost of and access to credit and capital markets.

These and other factors are discussed in the Risk Factors described in Part I, Item 1A of this report, and in Part II, Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" of this report, which readers should review carefully before placing any reliance on our financial statements or disclosures. Neither Pinnacle West nor APS assumes any obligation to update these statements, even if our internal estimates change, except as required by law.

PART I

ITEM 1. BUSINESS

Pinnacle West

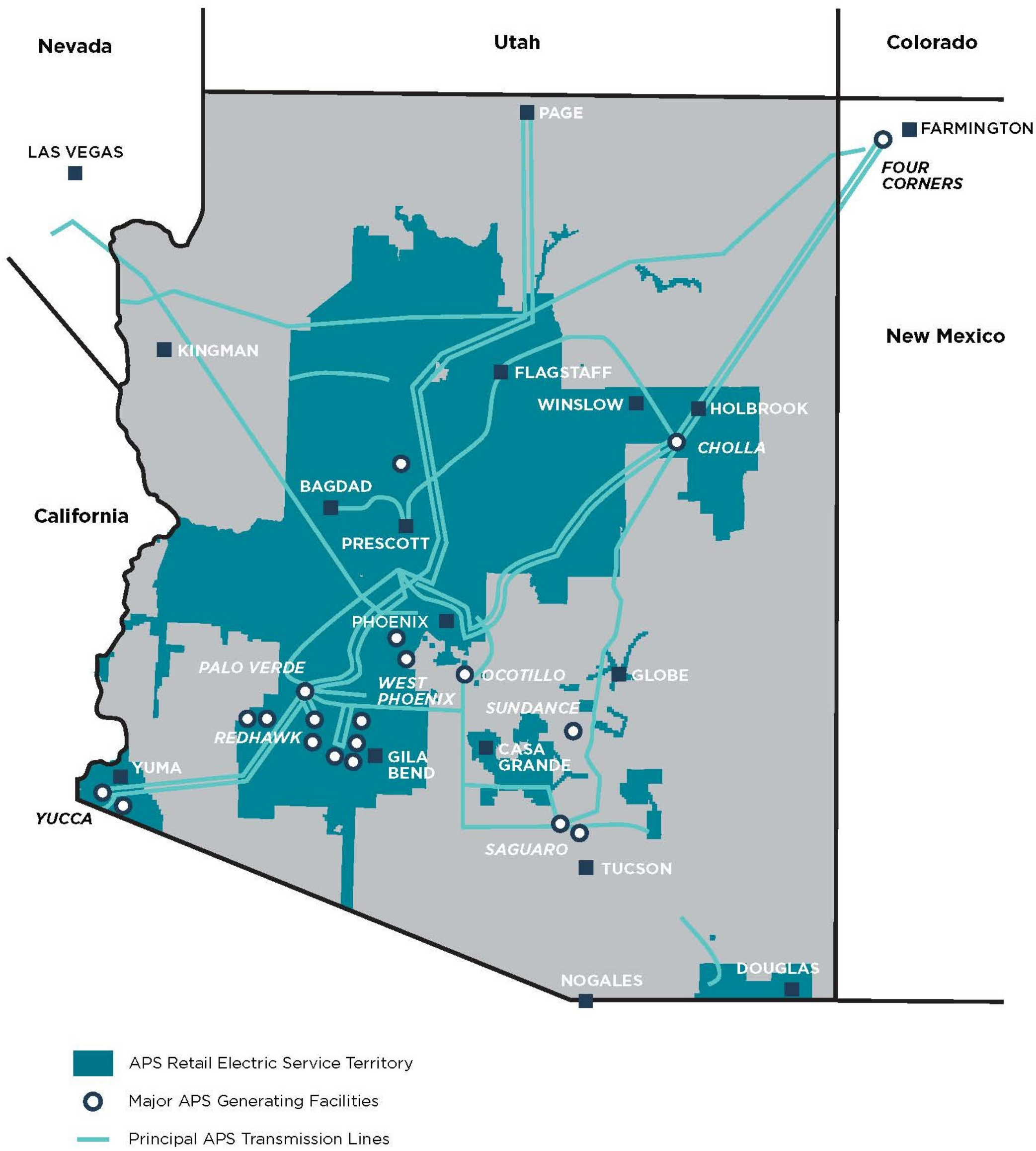
Pinnacle West is an investor-owned electric utility holding company based in Phoenix, Arizona with consolidated assets of approximately $30 billion. We derive essentially all of our revenues and earnings from our principal subsidiary, APS. Since 1886, APS and its affiliates have provided energy and energy-related products to people and businesses throughout Arizona. APS is Arizona’s largest and longest-serving electric company and generates safe, affordable electricity in 11 of Arizona’s 15 counties. Our other active subsidiaries are El Dorado and PNW Power.

Our reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electric service to Native Load customers) and related activities, and includes electricity generation, transmission, and distribution. Our reportable business segment activities are conducted primarily through our wholly-owned subsidiary, APS.

BUSINESS OF ARIZONA PUBLIC SERVICE COMPANY

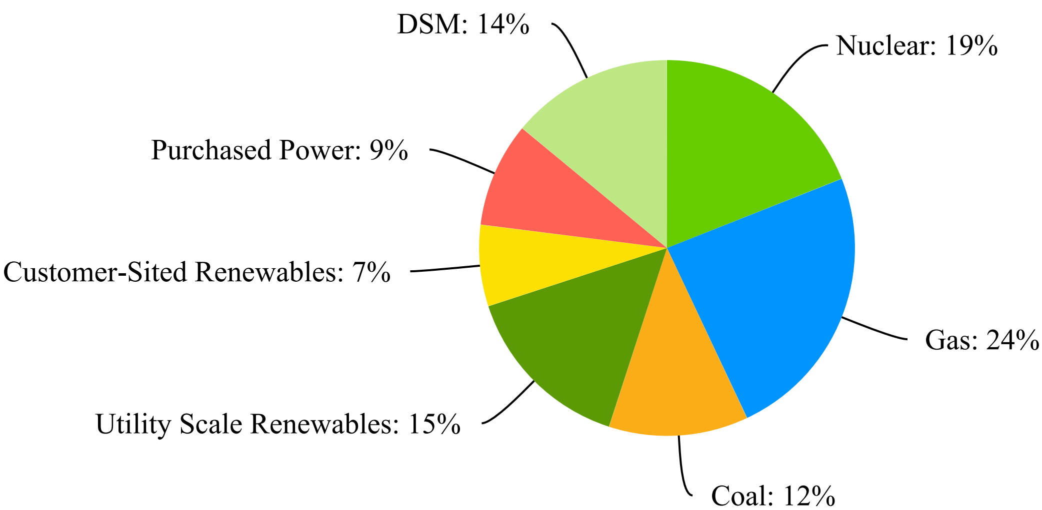
APS currently provides electric service to approximately 1.4 million customers. We own or lease 6,257 MW of regulated generation capacity, and we hold a mix of both long-term and short-term PPAs for additional capacity. During 2025, no single purchaser or user of energy accounted for more than 1.9% of our electric revenues.

The following map shows APS's retail service territory, including the locations of its generating facilities and principal transmission lines.



Energy Sources and Resource Planning

To serve its customers, APS obtains power through its various generation stations and through PPAs. Resource planning is an important function necessary to meet Arizona's future energy needs. APS's sources of energy by type used to supply energy to Native Load customers during 2025 were approximately as follows:



APS has a diverse portfolio of existing and planned resources, including biomass, biogas, coal, energy storage, geothermal, natural gas, solar, and wind. APS has an aspirational goal to be carbon-neutral by 2050, meaning that for any GHG emissions still produced by generation resources in 2050, APS will aim to offset these emissions elsewhere. In 2025, the share of APS's energy supply derived from clean resources was approximately 58%, which includes energy from nuclear, renewables, and DSM as well as PPAs with clean resources. Maintaining a balanced and diverse portfolio of resources helps ensure continued reliable service to our customers in the most affordable manner possible. Every three years, APS performs an IRP, a comprehensive study to identify what resources will be necessary to safely, reliably, and affordably meet the demand and energy needs of its customers over the next 15 years. The latest IRP was released in 2023 and APS is currently developing its next IRP due to be filed with the ACC in August 2026. To help ensure competitive costs for resources, APS regularly issues competitive bid solicitations through the ASRFP process, with the most recent ASRFP being issued in 2025. These ASRFPs are open to bids for all resource types, including customer-scale (behind the meter) and utility-scale (in front of the meter) resources.

As energy demand in Arizona continues to grow, APS remains committed to delivering reliable and affordable service to its customers, with a goal of achieving top quartile reliability compared to its peers. Among other strategies, APS intends to achieve this goal through various methods such as relying on Palo Verde, one of the nation's largest producers of carbon-free energy; seeking a balanced energy mix; managing demand with a modern interactive grid; promoting customer technology and energy efficiency; and optimizing regional resources.

APS also intends to harden its infrastructure in order to improve resiliency, which involves system and operational improvements aimed at reducing the impact of extreme weather events and other disruptions upon APS's operations. Wildfire safety remains a critical focus for APS and other utilities. APS has increased investment in fire mitigation efforts to clear defensible space around its infrastructure, continue ongoing system upgrades, build partnerships with government entities and first responders, and educate customers and communities. Among other resiliency strategies, APS anticipates increasing investments in a modern and more flexible electricity grid with advanced distribution technologies.

Generation Facilities

APS has ownership interests in or leases the nuclear, gas, oil, coal, and solar generating facilities as well as energy storage facilities described below. For additional information regarding these facilities, see Item 2.

Nuclear

Palo Verde Generating Station — Palo Verde is a 3-unit nuclear power plant located approximately 50 miles west of Phoenix, Arizona. APS operates the plant and owns 29.1% of Palo Verde Units 1 and 3 and approximately 23.9% of Unit 2. In addition, APS leases approximately 5.2% of Unit 2, resulting in a 29.1% combined ownership and leasehold interest in that unit. APS has a total entitlement from Palo Verde of 1,146 MW.

Palo Verde Leases — In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back approximately 42% of its share of Palo Verde Unit 2 and certain common facilities. In 2025, APS purchased two of the three leased interests. The remaining lease for approximately 5.2% of Unit 2 expires in 2033. At the end of the lease renewal period, APS will have the option to purchase the leased assets at their fair market value, extend the lease for up to two years, or return the assets to the lessor. See Note 12 for additional information regarding the Palo Verde Unit 2 sale leaseback transactions.

Palo Verde Operating Licenses — Operation of each of the three Palo Verde Units requires an operating license from the NRC. The NRC issued full power operating licenses for Unit 1 in June 1985, Unit 2 in April 1986, and Unit 3 in November 1987, and issued renewed operating licenses for each of the three units in April 2011, which extended the licenses for Units 1, 2, and 3 to June 2045, April 2046, and November 2047, respectively.

Palo Verde Fuel Cycle — The participant owners of Palo Verde are continually identifying their future nuclear fuel resource needs and negotiating arrangements to fill those needs. The fuel cycle for Palo Verde is comprised of the following stages:

- Mining and milling of uranium ore to produce uranium concentrates;
- Conversion of uranium concentrates to uranium hexafluoride;
- Enrichment of uranium hexafluoride;

- Fabrication of fuel assemblies;
- Utilization of fuel assemblies in reactors; and
- Storage and preparation for disposal of spent nuclear fuel.

The Palo Verde participants have contracted for 100% of Palo Verde's requirements for uranium concentrates through 2028 and 70% through 2029; 100% of Palo Verde's requirements for conversion services through 2030 and 32% through 2031; 100% of Palo Verde's requirements for enrichment services through 2028; and 100% of Palo Verde's requirements for fuel fabrication through 2027 for Unit 2 and Unit 1 and 2028 for Unit 3.

Spent Nuclear Fuel and Waste Disposal — The Nuclear Waste Policy Act of 1982 ("NWPA") required the DOE to begin to accept, transport, and dispose of spent nuclear fuel and high-level waste generated by the nation's nuclear power plants by 1998. The DOE's obligations are reflected in a contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste (the "Standard Contract") with each nuclear power plant. The DOE failed to begin accepting spent nuclear fuel by 1998. The DOE had planned to meet its NWPA and Standard Contract disposal obligations by designing, licensing, constructing, and operating a permanent geologic repository at Yucca Mountain, Nevada. In June 2008, the DOE submitted its Yucca Mountain construction authorization application to the NRC, but in March 2010, the DOE filed a motion to dismiss with prejudice the Yucca Mountain construction authorization application. Several legal proceedings followed challenging DOE's withdrawal of its Yucca Mountain construction authorization application and the NRC's cessation of its review of the Yucca Mountain construction authorization application, which were consolidated into one matter at the U.S. Court of Appeals for the District of Columbia Circuit (the "D.C. Circuit"). Following the D.C. Circuit's August 2013 order, the NRC issued two volumes of the safety evaluation report developed as part of the Yucca Mountain construction authorization application. Publication of these volumes does not signal whether or when the NRC might authorize construction of the repository. APS is directly involved in legal proceedings related to the DOE's failure to meet its statutory and contractual obligations regarding acceptance of spent nuclear fuel and high-level waste.

APS Lawsuit for Breach of Standard Contract — In December 2003, APS, acting on behalf of itself and the Palo Verde participants, filed a lawsuit against the DOE in the United States Court of Federal Claims ("Court of Federal Claims") for damages incurred due to the DOE's breach of the Standard Contract. The Court of Federal Claims ruled in favor of APS and the Palo Verde participants in October 2010 and awarded damages to APS and the Palo Verde participants for costs incurred through December 2006.

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the DOE in the United States Court of Federal Claims. The lawsuit sought to recover damages incurred due to DOE's breach of the Standard Contract for failing to accept Palo Verde's spent nuclear fuel and high-level waste from January 1, 2007 through June 30, 2011, pursuant to the terms of the Standard Contract and the NWPA. On August 18, 2014, APS and DOE entered into a settlement agreement, which required DOE to pay the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007, through June 30, 2011. In addition, the settlement agreement provided APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2016, which was extended to December 31, 2025. APS is currently evaluating a proposed extension to the settlement to cover costs paid through December 31, 2028.

APS has recovered costs for eleven claims pursuant to the terms of the August 15, 2014 settlement agreement, for eleven separate time periods during July 1, 2011 through October 31, 2024. The DOE has approved and paid approximately $174.3 million for these claims (APS's share is approximately $50.7 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the ACC's decision from APS's 2017 rate case, this regulatory liability is being refunded to customers. On October 31, 2025, APS submitted its twelfth claim pursuant to the terms of the settlement agreement in the amount of approximately $15.4 million (APS's share is approximately $4.5 million). In February 2026, the DOE approved approximately $15.4 million of this claim.

Waste Confidence and Continued Storage — On June 8, 2012, the D.C. Circuit issued its decision on a challenge by several states and environmental groups of the NRC's rulemaking regarding temporary storage and permanent disposal of high-level nuclear waste and spent nuclear fuel. The petitioners had challenged the NRC's 2010 update to the agency's waste confidence decision and temporary storage rule ("Waste Confidence Decision"). The D.C. Circuit found that the NRC's evaluation of the environmental risks from spent nuclear fuel was deficient, and therefore remanded the Waste Confidence Decision update for further action consistent with National Environmental Policy Act. In September 2013, the NRC issued its draft Generic Environmental Impact Statement ("GEIS") to support an updated Waste Confidence Decision. On August 26, 2014, the NRC approved a final rule on the environmental effects of continued storage of spent nuclear fuel. Renamed as the Continued Storage Rule, the NRC's decision adopted the findings of the GEIS regarding the environmental impacts of storing spent fuel at any reactor site after the reactor's licensed period of operations. As a result, those generic impacts do not need to be re-analyzed in the environmental reviews for individual licenses. The final Continued Storage Rule was subject to continuing legal challenges before the NRC and the Court of Appeals. In June 2016, the D.C. Circuit issued its final decision, rejecting all remaining legal challenges to the Continued Storage Rule.

Palo Verde has sufficient capacity at its on-site independent spent fuel storage installation ("ISFSI") to store all of the nuclear fuel that will be irradiated during the initial operating license period, which ends in December 2027. Additionally, Palo Verde has sufficient capacity at its on-site ISFSI to store a portion of the fuel that will be irradiated during the period of extended operation, which ends in November 2047. If uncertainties regarding the United States government's obligation to accept and store spent fuel are not favorably resolved, APS will evaluate expanding the ISFSI, or alternative storage solutions that may obviate the need to expand the ISFSI, to accommodate all of the fuel that will be irradiated during the period of extended operation.

Nuclear Decommissioning Costs — APS currently relies on an external sinking fund mechanism to meet the NRC financial assurance requirements for decommissioning its interests in Palo Verde Units 1, 2 and 3. The decommissioning costs of Palo Verde Units 1, 2 and 3 are currently included in APS's ACC jurisdictional rates. Decommissioning costs are recoverable through a non-bypassable system benefits charge (paid by all retail customers taking service from the APS system). Based on current nuclear decommissioning trust asset balances, site specific decommissioning cost studies, anticipated future contributions to the decommissioning trusts, and return projections on the asset portfolios over the expected remaining operating life of the facility, we are on track to meet the current site-specific decommissioning costs for Palo Verde at the time the units are expected to be decommissioned. See Note 18 for additional information about APS's nuclear decommissioning trusts.

Palo Verde Liability and Insurance Matters — See "Palo Verde Generating Station — Nuclear Insurance" in Note 14 for a discussion of the insurance maintained for Palo Verde by the Palo Verde participants, including APS.

Natural Gas and Oil Fueled Generating Facilities

APS has six natural gas power plants located throughout Arizona, consisting of Redhawk, located near Palo Verde; Ocotillo, located in Tempe; Sundance, located in Coolidge; West Phoenix, located in southwest Phoenix; Saguaro, located north of Tucson; and Yucca, located near Yuma. Several of the units at Yucca run on either gas or oil. APS has two oil-only power plants: Douglas, located in the town of Douglas, Arizona and Yucca GT-4 in Yuma, Arizona. APS owns and operates each of these plants with the exception of one oil-only combustion turbine unit and one oil and gas steam unit at Yucca that are operated by APS and owned by the Imperial Irrigation District. APS has a total entitlement from these plants of 3,722 MW. A portion of the gas for these plants is financially hedged up to three years in advance of purchasing and that position is converted to a physical gas purchase one month prior to delivery. APS has long-term gas transportation agreements with three different companies, some of which are effective through 2052. Fuel oil is acquired under short-term purchases delivered by truck directly to the power plants.

In 2024, APS contracted for the addition of two combustion turbines (approximately 90 MW in total) at Sundance, which entered into service in 2025, and the addition of eight combustion turbines (approximately 397 MW total) at Redhawk, which are expected to be in service in 2028. APS also plans to add up to 2,000 MW of flexible natural gas generation to its portfolio, designed to help meet the growing around-the-clock energy needs in Arizona.

Coal Fueled Generating Facilities

Four Corners — Four Corners is located in the northwestern corner of New Mexico and was originally a 5-unit coal-fired power plant. APS owns 100% of Units 1, 2 and 3, which were retired as of December 30, 2013. APS operates the plant and owns 63% of Four Corners Units 4 and 5. APS has a total entitlement from Four Corners of 970 MW.

NTEC, a company formed by the Navajo Nation to own the mine that serves Four Corners and develop other energy projects, is the coal supplier for Four Corners. The Four Corners co-owners executed a long-term agreement for the supply of coal to Four Corners from July 2016 through 2031, which was amended and restated on July 1, 2024.

APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also required the approval of the DOI, as did a related federal rights-of-way grant. A federal environmental review was undertaken as part of the DOI review process and culminated in the issuance by DOI of a record of decision on July 17, 2015, justifying the agency action to extend the life of the plant and the adjacent mine.

In June 2021, APS and the owners of Four Corners entered into an agreement that would allow Four Corners to operate seasonally at the election of the owners as early as fall 2023. In July 2024, APS and the owners amended the agreement to retain the option for seasonal operation. Under seasonal operation, one generating unit would be shut down during seasons where electricity demand is reduced, such as the winter and spring. The other unit would remain online year-round, subject to market conditions as well as planned maintenance outages and unplanned outages. As of the date of this report, APS has elected not to begin seasonal operation due to market conditions.

Cholla — Cholla was originally a 4-unit coal-fired power plant, which is located in northeastern Arizona. APS operates the plant and owns 100% of Cholla Units 1, 2 and 3. PacifiCorp owns Cholla Unit 4, and APS operated that unit for PacifiCorp. On September 11, 2014, APS announced that it would close Cholla Unit 2 and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approved a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. APS closed Unit 2 on October 1, 2015. Following the closure of Unit 2, APS had a total entitlement from Cholla of 380 MW. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect for Cholla on April 26, 2017. In December 2019, PacifiCorp notified APS that it planned to retire Cholla Unit 4 by the end of 2020 and the unit ceased operation in December 2020. APS ceased coal-burning operations at Cholla in March 2025 and formally retired Cholla Units 1 and 3 on April 30, 2025.

APS is currently recovering in rates a return on the net-book value of its interest in Cholla and associated depreciation costs. In APS's rate case application filed in 2025 (the "2025 Rate Case"), APS requested recovery in rates of the ongoing environmental remediation and CCR closure costs associated with Cholla and any remaining unrecovered plant costs. The 2025 Rate Case also includes a request for an ongoing deferral order relating to anticipated increased environmental remediation costs relating to Cholla that may be incurred after the 2025 Rate Case proceeding.

Navajo Plant — The Navajo Plant was a 3-unit coal-fired power plant located in northern Arizona. Salt River Project operated the plant and APS owned a 14% interest in Units 1, 2 and 3. APS had a total entitlement from the Navajo Plant of 315 MW. The Navajo Plant site was leased from the Navajo Nation and subject to an easement from the federal government. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017, which allowed for decommissioning activities to begin after the plant ceased operations in November 2019.

APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant. APS will seek continued recovery in rates or the book value of its remaining investment in the plant.

See Note 8 for details related to the regulatory treatment of these coal-fired plants and Note 14 for information regarding APS's coal mine reclamation obligations related to these coal-fired plants.

<u>APS Owned Renewable and Energy Storage Resources</u>

APS owns various utility scale solar resources and DG systems developed through various ACC-approved programs as well as the ASRFP process.

The following table summarizes APS's owned renewable resources currently in operation and under development as of the date of this report. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the projects to the electric grid. Capacity amounts are approximate.

	Location	Actual/Target Commercial Operation Date	Net Capacity (MW) In Operation	Net Capacity (MW) Planned/Under Development
Solar:				
Paloma	Gila Bend, AZ	2011	17	
Cotton Center	Gila Bend, AZ	2011	17	
Hyder I	Hyder, AZ	2012	17	
Chino Valley	Chino Valley, AZ	2012	20	
Hyder II	Hyder, AZ	2013	14	
Foothills	Yuma, AZ	2013	38	
Gila Bend	Gila Bend, AZ	2014	36	
Luke AFB	Glendale, AZ	2015	11	
Desert Star	Buckeye, AZ	2015	10	
Red Rock	Red Rock, AZ	2016	44	
Agave Solar	Arlington, AZ	2023	150	
Ironwood Solar	Dateland, AZ	(a)		168
Multiple Facilities	AZ	Various	4	
Distributed Energy: (b)				
APS Owned (c)	AZ	Various	41	
Total APS Owned			**419**	**168**

(a) This project met plant in service criteria as of December 31, 2025.
(b) DG is produced in direct current and is converted to alternating current for reporting purposes.
(c) Includes Flagstaff Community Power Project, APS School and Government Program, APS Solar Partner Program, and APS Solar Communities Program.

APS deploys a number of advanced technologies on its system, including energy storage. Energy storage provides capacity, improves power quality, can be utilized for system regulation and, in certain circumstances, be used to defer certain traditional infrastructure investments. Energy storage also aids in integrating renewable generation by storing excess energy when system demand is low and renewable production is high and then releasing the stored energy during peak demand hours later in the day and after sunset. APS is utilizing grid-scale energy storage projects to meet customer reliability requirements, increase renewable utilization, and further our understanding of how storage works with other advanced technologies and the grid.

The following table summarizes APS's owned energy storage currently in operation and under development as of the date of this report. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the projects to the electric grid. Capacity amounts are approximate and represent the maximum designed MW the site can provide for three hours, unless noted otherwise.

	Location	Actual/Target Commercial Operation Date	Net Capacity (MW) In Operation	Net Capacity (MW) Planned/Under Development
BESS:				
Paloma	Gila Bend, AZ	2023	17	
Cotton Center	Gila Bend, AZ	2023	17	
Hyder I	Hyder, AZ	2023	16	
Chino Valley (a)	Chino Valley, AZ	2023	19	
Hyder II	Hyder, AZ	2023	14	
Foothills	Yuma, AZ	2023	35	
Gila Bend	Gila Bend, AZ	2023	32	
Desert Star	Buckeye, AZ	2022	10	
Red Rock (a)	Red Rock, AZ	2023	41	
Agave (a)	Arlington, AZ	(b)		150
Total APS Owned			**201**	**150**

(a) Capacity amounts represent the maximum designed MW the site can provide for four hours.
(b) This project met plant in service criteria as of December 31, 2025.

PPAs and Other Third-Party Owned Resources

In addition to its own available generation and storage capacity, APS purchases electricity under various arrangements, including through long-term contracts, purchases through short-term markets to supplement its owned or leased generation and hedge its energy requirements, and other arrangements with third parties, such as customer programs like APS's Storage Rewards Pilot Program. A portion of APS's purchased power expense is netted against wholesale sales on the Consolidated Statements of Income. See Note 13. APS continually assesses its need for additional capacity resources to ensure system reliability.

APS's non-renewable purchased power under long-term contracts as of the date of this report is summarized in the table below. Capacity amounts are approximate.

Type	Dates Available	Net Capacity (MW)
Tolling Agreement	May 1 through April 30, 2021-2025	463
Extension Term	May 1 through October 31, 2025-2032	525
Tolling Agreement	June 1 through September 30, 2020-2025	565
First Extension Term	May 1 through October 31, 2026	575
Second Extension Term	May 1 through October 31, 2027-2038	600
Tolling Agreement	June 1 through September 30, 2020-2026	570
Extension Term	May 1 through October 31, 2027-2034	600

Non-APS owned renewable energy resources currently in operation and planned/under development as of the date of this report are summarized in the table below. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the projects to the electric grid. Capacity amounts are approximate.

	Location	Actual/ Target Commercial Operation Date	Term (Years)	Net Capacity (MW) In Operation	Net Capacity (MW) Planned/Under Development
PPAs					
Solar:					
Solana	Gila Bend, AZ	2013	30	250	
RE Ajo	Ajo, AZ	2011	25	5	
Sun E AZ 1	Prescott, AZ	2011	30	10	
Saddle Mountain	Tonopah, AZ	2012	30	15	
Badger	Tonopah, AZ	2013	30	15	
Gillespie	Maricopa County, AZ	2013	30	15	
Mesquite Solar 5	Tonopah, AZ	2023	20	60	
Sunstreams 3	Arlington, AZ	2024	20	215	
Yuma Solar Energy	Yuma County, AZ	2025	20	70	
Harquahala Sun 2	Tonopah, AZ	2025	20	300	
Sunstreams 4	Arlington, AZ	2025	20	300	
Serrano Solar	Pima & Pinal County, AZ	2025	20	170	
CO Bar Solar C	Coconino County, AZ	2027	20		206
Hashknife 1	Navajo County, AZ	2026	20		275
Catclaw	Buckeye, AZ	2026	20		225
Papago Solar	Maricopa County, AZ	2026	20		150
Hashknife 2	Navajo County, AZ	2027	20		200
Kitt	Eloy, AZ	2026	20		100
Pioneer	Yuma, AZ	2027	20		300
Maricopa Energy Center Phase 1	Maricopa County, AZ	2026	20		183
Maricopa Energy Center Phase 2	Maricopa County, AZ	2027	20		367
Snowflake Solar	Snowflake, AZ	2027	20		475
Wind:					
Aragonne Mesa	Santa Rosa, NM	2022	20	200	
High Lonesome	Mountainair, NM	2009	30	100	
Perrin Ranch Wind	Williams, AZ	2012	25	99	
Chevelon Butte	Winslow, AZ	2023	20	238	
Chevelon Butte II	Winslow, AZ	2024	20	216	
West Camp Wind Farm	Navajo County, AZ	2026	20		500
Geothermal:					
Salton Sea	Imperial County, CA	2006	23	10	
Biomass:					
Snowflake	Snowflake, AZ	2008	25	14	
Biogas:					
NW Regional Landfill	Surprise, AZ	2012	20	3	
Total PPAs				**2,305**	**2,981**
Distributed Energy (a)					
Solar					
Third-party Owned	AZ	Various		1,773	82
Agreement 1	Bagdad, AZ	2011	25	15	
Agreement 2	AZ	2011-2012	20-21	18	
Total Distributed Energy				**1,806**	**82**
Total				**4,111**	**3,063**

(a) DG is produced in direct current and is converted to alternating current for reporting purposes.

Non-APS owned energy storage resources currently in operation and planned/under development as of the date of this report are summarized in the table below. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the projects to the electric grid. Capacity amounts are approximate and reported as nameplate capacity in MW and represent the maximum designed MW the site can provide for four hours.

	Location	Actual/ Target Commercial Operation Date	Term (Years)	Nameplate Capacity (MW) In Operation	Nameplate Capacity (MW) Planned/Under Development
BESS PPAs					
Mesquite 5	Tonopah, AZ	2023	20	60	
West Wing 1	Peoria, AZ	2024	20	80	
El Sol	Phoenix, AZ	2024	20	50	
Sun Streams 3	Arlington, AZ	2024	20	215	
Yuma	Yuma, AZ	2025	20	67	
Westwing 2	Peoria, AZ	2025	20	120	
Harquahala Sun 2	Quartzsite, AZ	2025	20	300	
Scatterwash 1	Phoenix, AZ	2025	20	170	
Pluto BESS	Goodyear, AZ	2025	20	75	
Papago	Tonopah, AZ	2025	20	300	
Scatterwash 2	Phoenix, AZ	2025	20	85	
Seranno	Pima County, AZ	2025	20	214	
Sun Streams 4	Arlington, AZ	2025	20	300	
Justice	Buckeye, AZ	2026	20		150
Catclaw	Buckeye, AZ	2026	20		250
Hashknife 1	Navajo County, AZ	2026	20		275
Beehive	Peoria, AZ	2026	20		250
Desert Bloom	Peoria, AZ	2026	20		150
Maricopa Energy Center Phase 1	Maricopa County, AZ	2026	20		183
Maricopa Energy Center Phase 2	Maricopa County, AZ	2026	20		367
Kitt	Eloy, AZ	2026	20		100
White Tank	Avondale, AZ	2027	20		100
Pioneer	Yuma, AZ	2027	20		300
Co Bar C	Coconino County, AZ	2027	20		206
Hashknife 2	Navajo County, AZ	2027	20		200
Harquahala Flats	Tonopah, AZ	2027	20		225
Snowflake PVS	Snowflake, AZ	2027	20		475
Harquahala Flats 2	Tonopah, AZ	2027	20		225
Total BESS PPAs				**2,036**	**3,456**
Distributed BESS					
Third-party Owned	**AZ**	**Various**		**103**	**37**
Total				**2,139**	**3,493**

Current and Future Resources

Current Demand and Reserve Margin

Electric power demand is generally seasonal. In Arizona, demand for power peaks during the hot summer months. APS's 2025 peak one-hour demand on its electric system was recorded on August 7, 2025, at 8,648 MW, compared to the 2024 peak of 8,210 MW recorded on August 4, 2024. APS carries reserves across all hours of the year to respond to system events and uncertainty in load and resource performance. For 2026, APS is building resources and has procured long-term PPAs to meet the industry standard of reliability for its growing load and increased weather volatility.

Future Resources and Resource Plan

ACC rules require utilities to develop 15-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary rule requirements and whether it should be acknowledged. On October 8, 2024, the ACC acknowledged APS's 2023 IRP and approved certain amendments to the IRP process, including requirements for APS to demonstrate resource adequacy prior to exiting Four Corners as well as analysis of impacts from western market participation and planned resource requirements in the next IRP. APS's next IRP is in process and due to be filed with the ACC in August 2026.

Western Energy Imbalance Market and Wholesale Market

In 2016, APS began to participate in the WEIM, a voluntary, real-time optimization market operated by the CAISO. The WEIM allows for rebalancing supply and demand in 15-minute blocks and dispatching generation every five minutes, instead of the traditional one-hour blocks. APS continues to expect that its participation in the WEIM will lower its fuel and purchased-power costs, improve situational awareness for system operations in the Western Interconnection power grid, and improve integration of APS's renewable resources. APS participated in market design and tariff development of Markets+, a day-ahead and real-time market offering from SPP. The Markets+ tariff was filed with FERC on March 29, 2024 and was approved on January 16, 2025. APS has made a market decision to pursue participation in SPP Markets+, which is expected to go live in October 2027. In addition, APS is participating in the Western Resource Adequacy Program administered by Western Power Pool and is transitioning to full binding participation in 2027 or 2028. These regional efforts are driven by the objectives of reducing customer cost and improving reliability.

Competitive Environment and Regulatory Oversight

Retail

The ACC regulates APS's retail electric rates and its issuance of securities. The ACC must also approve any significant transfer or encumbrance of APS's property used to provide retail electric service and approve or receive prior notification of certain transactions between Pinnacle West, APS, and their respective affiliates. See Note 8 for information regarding ACC's regulation of APS's retail electric rates.

APS is subject to varying degrees of competition from other investor-owned electric and gas utilities in Arizona (such as Southwest Gas Corporation), as well as cooperatives, municipalities, electrical districts, and similar types of governmental or non-profit organizations. In addition, some customers, particularly industrial and large commercial customers, may own and operate generation facilities to meet some or all of their own energy requirements. This practice is becoming more popular with customers installing or having installed products such as rooftop solar panels to meet or supplement their energy needs. While historically this practice has been largely focused on customers installing behind the meter technologies, such as rooftop solar panels or back-up generators to meet or supplement their energy needs, today APS and utilities broadly are seeing a rise in large customers seeking to develop or accelerate large, utility scale generation projects to serve their energy needs. This is creating the need for new and creative commercial and regulatory constructs to ensure reliability, cost recovery, and the equitable allocation of costs among customer groups.

Wholesale

FERC regulates rates for wholesale power sales and transmission services. See Note 8 for information regarding APS's transmission rates. During 2025, approximately 4.5% of APS's electric operating revenues resulted from such sales and services. APS's wholesale activity primarily consists of managing fuel and purchased power supplies to serve retail customer energy requirements. APS also sells, in the wholesale market, its generation output that is not needed for APS's Native Load and, in doing so, competes with other utilities, power marketers and independent power producers. Additionally, subject to specified parameters, APS hedges both electricity and natural gas. The majority of these activities are undertaken to mitigate risk in APS's portfolio.

Transmission and Delivery

APS continues to work closely with customers, stakeholders, and regulators to identify and plan for transmission needs that support new customers, system reliability, access to markets and clean energy development. The capital expenditures table presented in the "Liquidity and Capital Resources" section of Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of this report includes new APS transmission projects, along with other transmission costs for upgrades and replacements, including those for data center and semi-conductor manufacturing development. To prioritize reliability and meet substantial growth in residential and commercial energy needs, APS has developed a future-focused, strategic transmission plan (the "Ten-Year Transmission Plan"). The Ten-Year Transmission Plan includes critical transmission projects and represents a significant upgrade to APS's transmission system. These projects are intended to support growing energy needs, strengthen reliability, and allow for the connection of new resources.

APS is also working to establish and expand advanced grid technologies throughout its service territory to provide long-term benefits both to APS and its customers. APS is strategically deploying a variety of technologies that are intended to allow customers to better manage their energy usage, minimize system outage durations and frequency, enable customer choice for new customer sited technologies, and facilitate greater cost savings to APS through improved reliability and the automation of certain delivery functions.

Environmental Matters

Climate Change

Legislative Initiatives. There have been no recent successful attempts by Congress to pass legislation that would regulate GHG emissions, and it is unclear at this time whether legislation regulating or limiting utility-sector GHG emissions introduced during prior sessions of Congress will become law. In the event climate change legislation ultimately passes, the actual economic and operational impact of such legislation on APS depends on a variety of factors, none of which can be fully known until a law is written, enacted, and the specifics of the resulting program are established. These factors include, without limitation, the terms of the legislation with regard to allowed GHG emissions; the cost to reduce emissions; in the event a cap-and-trade program is established, whether any permitted emissions allowances will be allocated to source operators free of cost or auctioned (and, if so, the cost of those allowances in the marketplace) and whether offsets and other measures to moderate the costs of compliance will be available; and, in the event of a carbon tax, the amount of the tax per pound of carbon dioxide ("CO_2") equivalent emitted.

In addition to federal legislative initiatives, state-specific initiatives may also impact our business. While Arizona has no pending legislation regulating GHGs, the California legislature enacted AB 32 and Senate Bill ("SB") 1368 in 2006 to address GHG emissions. In October 2011, the California Air Resources Board ("CARB") approved final regulations that established a state-wide cap on GHG emissions beginning on January 1, 2013, and established a GHG allowance trading program under that cap. The first phase of the program, which applies to, among other entities, importers of electricity, commenced on January 1, 2013. Under the program, entities selling electricity into California, including APS, must hold carbon allowances to cover GHG emissions associated with electricity sales into California from outside the state. APS is authorized to recover the cost of these carbon allowances through the PSA.

The California legislature also enacted SB 219, SB 253, and SB 261, which mandate climate-related disclosures for certain companies doing business in California. CARB issued proposed regulations for the bills in December 2025, with a proposed deadline of August 10, 2026 for submitting SB 253 reports. Written comments on the proposal were due on February 9, 2026. The U.S. Court of Appeals for the Ninth Circuit granted a motion to enjoin enforcement of SB 261, which requires climate-related financial risk reporting by a January 1, 2026 compliance deadline. We do not currently believe we would be required to make disclosures pursuant to these bills.

Regulatory Initiatives. In 2009, EPA determined that GHG emissions endanger public health and welfare. As a result of this "Endangerment Finding," EPA determined that the Clean Air Act required new regulatory requirements for new and modified major GHG emitting sources, including power plants. APS will generally be required to consider the impact of GHG emissions as part of its traditional New Source Review analysis for new major sources and major modifications to existing plants.

EPA's regulation of carbon dioxide emissions from electric utility power plants has proceeded in fits and starts over most of the last decade. Starting on August 3, 2015, EPA finalized the Clean Power Plan, which was the agency's first effort at such regulation through system-wide generation dispatch shifting. Those regulations were subsequently repealed by EPA on June 19, 2019 and replaced by the Affordable Clean Energy regulations, which were a far narrower set of rules. While the U.S. Court of Appeals for the D.C. Circuit subsequently vacated the Affordable Clean Energy regulations on January 19, 2021, and ordered a remand for EPA to develop replacement regulations consistent with the original 2015 Clean Power Plan, the U.S. Supreme Court subsequently reversed that decision on June 30, 2022, holding that the Clean Power Plan exceeded EPA's authority under the Clean Air Act.

In the latest final regulations governing power plant carbon dioxide emissions, released April 25, 2024, EPA issued emission standards and guidelines for various subcategories of new and existing power plants. Unlike EPA's Clean Power Plan regulations from 2015, which took a broad, system-wide approach to regulating carbon emissions from electric utility fossil-fuel burning power plants, these new federal regulations are limited to measures that can be installed at individual power plants to limit planet-warming carbon-dioxide emissions.

Under current rules, carbon emission performance standards apply based on the annual capacity factors for new natural gas-fired combustion turbine power plants. The highest utilization combustion turbines must be retrofitted for CCS by 2032. Intermediate or low-load natural gas fired combustion turbines with 40% or less capacity factors do not require add-on pollution controls. Instead, natural gas-fired combustion turbines with capacity factors of up to 20% are effectively unregulated, while turbines with capacity factors over 20% and up to 40% are subject to carbon dioxide emission rate limitations.

For coal-fired power plants, instead of imposing regulations based on capacity and utilization, EPA finalized subcategories based on planned retirement dates. Facilities retiring before 2032 are effectively exempt from regulation; those that retire between 2032 and 2038 must co-fire with natural gas starting in 2030; and those that retire in 2039 or later must install CCS controls by 2032.

As of May 10, 2024, several states, electric utility companies, affiliated trade associations, and other entities filed petitions for review of these regulations in the D.C. Circuit Court of Appeals. APS is participating in that litigation as part of an ad hoc coalition of electric utility companies, independent power producers, and trade groups, called Electric Generators for a Sensible Transition. On February 5, 2025, EPA filed an unopposed motion requesting that the D.C. Circuit Court of Appeals hold the GHG regulations case in abeyance for 60 days and withhold issuing an opinion while the new leadership at EPA evaluates the rule and determines how it wishes to proceed. On February 19, 2025, the Court granted EPA's motion. EPA subsequently filed a second motion asking the Court to keep the GHG regulations case in abeyance for an indefinite period of time given EPA's anticipated reconsideration of the rules, with EPA providing status reports every 90 days. The D.C. Circuit granted EPA's motion for an indefinite abeyance on April 25, 2025. We cannot predict the outcome of the litigation challenging EPA's current carbon emission standards for power plants.

If the current regulations were to remain in effect, they would likely lead to a material increase in APS's costs to build, operate, and maintain new, frequently operated gas-fired power plants. The regulatory deadlines in 2032 by which new, frequently operated gas-fired power plants must install CCS and achieve 90% capture efficiency may not be feasible. Future resource plans and procurement efforts implicating the development of such new generation remain pending and, as such, at this time APS is not able to quantify the financial impact associated with EPA's existing GHG regulations for power plants.

On June 11, 2025, EPA put forth a proposed rule with two scenarios for repealing the GHG regulations finalized in 2024. EPA's primary proposal entails a full repeal of the GHG regulations based on a finding that GHG emissions from fossil fuel-fired power plants do not present a "significant contribution" to dangerous air pollution, thereby eliminating the 2024 GHG power plant regulations in their entirety.

Under EPA's alternative proposal, only certain portions of the 2024 GHG regulations would be repealed based on a finding that they are unlawful, including the section 111(d) emission guidelines for existing fossil fuel-fired steam generating units (coal-fired power plants), the CCS-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base-load stationary combustion turbines (i.e., those operating at greater than 40% annual capacity factors). This targeted approach would eliminate the CCS and natural gas co-firing technology-based pollution limits that would apply to both existing coal-fired power plants and new gas-fired combustion turbine power plants. However, efficiency-based standards for new combustion turbines would remain in place under this alternative proposal.

EPA's proposed rule to repeal the 2024 GHG regulations was published in the Federal Register on June 17, 2025. Comments were due by August 7, 2025. We cannot predict the outcome of future rulemaking or other regulatory proceedings aimed at changing or eliminating the current EPA emission standards for power plants. Further changes to these regulations may also face judicial review. APS cannot predict the outcome of any such litigation.

On February 18, 2026, EPA's repeal of the 2009 "Endangerment Finding" was finalized and published in the Federal Register. This action is expected to provide legal and regulatory support for EPA's pending proposals seeking to eliminate or significantly limit the scope of the current EPA carbon emission standards and guidelines for new and existing power plants. The repeal of the "Endangerment Finding" is subject to judicial review, with lawsuits being filed on February 18, 2026 in the D.C. Circuit Court of Appeals seeking to challenge the repeal. We cannot the predict the outcome of such litigation.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone NAAQS and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, RCRA, Superfund, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of APS's fossil-fuel powered plants or the willingness or ability of power plant participants to fund any required equipment upgrades or continue their participation in these plants. The economics of continuing to own certain resources, particularly our coal plants, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement but cannot predict whether it would obtain such recovery.

Sustainability Reporting

APS prepares an annual inventory of GHG emissions from its operations. For APS's operations involving fossil-fuel electricity generation and electricity transmission and distribution, APS's annual GHG inventory is reported to EPA under the EPA GHG Reporting Program. In addition to reporting to EPA, we publicly report Scope 1 and 2 GHG emissions. This performance data is then communicated to the public in Pinnacle West's annual Corporate Responsibility Report and is available on our website (*www.pinnaclewest.com/corporate-responsibility*). The report provides information related to the Company and its approach to sustainability and its workplace and environmental performance. The information on Pinnacle West's website, including its Corporate Responsibility Report, is not incorporated by reference into or otherwise a part of this report.

EPA Environmental Regulation

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCRs, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the RCRA and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments and are the subject of the regulatory and judicial activities described below.

Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

- Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to either authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. ADEQ has taken steps to develop a CCR permitting program and proposed state regulations governing CCR permitting in the summer of 2024. On April 1, 2025, the Arizona Governor's Regulatory Review Council approved ADEQ's proposed rulemaking governing CCR permitting. ADEQ will submit an approval package to EPA, which will have to approve the entire state program before it is operational. It remains unclear when EPA would approve that permitting program pursuant to the Water Infrastructure Improvements for the Nation Act. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits, which would impact facilities like Four Corners located on the Navajo Nation. The proposal remains pending.

- On March 1, 2018, as a result of a settlement with certain environmental groups, EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019 to add a specific health-based groundwater protection standard for boron, EPA has yet to take action on this proposal.

We cannot predict the outcome of these regulatory proceedings or when EPA will take final action on those matters that are still pending. Depending on the eventual outcome, the costs associated with APS's management of CCR could materially increase, which could affect our financial condition, results of operations, or cash flows.

On April 25, 2024, EPA took final action on a proposal to expand the scope of federal CCR regulations to address the impacts from historical CCR disposal activities that would have ceased prior to 2015. This new class of CCRMUs, which contain at least 1,000 tons of CCR, broadly encompass any location at an operating coal-fired power plant where CCRs would have been placed on land. As proposed, this would include not only historically closed landfills and surface impoundments but also prior applications of CCR beneficial use (with exceptions for historical roadbed and embankment applications). Existing CCR regulatory requirements for groundwater monitoring, corrective action, closure, post-closure care, and other requirements will be imposed on such CCRMUs. Under EPA's legacy 2024 CCRMU rule, initial CCRMU site surveys originally due to be completed by February 2026 and final site investigation reports by February 2027.

On February 10, 2026, EPA published a final rule extending multiple compliance deadlines applicable to CCRMUs established under the prior rule. The final rule extends the deadline for completing Parts One and Two of Facility Evaluation Reports by one year to February 2027 and February 2028, respectively. EPA also extended associated compliance deadlines for groundwater monitoring and certain closure requirements. On February 9, 2026, EPA sent to the Office of Management and Budget for review a rule proposal that is anticipated to provide more substantive changes to certain aspects of the legacy 2024 CCRMU rule.

APS is still in the process of evaluating the impacts of these CCRMU regulations on its business and cannot predict the outcome of any future rulemaking or other regulatory proceedings aimed at changing the current EPA CCRMU rules. Based on the information available to APS at this time, APS cannot reasonably estimate the cost of the entire CCRMU asset retirement obligation. Depending on the outcome of the pending legacy 2024 CCRMU rule amendments and APS's evaluations, the costs associated with APS's management of CCR could materially increase, which could affect our financial condition, results of operations, or cash flows.

APS currently disposes of CCR in ash ponds and dry storage areas at Four Corners. The Navajo Plant disposed of CCR only in a dry landfill storage area. The Cholla Plant disposed of CCR in ash ponds and dry storage areas prior to ceasing coal-fired operations. Additionally, the CCR rule requires ongoing, phased groundwater monitoring. As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must have ceased operating and initiated closure as of April 11, 2021 (except for those disposal units at Cholla that had been subject to alternative closure, which initiated closure work on June 30, 2025). APS completed the assessments of corrective measures on June 14, 2019; however, additional investigations and engineering analyses that will support the remedy selection are still underway. In addition, APS has also solicited input from the public and hosted public hearings as part of this process. APS's estimates for its share of corrective action and monitoring costs at Four Corners and Cholla are captured within the Asset Retirement Obligations, and Removal Costs within Regulatory Liabilities. As APS continues to implement the CCR rule's corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until we have fully completed the corrective action assessment and final remedy selection process, we cannot predict any ultimate impacts to APS; however, at this time APS does not believe that any potential changes to the cost estimate from the CCR rule's corrective action assessment process for Four Corners or Cholla would have a material impact on its financial condition, results of operations, or cash flows.

Effluent Limitation Guidelines. EPA published ELGs on October 13, 2020, and, based off those guidelines, APS completed a NPDES permit modification for Four Corners on December 1, 2023. The ELG standards finalized in October 2020 relaxed the "zero discharge" standard for bottom ash transport waters EPA finalized in September 2015. However, on April 25, 2024, EPA finalized new ELG regulations that once again require "zero discharge" standards for flows of bottom ash transport water at power plants like Four Corners. For power plants that permanently cease operations by December 31, 2034, such facilities can continue to comply with the 2020 ELG standards. APS is currently evaluating its compliance options for Four Corners based on the ELG regulations finalized in April 2024 and is assessing what impacts the new standards will have on our financial condition, results of operations, and cash flows.

On December 31, 2025, EPA published a final rule extending by five years the compliance deadlines for achieving the 2024 zero-discharge standards for bottom ash transport wastewater from year-end 2029 to year-end 2034, among other changes to the previous rules. EPA is also collecting additional information on zero-discharge technologies, including cost and performance data, to inform future potential rulemakings to modify or relax the current zero-discharge ELG standards. We cannot predict the outcome of any future rulemaking or other regulatory proceedings aimed at modifying the current ELG standards.

Ozone National Ambient Air Quality Standards. On October 1, 2015, EPA finalized revisions to the primary ground-level ozone NAAQS at a level of 70 parts per billion ("ppb"). Further, on December 23, 2020, EPA issued a final regulation retaining the current primary NAAQS for ozone, following a required scientific review process. With ozone standards becoming more stringent, our fossil generation units will come under increasing pressure to reduce emissions of nitrogen oxide ("NOx") and volatile organic compounds, and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas. EPA was expected to designate attainment and nonattainment areas relative to the new 70 ppb standard by October 1, 2017. While EPA took action designating attainment and unclassifiable areas on November 6, 2017, the Agency's final action designating non-attainment areas was not issued until April 30, 2018. At that time, EPA designated the geographic areas containing Yuma and Phoenix, Arizona as in non-attainment with the 2015 70 ppb ozone NAAQS. The vast majority of APS's natural gas-fired EGUs are located in these jurisdictions. Areas of Arizona and the Navajo Nation where the remainder of APS's fossil-fuel fired electric generating unit fleet is located were designated as in attainment. On October 7, 2022, EPA took final action designating Maricopa County, which includes the Phoenix, Arizona metropolitan area, as "moderate" for non-attainment with the governing ozone NAAQS, which provided for an August 3, 2024 attainment "deadline" by which the area would be automatically designated as in "serious" non-attainment unless it achieved the 2015 ozone NAAQS. At this time, an EPA proposal (dated November 19, 2025) is pending that finds Maricopa County would have attained compliance with the 2015 ozone NAAQS by the "moderate" non-attainment deadline but for emissions emanating from outside the United States. If finalized as proposed, this action would maintain the current non-attainment status for Maricopa County without implicating more stringent emissions limitations for this area, among other requirements. At this time, APS is unable to predict the outcome of this proceeding, including whether the November 19, 2025 proposal will be adopted by EPA. If finalized, this proposal is also subject to judicial review. APS will continue to monitor these standards as they are implemented within the jurisdictions affecting the Company's operations.

EPA Good Neighbor Proposal for Arizona. On March 15, 2023, EPA issued its final Good Neighbor Plan for 23 states in order to ensure that the cross-state transport of ozone forming emissions does not interfere with downwind state compliance with the NAAQS. Thermal power plant emission limitations are a key aspect of these regulations, which involve emission allowance trading for NOx emissions. While Arizona was not among the 23 states subject to EPA's March 2023 final action, EPA announced on January 23, 2024, that it was proposing to add Arizona and New Mexico (along with two other additional states) to EPA's NOx emission allowance trading program finalized last year. That proposal involves adding these states to the Good Neighbor Plan and disapproving the corresponding provisions of each state's State Implementation Plan. Because APS operates thermal power plants within Arizona and those portions of the Navajo Nation within New Mexico, APS's power plants would be subject to EPA's Good Neighbor Plan upon finalization of this proposal. EPA's final Good Neighbor Plan is subject to ongoing judicial review in the D.C. Circuit Court of Appeals. On June 27, 2024, the U.S. Supreme Court granted a motion to stay the effectiveness of EPA's final Good Neighbor Plan pending the resolution of the litigation. As such, APS will not be impacted by the Good Neighbor Plan until the outcome of this litigation is finalized. In addition, on December 19, 2024, EPA announced that it was withdrawing its proposal to add Arizona (along with other western states) to the federal Good Neighbor Plan. On March 12, 2025, EPA announced its intention to reconsider the Good Neighbor Plan and on January 30, 2026, EPA published a proposed rule in the Federal Register that would approve Arizona's and New Mexico's State Implementation Plans concerning the cross-state transport of ozone forming emissions. Such approval, if finalized as proposed, would remove APS's operations in Arizona and New Mexico from the scope of future efforts to regulate such emissions. APS cannot predict the outcome of this pending regulatory action nor when EPA may take final action on this proposal. If finalized as proposed, this action would then be subject to judicial review and APS cannot predict the outcome of such litigation, if any arises. In addition, APS cannot predict the outcome of any future EPA efforts to add Arizona or New Mexico to a future federal program addressing the cross-state transport of ozone-forming emissions. Should a federal program like the Good Neighbor Plan ultimately be imposed on APS and its operations in Arizona and New Mexico, it would have material impact on both the costs to operate current APS power plants and APS's ability to develop new thermal generation to serve load. At this time, APS cannot predict the impact on the Company's financial condition, results of operations, or cash flows.

Revised Mercury and Air Toxics Standard ("MATS") Proposal. On February 20, 2026, EPA issued a final rule repealing the 2024 revisions to MATS regulations governing emissions of toxic air pollution from existing coal-fired power plants. The repeal of the 2024 amendment means that MATS regulations revert to the pre-existing framework for MATS emission limits established in 2012. As a result, the 2024 revisions that would have increased the stringency of filterable particulate matter limits used to demonstrate compliance with MATS and required the use of continuous emissions monitoring systems to ensure compliance (as opposed to periodic performance testing) will not take effect for existing coal-fired power plants, such as Four Corners.

Superfund-Related Matters. CERCLA establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who released, generated, transported to, or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible (each a "PRP"). PRPs may be strictly, jointly, and severally liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 ("OU3"), in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study ("RI/FS"). The RI/FS for OU3 was finalized and submitted to EPA at the end of 2022. EPA notified APS that the RI/FS was approved on September 11, 2024. On September 25, 2025, EPA executed a final ROD adopting the OU3 remedies proposed in the approved RI/FS OU3. APS's expenditures related to this investigation and study are approximately $3 million. APS anticipates it may incur additional expenditures in the future, but because the final costs associated with remediation requirements set forth in the RI/FS and ROD are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated; however, APS does not expect the outcome to have a material impact on its financial position, results of operations, or cash flows.

In connection with APS's status as a PRP for OU3, since 2013 APS and at least two dozen other parties have been defendants in various CERCLA lawsuits stemming from allegations that contamination from OU3 and elsewhere has impacted groundwater wells operated by the Roosevelt Irrigation District. At this time, only one active lawsuit remains pending in the U.S. District Court for Arizona, which concerns $8.3 million in remediation legal expenses. APS is unable to predict the outcome of any further litigation related to this claim or APS's share of liability related to that claim; however, APS does not expect the outcome to have a material impact on its financial position, results of operations, or cash flows.

On February 28, 2022, EPA provided APS with a request for information under CERCLA related to APS's Ocotillo power plant site located in Tempe, Arizona. In particular, EPA seeks information from

APS regarding APS's use, storage, and disposal of substances containing PFAS at the Ocotillo power plant site in order to aid EPA's investigation into actual or threatened releases of PFAS into groundwater within the South Indian Bend Wash Superfund site. The South Indian Bend Wash Superfund site includes the APS Ocotillo power plant site. APS filed its response to this information request on April 29, 2022. On January 17, 2023, EPA contacted APS to inform APS that it would be commencing on-site investigations within the South Indian Bend Wash site, including the Ocotillo power plant, and performing a remedial investigation and feasibility study related to potential PFAS impacts to groundwater over the next two to three years. APS estimates that its costs to oversee and participate in the remedial investigation work will be approximately $1.7 million. At the present time, we are unable to predict the outcome of this matter, and any further expenditures related to necessary remediation, if any, or further investigations cannot be reasonably estimated.

Four Corners National Pollutant Discharge Elimination System Permit

The latest NPDES permit for Four Corners was issued on September 30, 2019. Based upon a November 1, 2019 filing by several environmental groups, the Environmental Appeals Board up review of the Four Corners NPDES Permit. The Environmental Appeals Board denied the environmental group petition on September 30, 2020. While on January 22, 2021, the environmental groups filed a petition for review of the Environmental Appeals Board's decision with the U.S. Court of Appeals for the Ninth Circuit, the parties to the litigation (including APS) finalized a settlement on May 2, 2022. This settlement required investigation of thermal wastewater discharges from Four Corners over an extended period of time while administratively closing the litigation filed in January of 2021 during the pendency of the investigation. Having completed the investigation in accordance with the settlement, the Ninth Circuit Court of Appeals granted a motion to dismiss the litigation on October 3, 2025. In addition, as of October 9, 2025, EPA deemed APS's application for a renewal NPDES Permit for Four Corners to be administratively complete. APS cannot predict the timing or outcome of EPA's evaluation of this pending renewal application.

Water Supply

Based on a declaration from the U.S. Bureau of Reclamation, as of January 1, 2026, Arizona's supply of Colorado River water will remain subject to a Tier 1 shortage. This is the fourth year since 2022 that a Tier 1 shortage has been declared. The most severe shortage to have been declared was a Tier 2a shortage in 2023. A Tier 1 shortage reduces Arizona's share of the Colorado River water by 18 percent or 512,000-acre feet; however, due to in-state conservation measures, Arizona has kept more Colorado River water in Lake Mead than is required by the shortage. Tier 1 reductions are largely felt by central Arizona's agricultural users, mainly in Pinal County. Assured supplies of water are important for APS's generating plants. At this time, a Tier 1 shortage does not materially impact water supplies used by APS's fleet of generation resources. As drought conditions across the southwestern U.S. region continue to worsen, APS will monitor water availability necessary for continued Company operations and, as necessary, implement measures to mitigate risks associated with future Colorado River shortage declarations.

Conflicting claims to drought-impacted surface water in the southwestern United States have resulted in disputes and numerous court actions. The General Stream Adjudication allows the state to issue a final priority determination on claims to surface water rights. There are three General Stream Adjudications near APS generating stations that may impact surface water or groundwater supplies that are adjacent to surface water streams.

San Juan River Adjudication. Both groundwater and surface water in areas important to APS's operations have been the subject of inquiries, claims, and legal proceedings, which will require a number of years to resolve. APS is one of numerous parties in a proceeding, filed March 13, 1975, before the Eleventh Judicial District Court in New Mexico to adjudicate rights to a stream system from which water for Four Corners is derived. An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for an agreed upon cost, sufficient water from its allocation to offset the loss.

Gila River Adjudication. A summons served on APS in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987, in an action pending in Arizona Superior Court. Palo Verde is located within the geographic area subject to the summons. APS's rights and the rights of the other Palo Verde participants to the use of groundwater and effluent at Palo Verde are potentially at issue in this adjudication. As operating agent of Palo Verde, APS filed claims that dispute the court's jurisdiction over the Palo Verde participants' groundwater rights and their contractual rights to effluent relating to Palo Verde. Alternatively, APS seeks confirmation of such rights. Several of APS's other power plants are also located within the geographic area subject to the summons, including a number of gas-fired power plants located within Maricopa and Pinal Counties. In November 1999, the Arizona Supreme Court issued a decision confirming that certain groundwater rights may be available to the federal government and Indian tribes. In addition, in September 2000, the Arizona Supreme Court issued a decision affirming the lower court's criteria for resolving groundwater claims. Litigation on both of these issues has continued in the trial court. In December 2005, APS and other parties filed a petition with the Arizona Supreme Court requesting interlocutory review of a September 2005 trial court order regarding procedures for determining whether groundwater pumping is affecting surface water rights. The Arizona Supreme Court denied the petition in May 2007, and the trial court is now proceeding with implementation of its 2005 order. No trial date concerning APS's water rights claims has been set in this matter.

At this time, the lower court proceedings in the Gila River adjudication are in the process of determining the specific hydro-geologic testing protocols for determining which groundwater wells located outside of the subflow zone of the Gila River should be subject to the adjudication court's jurisdiction. A hearing to determine this jurisdictional test question was held in March 2018 in front of a special master, and a draft decision based on the evidence heard during that hearing was issued on May 17, 2018. The decision of the special master, which was finalized on November 14, 2018, accepts the proposed hydro-geologic testing protocols supported by APS and other industrial users of groundwater. A further ruling affirming this decision by the trial court judge overseeing the adjudication was issued on July 8, 2022. Further proceedings have been initiated to determine the specific hydro-geologic testing protocols for subflow depletion determinations. The determinations made in this final stage of the proceedings may ultimately govern the adjudication of rights for parties, such as APS, which rely on groundwater extraction to support their industrial operations. APS cannot predict the outcome of these proceedings.

Little Colorado River Adjudication. APS has filed claims to water in the Little Colorado River Watershed in Arizona in an action pending in the Apache County, Arizona, Superior Court, which was originally filed on September 5, 1985. APS's groundwater resource utilized at Cholla is within the geographic area subject to the adjudication and, therefore, is potentially at issue in the case. APS's claims dispute the court's jurisdiction over its groundwater rights. Alternatively, APS seeks confirmation of such rights. No trial or pretrial proceedings have been scheduled for adjudication of APS's water right claims. The adjudication court is currently conducting a trial of federal reserved water right claims asserted by the Hopi Tribe and by the United States as trustee for the Tribe. In addition, the adjudication court has established a schedule for consideration of separate federal reserved water right claims asserted by the

Navajo Nation and by the United States as trustee for the Nation. There is no established timeframe within which the adjudication court is expected to issue a final determination of water rights for the Hopi Tribe and the Navajo Nation, and any such final determination is likely to occur multiple years in the future.

Although the above matters remain subject to further evaluation, APS does not expect that the described litigation will have a material adverse impact on its financial condition, results of operations, or cash flows.

Human Capital

The Company's success depends on a strong human capital strategy including attracting, developing, and retaining a high-performing workforce. We are committed to fostering a safe, inclusive, and engaging work environment that empowers all employees to reach their full potential. Key human capital measures and objectives that drive our business strategy include employee safety, employee development, strong company culture based upon the APS Promise, strong talent pipelines, extensive learning and development focus, and succession planning.

The table below presents the employee count as of December 31, 2025:

	Principal Executive Office Address	Year of Formation	Approximate Number of Employees at December 31, 2025	
Pinnacle West	400 North Fifth Street Phoenix, AZ 85004	1985	94	
APS	400 North Fifth Street P.O. Box 53999 Phoenix, AZ 85072-3999	1920	6,516	(a)
El Dorado	400 North Fifth Street Phoenix, AZ 85004	1983	—	
PNW Power	400 North Fifth Street Phoenix, AZ 85004	2023	—	
Total			6,610	

(a) Includes employees at jointly-owned generating facilities (approximately 2,400 employees) for which APS serves as the generating facility manager.

Approximately 1,120 APS employees are union employees represented by International Brotherhood of Electrical Workers ("IBEW"). On September 25, 2023, the IBEW membership ratified a new collective bargaining agreement ("CBA") with APS. The new CBA became effective in October 2023 and has a duration of three years until April 1, 2026 and thereafter until either party gives notice of desire for change, amendment, or termination. On August 23, 2024, 27 IT Communications Field Specialists joined the existing bargaining unit represented by IBEW. APS and IBEW Local 387 continue to bargain in good faith to reach an agreement with the IT Communications Field Specialist group. Additionally, IBEW Local 387, in accordance with the CBA, has provided APS with a 60-day notice of request to bargain, as the amendable date of the current CBA is April 1, 2026.

Culture and Engagement

The APS Promise anchors our commitment to our customers, community, and each other. The Promise explains our purpose, vision, and mission and the principles and behaviors that will empower us to achieve our strategic goals. It represents the opportunity to build on our cultural strengths and develop new behaviors to enable our future success. In 2025, we refreshed our Promise to ensure its relevancy and alignment with our strategic direction. We updated our Mission to ensure alignment with our top priorities—safety, reliability, and affordability. We also updated some of our shared behaviors to make sure they reflect who we are as a company and how we will succeed today and into the future. The APS Promise continues to be reinforced and integrated throughout our Company programs and messaging.

The **APS Promise**

Our Purpose
As Arizona stewards, we do what is right for the people and prosperity of our state.

Our Vision
Create a sustainable energy future for Arizona.

Our Mission
Serve our customers with safe, reliable and affordable energy.

Our **Principles**

Design For **Tomorrow**	Empower **Each Other**	Succeed **Together**
Innovate with courage	Build trust	Unite as one team
Navigate risk	Embrace diverse perspectives	Own the outcome
Learn and improve	Challenge respectfully	Pursue excellence

We evaluate our success in building this culture in part through annual and quarterly employee engagement surveys, including our Employee Experience Index, which measures key aspects of engagement such as recognition, career development, and organizational pride. In 2025, we had 83% participation in these surveys, and our Employee Experience Index was 86%. These surveys enable us to compare our performance to industry benchmarks and identify areas for improvement.

Based on the survey results, we encourage business units and managers to take action. For example, past surveys have led to initiatives that we believe improved communication, removed job success obstacles, increased employee access to leadership, and enhanced meeting efficiency.

We actively seek feedback from new hires to further refine the employee onboarding experience. Our cross-functional Employee Engagement Council plays a key role in driving improvements, particularly in employee engagement and recognition.

We believe that belonging matters. We recognize that differences of identities, perspectives, and experiences are a key driver for our success. Inclusion at the Company involves embracing the unique perspectives of each employee. Examples of the Company's efforts in this space include the following:

- Support for 11 employee networking groups to encourage employees to develop themselves, advance in their chosen field, and join a community; and
- Continuous listening practices to provide employees with opportunities to be heard.

Employee Safety

Our work and our decisions are anchored in safety – safety is the foundation of everything we do, and employee safety is our paramount responsibility as an employer. We develop practices and programs that ensure employees have safe and secure workplaces that allow them to perform at the highest levels. We utilize preventative programs like APS Moves to help keep our workforce healthy and prepare them to perform tasks safely. Our comprehensive safety programs and our focus on human and organizational performance and injury case management contribute significantly to our strong safety performance. As we continue to improve our safety performance, our ultimate goal remains serious injury reduction. We believe our employees are empowered to speak up when there are better or safer ways of doing business. Safety committees operate in organizations throughout the Company, providing opportunities for employees to positively impact their local safety cultures and performance. Additionally, the Company's executive safety committee helps ensure strong safety governance and operational integration across the enterprise and employee-led learning teams help ensure that lessons learned from close calls and other safety incidents are shared for the benefit of employees across the enterprise.

Talent Strategy and Pipeline Development

Attracting and developing a highly skilled workforce is critical to our success. To this end, our talent strategy prioritizes the following:

- *Commitment to Growth and Development*: We provide a wide range of professional development opportunities to support a modern learning culture, including on-demand learning, learning events, leadership academies, rotational programs, mentoring, industry certifications, and loaned executive programs. We also run dedicated programs for individual contributors, new leaders, and high-potential managers.
- *Robust Talent Pipelines*: Our pipeline strategy focuses on attracting and developing early- and mid-career talent for critical energy sector positions, including lineworkers, substation electricians, cybersecurity specialists, engineers, and nuclear power plant operators and technicians. We achieve this through an array of programs, including craft apprenticeships, engineering and rotational programs, and internships.
- *Strategic Partnerships*: We leverage partnerships with colleges, universities, vocational schools, and the Department of Defense SkillBridge program to access a wide pool of qualified candidates, including transitioning military personnel.
- *Innovation in Talent Acquisition*: In recent years, APS has expanded its internship programs to include interns in APS's Forestry and Water Resource Departments, and Palo Verde expanded its programs to include nuclear operations.
- *Leadership and Talent Philosophy*. In 2025, APS introduced a new Leadership Model and Talent Philosophy to provide clarity and focus on how our leaders can shape a culture where people and performance excel. APS's Leadership Model outlines key traits and skills that

bring APS's Promise to life with actionable behaviors at each leadership level. APS's Talent Philosophy provides guidance for leaders to define a shared set of standards as it relates to managing talent. These standards are focused on Behaviors, Transparency, Differentiation, Leadership Commitment and Performance to ensure consistency, reduce biases, and align leadership.

These initiatives contribute to a high-performing and engaged workforce that supports the long-term success of our Company.

Succession Planning

Succession planning is critical to ensuring the long-term success of our Company. We have a robust process for identifying and developing high-potential leaders to fill key executive and other critical roles. This involves regularly reviewing and updating succession plans for key positions, identifying and assessing potential successors, and providing targeted development opportunities such as mentoring, coaching, and challenging rotational assignments. We also evaluate leadership potential through assessments, performance reviews, and 360-degree feedback. The addition of our Leadership Model will also serve as guidance to help us identify and develop talent throughout our leadership pipeline, ensuring we use the same standards throughout the enterprise. We collaborate with senior leadership to build a pipeline of qualified internal and external candidates and continuously adapt our succession planning process to meet evolving business needs and industry trends.

Total Rewards Strategy

Recognizing that our employees are the foundation of our innovation, growth, and success, we have developed a comprehensive Total Rewards strategy to attract, engage, and retain a high-performing workforce. Our Total Rewards program encompasses a comprehensive suite of offerings, including competitive compensation, a robust benefits package, retirement savings plans, professional development opportunities, recognition programs, and a focus on employee well-being. This holistic approach aims to (1) attract and retain top talent by offering a competitive and attractive compensation and benefits package, (2) support employee well-being by promoting a healthy lifestyle, work-life balance and providing resources to support employee physical, mental, and financial well-being, (3) foster employee engagement and motivation through recognition programs, professional development opportunities, and a strong emphasis on career growth, and (4) enhance employee satisfaction by creating a rewarding and fulfilling work experience for all employees. We continuously evaluate and refine our Total Rewards program to ensure it remains competitive, relevant, and responsive to the evolving needs and expectations of our employees.

BUSINESS OF OTHER SUBSIDIARIES

PNW Power

PNW Power holds certain investments and assets that were previously held by BCE, a former subsidiary of Pinnacle West that was sold in 2024. PNW Power's investments include TransCanyon, a 50/50 joint venture that was formed in 2014 with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. TransCanyon is pursuing independent electric transmission opportunities within the 11 U.S. states that comprise the Western Interconnection, excluding opportunities related to transmission service that would otherwise be provided under the tariffs of the retail service territories of the TransCanyon partners' utility affiliates. These opportunities include the proposed 500-kV Cross-Tie transmission project, which includes a 214-mile transmission line connecting Utah and Nevada that is intended to help improve grid reliability and relieve congestion on other transmission lines. On December 18, 2025, the Department of Interior Bureau of Land Management issued a Record of Decision permitting the development of Cross-Tie Project, which became non-appealable in late January 2026.

PNW Power's investments also include minority ownership positions in two wind farms operated by Tenaska Energy, Inc. and Tenaska Energy Holdings, LLC, the 242 MW Clear Creek and the 250 MW Nobles 2 wind farms. Clear Creek achieved commercial operation in May 2020; however, in the fourth quarter of 2022, PNW Power's equity method investment was fully impaired. Nobles 2 achieved commercial operation in December 2020. Both wind farms deliver power under long-term PPAs. PNW Power indirectly owns 9.9% of Clear Creek and 5.1% of Nobles 2.

El Dorado

El Dorado owns debt investments and minority interests in several energy-related investments and Arizona community-based ventures. In particular, El Dorado has committed to and/or holds the following:

- $25 million investment in the Energy Impact Partners fund, of which approximately $20 million has been funded as of December 31, 2025. Energy Impact Partners is an organization that focuses on fostering innovation and supporting the transformation of the utility industry.

- $25 million investment in AZ-VC Fund I, LLC (formerly invisionAZ Fund) ("AZ-VC"), of which approximately $16 million has been funded as of December 31, 2025. AZ-VC is a fund focused on analyzing, investing, managing, and otherwise dealing with investments in privately-held early stage and emerging growth technology companies and businesses primarily based in Arizona, or based in other jurisdictions and having existing or potential strategic or economic ties to companies or other interests in Arizona.

- $7.5 million investment in Westly Seed Fund, of which approximately $2 million has been funded as of December 31, 2025. Westly Seed Fund is focused on supporting entrepreneurs involved in the energy, mobility, building, and industrial sectors.

- Equity investment in SAI Advanced Power Solutions, Inc. ("SAI"), a private corporation that manufactures electrical switchgear equipment used by data centers. El Dorado accounts for this investment under the equity method and has an investment carrying value of approximately $21 million as of December 31, 2025.

The remainder of these investment commitments will be contributed by El Dorado as each investment fund selects and makes investments.

WHERE TO FIND MORE INFORMATION

We use our website (*www.pinnaclewest.com*) as a channel of distribution for material Company information. The following filings are available free of charge on our website as soon as reasonably practicable after they are electronically filed with, or furnished to, the SEC: Annual Reports on Form 10-K, definitive proxy statements for our annual shareholder meetings, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to those reports. The SEC maintains a website that contains reports, proxy and information statements and other information regarding issuers, such as the Company, that file electronically with the SEC. The address of that website is www.sec.gov. Our board and committee charters, Code of Ethics for Financial Executives, Code of Ethics and Business Practices, and other corporate governance information is also available on the Pinnacle West website. Pinnacle West will post any amendments to the Code of Ethics for Financial Executives and Code of Ethics and Business Practices, and any waivers that are required to be disclosed by the rules of either the SEC or the New York Stock Exchange on its website. The information on Pinnacle West's website is not incorporated by reference into this report.

You can request a copy of these documents, excluding exhibits, by contacting Pinnacle West at the following address: Pinnacle West Capital Corporation, Office of the Corporate Secretary, Mail Station 8602, P.O. Box 53999, Phoenix, Arizona 85072-3999 (telephone 602-250-3011).

ITEM 1A. RISK FACTORS

In addition to the factors affecting specific business operations identified in the description of these operations contained elsewhere in this report, set forth below are risks and uncertainties that could affect our financial results. Unless otherwise indicated or the context otherwise requires, the following risks and uncertainties apply to Pinnacle West and its subsidiaries, including APS.

REGULATORY RISKS

Our financial condition depends upon APS's ability to recover costs in a timely manner from customers through regulated rates and otherwise execute its business strategy.

APS is subject to comprehensive regulation by several federal, state and local regulatory agencies that significantly influence its business, liquidity and results of operations and its ability to fully recover costs from utility customers in a timely manner. The ACC regulates APS's retail electric rates and FERC regulates rates for wholesale power sales and transmission services. The profitability of APS is affected by the rates it may charge and the timeliness of recovering costs incurred through its rates and adjustor recovery mechanisms. Consequently, our financial condition and results of operations are dependent upon the satisfactory resolution of any APS rate proceedings, adjustor recovery and ancillary matters which may come before the ACC and FERC, including in some cases how court challenges to these regulatory decisions are resolved. Arizona, like certain other states, has a statute that allows the ACC to reopen prior decisions and modify otherwise final orders under certain circumstances. Additionally, given that APS is subject to oversight by several regulatory agencies, a resolution by one may not foreclose potential actions by others for similar or related matters. See Note 14.

The ACC must also approve APS's issuance of equity and debt securities and any significant transfer or encumbrance of APS property used to provide retail electric service and must approve or receive prior notification of certain transactions between us, APS, and our respective affiliates, including the infusion of equity into APS. Decisions made by the ACC or FERC could have a material adverse impact on our financial condition, results of operations, or cash flows.

APS's ability to conduct its business operations and avoid negative operational and financial impacts depends in part upon compliance with federal, state and local laws, judicial decisions, statutes, regulations and ACC requirements, which may be revised from time to time by legislative or other action, and obtaining and maintaining certain regulatory permits, approvals, and certificates.

APS must comply in good faith with all applicable statutes, regulations, rules, tariffs, executive orders and orders of agencies that regulate APS's business, including FERC, NRC, EPA, the ACC, and state and local governmental agencies. These laws, regulations, and agencies regulate many aspects of APS's utility operations, including safety and performance, emissions, siting and construction of facilities, labor and employment, customer service and the rates that APS can charge retail and wholesale customers. Failure to comply can subject APS to, among other things, fines and penalties. For example, under the Energy Policy Act of 2005, FERC can impose penalties (approximately $1.2 million per day per violation) for failure to comply with mandatory electric reliability standards. APS is also required to have numerous permits, approvals and certificates from these agencies. APS believes the necessary permits, approvals and certificates have been obtained for its existing operations and that APS's business is conducted in accordance with applicable laws in all material respects.

Changes in laws or regulations that govern APS, new interpretations of laws and regulations, or the imposition of new or revised laws or regulations could have an adverse impact on the manner in which we operate our business and our results of operations. In particular, new or revised laws or interpretations of existing laws or regulations may impact or call into question the ACC's permissive regulatory authority, which may result in uncertainty as to jurisdictional authority within our state, and uncertainty as to whether ACC decisions will be binding or challenged by other agencies or bodies asserting jurisdiction. We are unable to predict the impact on our business and operating results from any pending or future regulatory or legislative rulemaking.

The operation of APS's nuclear power plant exposes it to substantial regulatory oversight and potentially significant liabilities and capital expenditures.

The NRC has broad authority under federal law to impose safety-related, security-related and other licensing requirements for the operation of nuclear generating facilities. Events at nuclear facilities of other operators or impacting the industry generally may lead the NRC to impose additional requirements and regulations on all nuclear generating facilities, including Palo Verde. In the event of noncompliance with its requirements, the NRC has the authority to impose a progressively increased inspection regime that could ultimately result in the shut-down of a unit or civil penalties, or both, depending upon the NRC's assessment of the severity of the situation, until compliance is achieved. The increased costs resulting from penalties, a heightened level of scrutiny and implementation of plans to achieve compliance with NRC requirements may adversely affect APS's financial condition, results of operations and cash flows.

APS is subject to numerous environmental laws and regulations, and changes in, or liabilities under, existing or new laws or regulations may increase APS's cost of operations or impact its business plans.

APS is, or may become, subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of conventional pollutants and GHGs, water quality, discharges of wastewater and waste streams originating from fly ash and bottom ash handling facilities, solid waste, hazardous waste, and coal combustion products, which consist of bottom ash, fly ash, and air pollution control wastes. These laws and regulations can result in increased capital, operating, and other costs, particularly with regard to enforcement efforts focused on power plant emissions obligations. They could also impact the overall business environment in Arizona and affect APS's customer and sales growth rates. Additionally, these laws and regulations generally require APS to obtain and comply with a wide variety of environmental licenses, permits, and other approvals. If there is a delay or failure to obtain any required environmental regulatory approval, or if APS fails to obtain, maintain, or comply with any such approval, operations at affected facilities could be suspended or subject to additional expenses. In addition, failure to comply with applicable environmental laws and regulations could result in civil liability as a result of government enforcement actions or private claims or criminal penalties. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. APS cannot predict the outcome (financial or operational) of any related litigation that may arise.

APS cannot assure that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to it. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs incurred by APS are not fully recoverable from APS's customers, could have a material adverse effect on its financial condition, results of operations, or cash flows. Due to current or potential future regulations or legislation coupled with trends in natural gas and coal prices, or other clean energy rules or initiatives, the economics or feasibility of continuing to own certain resources, particularly coal facilities, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement but cannot predict whether it would obtain such recovery. Such regulations may also act as a deterrent to future customer growth or create additional costs for existing customers, potentially slowing APS's customer growth.

See "Business of Arizona Public Service Company — Environmental Matters" in Part I, Item 1 as well as Note 14 for examples of environmental laws and regulations and matters that could affect APS's financial condition, results of operations and cash flows.

APS faces potential financial risks resulting from climate change litigation and legislative and regulatory efforts to limit GHG emissions, as well as physical and operational risks related to climate effects.

Concern over climate change has led to significant legislative and regulatory efforts to limit carbon dioxide, which is a major byproduct of the combustion of fossil fuel, and other GHG emissions.

Potential Financial Risks — GHG Regulation, the Clean Power Plan and Potential Litigation. On April 25, 2024, EPA issued new GHG emission standards for power plants. These new standards are focused on limiting power plant GHG emissions through control mechanisms that can be implemented at individual power plant facilities. The new regulations are currently being challenged in federal court and, in 2025, EPA proposed a rule to repeal these GHG emission standards. Additionally, the Trump administration has stated that it intends to reverse or substantially revise these standards. See "Business of Arizona Public Service Company — Environmental Matters — Climate Change" in Part I, Item 1 for more information.

Depending on the outcome of carbon emission rulemaking under the Clean Air Act targeting new and existing power plants, the utility industry may become subject to more stringent and expansive regulations. Depending on the means of compliance with federal emission performance standards, the electric utility industry may be forced to incur substantial costs necessary to achieve compliance. In addition, we anticipate that such regulations will be challenged in federal court prior to their implementation. Depending on the outcome of such judicial review, the utility industry may face alternative efforts from private parties seeking to establish alternative GHG emission limitations from power plants. Alternative GHG emission limitations may arise from litigation under either federal or state common laws or citizen suit provisions of federal environmental statutes that attempt to force federal agency rulemaking or impose direct facility emission limitations. Such lawsuits may also seek damages from harm alleged to have resulted from power plant GHG emissions.

Physical and Operational Risks. Weather extremes such as drought and high temperature variations are common occurrences in the southwestern United States' desert area, and these are risks that APS considers in the normal course of business in the engineering and construction of its electric system. Large increases in ambient temperatures could require evaluation of certain materials used within its system and may represent a greater challenge. Limitations on water supplies necessary to operate electric generation infrastructure could arise from prolonged drought and shortage declarations associated with key surface water resources. As part of conducting its business, APS recognizes that the southwestern United States is particularly susceptible to the risks posed by climate change, which over time is projected to exacerbate high temperature extremes and prolong drought in the area where APS conducts its business.

Co-owners of our jointly owned generation and transmission facilities may have unaligned goals and positions due to the effects of legislation, regulations, economic conditions, or changes in our industry, which could have a significant impact on our ability to continue operations of such facilities.

APS owns certain of its power plants and transmission facilities jointly with other owners, with varying ownership interests in such facilities. Changes in the nature of our industry and the economic viability of certain plants and facilities, including impacts resulting from types and availability of other resources, fuel costs, legislation, and regulation, together with timing considerations related to the expiration of leases or other agreements for such facilities, could result in unaligned positions among co-owners. Differences in the co-owners' willingness or ability to continue their participation could lead to the eventual shut down of units or facilities and uncertainty related to the resulting cost recovery of such assets. See Note 8 for a discussion of the Navajo Plant and Cholla retirements and the related risks associated with APS's continued recovery of its remaining investment in the plant.

Deregulation or restructuring of the electric industry and other factors may result in increased competition, which could have a significant adverse impact on APS's business and its results of operations.

Modification of the ACC's retail electric competition rules or other efforts of deregulation and other factors, such as customers installing behind the meter technologies or large customers developing large, utility scale generation projects to serve their energy needs, may result increased competition, which could have a significant adverse impact on APS's business and results of operations.

OPERATIONAL RISKS

APS's results of operations can be adversely affected by various factors impacting demand for electricity.

Weather Conditions. Weather conditions directly influence the demand for electricity and affect the price of energy commodities. Electric power demand is generally a seasonal business. In Arizona, demand for power peaks during the hot summer months, with market prices also peaking at that time. As a result, APS's overall operating results fluctuate substantially on a seasonal basis. In addition, APS has historically sold less power, and consequently earned less income, when weather conditions are milder. As a result, unusually mild weather could diminish APS's financial condition, results of operations, or cash flows.

Apart from the impact on electricity demand, weather conditions related to prolonged high temperatures or extreme heat events present operational challenges. In the southwestern United States, where APS conducts its business, the effects of climate change are projected to increase the overall average temperature, lead to more extreme temperature events, and exacerbate prolonged drought conditions leading to the declining availability of water resources. Extreme heat events and rising temperatures are projected to reduce the generation capacity of thermal-power plants and decrease the efficiency of the transmission grid. These operational risks related to rising temperatures and extreme heat events could affect APS's financial condition, results of operations, or cash flows.

Higher temperatures may decrease the snowpack, which might result in lowered soil moisture and an increased threat of wildfires. Wildfires could threaten APS's communities and electric transmission lines and facilities. Any damage caused as a result of wildfires could negatively impact APS's financial condition, results of operations, or cash flows. In addition, the decrease in snowpack can also lead to reduced water supplies in the areas where APS relies upon non-renewable water resources to supply cooling and process water for electricity generation. Prolonged and extreme drought conditions can also affect APS's long-term ability to access the water resources necessary for thermal electricity generation operations. Reductions in the availability of water for power plant cooling could negatively impact APS's financial condition, results of operations, or cash flows.

Effects of Energy Conservation Measures and Distributed Energy Resources. APS customers participate in energy efficiency and conservation programs and other DSM efforts, which in turn impact the demand for electricity. APS must also meet certain distributed renewable energy requirements. A portion of APS's total renewable energy requirement must be met with an increasing percentage of distributed renewable energy resources (generally, small-scale renewable technologies located on customers' properties). The distributed renewable energy requirement is 30% of the applicable RES requirement for 2012 and subsequent years (APS was granted a waiver of this requirement in its 2026 RES Implementation Plan). Customer participation in distributed renewable energy programs would result in lower demand since customers would be meeting some of their own energy needs.

In addition to these rules and requirements, energy efficiency technologies and distributed energy resources continue to evolve, which may have similar impacts on the demand for electricity. Reduced demand due to these energy efficiency requirements, distributed energy requirements and other emerging technologies, unless substantially offset through ratemaking mechanisms, could have a material adverse impact on APS's financial condition, results of operations and cash flows.

Actual and Projected Customer and Sales Growth. Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as macroeconomic conditions, current and future economic, regulatory, business, and other conditions, such as the Arizona housing market, customer growth, usage patterns and energy conservation, slower ramp-up of and/or fewer large data centers and manufacturing facilities, slower than expected commercial and industrial expansions, impacts of energy efficiency programs and growth in DG, responses to retail price changes, changes in regulatory standards, and impacts of new and existing laws and regulations, including environmental laws and regulations. Based on past experience, a 1% variation in our annual residential and small commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $25 million, and a 1% variation in our annual large commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $7 million.

Recent industry trends and projections of load growth reflect significant demand from data centers to support AI as well as onshoring of manufacturing, such as advanced semiconductor manufacturing. These data centers and large manufacturers may locate their operations within service territories other than our own. If they do choose to locate within our service territory, we may not be able to provide sufficient electric service within the time period they require due to capital or other constraints. APS may need to accelerate development plans of the related generation and transmission facilities to serve these potential customers, which may necessitate alternative financing structures, such as the novel subscription model we are pursuing in an effort to ensure growth pays for growth and reduce cross-subsidization of customer classes, as well as ACC approval. APS may not be able to secure facilities or regulatory approval to support these customers in a timely manner. Additionally, the future demand from these customers may not be realized to the extent currently projected and significant uncertainties exist regarding the future energy demand associated with data centers and AI. The difficulty in forecasting these demands and the additional risk of these arrangements could lead to stranded costs and other effects that could have material adverse impacts on APS's financial condition, results of operations, and cash flows.

The impact of wildfires could negatively affect APS's results of operations.

Wildfires have the potential to affect communities within APS's service territory and the surrounding areas, as well as APS's vast network of electric transmission and distribution lines and facilities. The potential likelihood and severity of wildfires has increased due to many of the same weather and climate change impacts existing in Arizona as those that led to catastrophic wildfires in other states. The continued expansion of the wildland urban interface has also increased wildfire risk to surrounding communities. Extreme weather events such as severe storms and strong wind gusts may also increase the likelihood of a wildfire in our service territory. APS has a Comprehensive Wildfire Mitigation Plan ("CWMP") that employs various strategies designed to prevent, mitigate, and respond to wildfire risks. APS's CWMP includes vegetation management and clearing protocols, operational measures and a public safety power shut off program ("PSPS") on certain feeders, among other practices. However, APS's fire mitigation efforts may be insufficient to prevent wildfires in APS's expansive service territory and surrounding areas and could result in claims alleging damages due to the use, non-use, timing, or effectiveness of such measures. In addition, APS could be sued regardless of fault for damages incurred as a result of wildfires and may not be able to recover all or a substantial portion of any such damages or costs from insurance or through rates. In addition, we could also experience credit rating downgrades, reputational harm, volatility in the market for our common stock, and significant financial distress upon the occurrence of a wildfire event. Furthermore, any damage caused to our assets, loss of service to our customers, or liability imposed as a result of wildfires could negatively impact APS's financial condition, results of operations, or cash flows.

The operation of power generation facilities and transmission systems involves risks that could result in reduced output or unscheduled outages or could otherwise significantly impact APS's results of operations.

The operation of power generation, transmission and distribution facilities involves certain risks, including the risk of breakdown or failure of equipment, fuel interruption, and performance below expected levels of output or efficiency. Unscheduled outages, including extensions of scheduled outages due to mechanical failures or other complications, occur from time to time and are an inherent risk of APS's business. Because our transmission facilities are interconnected with those of third parties, the operation of our facilities could be adversely affected by unexpected or uncontrollable events occurring on the larger transmission power grid, and the operation or failure of our facilities could adversely affect the operations of others. Concerns over the physical security of these assets could include damage to certain of our facilities due to vandalism or other deliberate acts that could lead to outages or other adverse effects. If APS's facilities operate below expectations, especially during its peak season, it may lose revenue or incur additional expenses, including increased purchased power expenses.

Additionally, as APS's transmission infrastructure ages and its transmission system needs to grow to support growth in our territory and in the Southwest, it will need to replace and expand certain portions of its transmission infrastructure, which requires significant investment of capital. Risks related to the timely completion of, and costs associated with, these projects may be exacerbated by a constrained supply chain limiting the availability of necessary parts and materials as well as APS's use, in some cases, of older, obsolete, or unsupported equipment. Certain replacements and expansions of the transmission infrastructure will also require the acquisition or renewal of land leases, easements, or other rights-of-way that may require approvals from landowners, including individuals, government agencies, and, at times, tribal nations. APS is unable to predict the outcomes of any pending or future required approvals, including any related costs, which could be significant. If APS is unable to successfully manage the replacement and expansion of its transmission infrastructure, it could face increased equipment failures, power quality challenges, reputational impact, and financial loss.

The inability to successfully develop, acquire or operate generation and transmission facilities to meet future resource needs and load forecasts in accordance with reliability requirements and other new or evolving standards and regulations could adversely impact our business.

Potential changes in regulatory standards, impacts of new and existing laws and regulations, including environmental laws and regulations, and the need to obtain various regulatory approvals create uncertainty surrounding our current and future generation portfolio. Current laws and regulations as well as changes to those laws and regulations, including via judicial decisions and executive orders, create strategic challenges in acquiring an appropriate generation portfolio and fuel diversification mix. APS is required by the ACC to meet certain energy resource portfolio requirements, including those related to renewables development and energy efficiency measures, in addition to specific competitive resource procurement requirements. Operating, maintaining, and developing our generation and other assets requires significant capital expenditures and operations and maintenance costs that may be difficult to maintain at adequate levels while maintaining reliability. The development and operation of these facilities is subject to other risks, including those related to financing, siting, permitting, new and evolving technology, extreme weather events, workforce issues, cybersecurity attacks, supply chain constraints for key equipment and critical spare parts, overreliance on or the existence of a small number of suppliers, access to fuel, and the construction of sufficient transmission capacity to support these facilities among others. Macroeconomic and geopolitical factors may also impact our ability to procure the generation and other equipment we need to meet customer demand. APS needs to develop or acquire new generation and other facilities, potentially modernize existing facilities, and/or contract for additional capacity in order to meet future resource needs and load forecasts. APS's inability to do so could have a material adverse impact on our business and results of operations.

In expressing concerns about the environmental and climate-related impacts from continued extraction, transportation, delivery and combustion of fossil fuels, environmental advocacy groups and other third parties have in recent years undertaken greater efforts to oppose the permitting, construction, and operation of fossil fuel infrastructure projects. These efforts may increase in scope and frequency depending on a number of variables, including the future course of Federal environmental regulation and the increasing financial resources devoted to these opposition activities. APS cannot predict the effect that any such opposition may have on our ability to develop, construct, and operate fossil fuel infrastructure projects in the future.

In August 2025, APS announced an update to its clean energy goal from zero-carbon to carbon-neutral by 2050. APS's ability to successfully execute its clean energy goal is dependent upon a number of external factors, some of which include supportive national and state energy policies, a supportive regulatory environment, sales and customer growth, the development, deployment and advancement of clean energy technologies, adequate supply chain for generation resources, and continued access to capital markets.

The lack of access to sufficient supplies of water could have a material adverse impact on APS's business and results of operations.

Assured supplies of water are important for APS's generating plants. Water in the southwestern United States is limited, and various parties have made conflicting claims regarding the right to access and use such limited supplies of water. Both groundwater and surface water in areas important to the operation of APS's generating plants have been and are the subject of inquiries, claims and legal proceedings. In addition, the region in which APS's power plants are located suffers from prolonged drought conditions, which could potentially affect the plants' water supplies. Climate change is projected to exacerbate such drought conditions. Colorado River water supplies for Arizona are subject to shortage declarations that substantially limit the quantity of water available to the state. Due to stressed surface water and groundwater supplies, there is focus on the increased use of treated effluent to supplement statewide water supplies, which could increase competition for the treated effluent that some APS generating plants rely on. APS's inability to access sufficient supplies of water, along with that of its customers, could have a material adverse impact on our business and results of operations.

We are subject to risk related to cybersecurity, IT systems, and unauthorized access to our systems that could adversely affect our business and financial condition.

We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. In the regular course of our business, we handle a range of sensitive security, customer, and business systems information. There appears to be an increasing level of activity, sophistication, and maturity of threat actors, including from both nation-state and non-nation state actors, that seek to exploit potential vulnerabilities in the electric utility industry and wish to disrupt the U.S. bulk power system, our information technology systems, generation (including our Palo Verde nuclear facility), transmission and distribution facilities, and other infrastructure facilities and systems and physical assets. We have been and could be the target of attacks, and the aforementioned systems are critical areas of cyber protection for us.

We rely extensively on IT systems, networks, and services, including internet sites, data hosting and processing facilities, and other hardware, software and technical applications and platforms. Some of these systems are managed, hosted, provided, or used by third parties to assist in conducting our business. Malicious actors may attack vendors to disrupt the services these vendors provide to us or to use those vendors as a cyber conduit to attack us. As more third parties are involved in the operation of our business, there is a risk the confidentiality, integrity, privacy, or security of data held by, or accessible to, third parties may be compromised. In addition to the involvement of third parties and the associated security risks, we also face risks when integrating new IT systems, such as those associated with costs, operational efficiency, and security compliance. Our IT systems introduce layers of execution complexity and resource risks across the entire organization.

If a significant cybersecurity event or breach were to occur, we may not be able to fulfill critical business functions and we could (i) experience property damage, disruptions to our business, theft of or unauthorized access to customer, employee, financial or system operation information or other information; (ii) experience loss of revenue or incur significant costs for repair, remediation and breach notification, and increased capital and operating costs to implement increased security measures; and (iii) be subject to increased regulation, litigation and reputational damage. If such disruptions or breaches are not detected quickly, their effects could be compounded or could delay our response or the effectiveness of our response and ability to limit our exposure to potential liability. These types of events as well as the impacts of integrating new IT systems could also require significant management attention and resources and could have a material adverse impact on our financial condition, results of operations, or cash flows.

We develop and maintain systems and processes aimed at detecting and preventing information and cybersecurity incidents which require significant investment, maintenance, and ongoing monitoring and updating as technologies and regulatory requirements change. These systems and processes may be insufficient to mitigate the possibility of cybersecurity incidents, malicious social engineering, fraudulent or other malicious activities, and human error or malfeasance in the safeguarding of our data.

We are subject to laws and rules issued by multiple government agencies concerning safeguarding and maintaining the confidentiality of our security, customer information and business information. One of these agencies, NERC, has issued comprehensive regulations and standards surrounding the security of bulk power systems and is continually in the process of developing updated and additional requirements with which the utility industry must comply. The NRC also has issued regulations and standards related to the protection of critical digital assets at commercial nuclear power plants. The increasing promulgation of NERC and NRC rules and standards will increase our compliance costs and our exposure to the potential risk of violations of the standards. Experiencing a cybersecurity incident could cause us to be non-compliant with applicable laws and regulations, such as those promulgated by NERC and the NRC, privacy laws, or contracts that require us to securely maintain confidential data, causing us to incur costs related to legal claims or proceedings and regulatory fines or penalties.

The risk of these system-related events and security breaches occurring continues to intensify. We have experienced, and expect to continue to experience, threats and attempted intrusions to our information technology systems and we could experience such threats and attempted intrusions to our operational control systems. To date, we do not believe we have experienced a material breach or disruption to our network or information systems or our service operations. We may not be able to anticipate and prevent all cyberattacks or information security breaches, and our ongoing investments in security resources, talent, and business practices may not be effective against all threat actors.

We maintain cyber insurance to provide coverage for a portion of the losses and damages that may result from a security breach of our information technology systems, but such insurance is subject to a number of exclusions and may not cover the total loss or damage caused by a breach. Coverage for cybersecurity events continues to evolve as the industry matures. In the future, adequate insurance may not be available at rates that we believe are reasonable, and the costs of responding to and recovering from a cyber incident may not be covered by insurance or recoverable in rates.

There are inherent risks in the ownership and operation of nuclear facilities, such as environmental, health, fuel supply, spent fuel disposal, regulatory and financial risks and the risk of terrorist attack that could adversely affect our business and financial condition.

APS has an ownership interest in and operates on behalf of a group of participants, Palo Verde, which is the largest nuclear electric generating facility in the western United States. Palo Verde constitutes approximately 18% of APS's owned and leased generation capacity. Palo Verde is subject to environmental, health and financial risks, such as the ability to obtain adequate supplies of nuclear fuel; the ability to dispose of spent nuclear fuel; the ability to maintain adequate reserves for decommissioning; potential liabilities arising out of the operation of these facilities; the costs of securing the facilities against possible terrorist attacks; and unscheduled outages due to equipment and other problems. APS maintains nuclear decommissioning trust funds and external insurance coverage to minimize its financial exposure to some of these risks; however, it is possible that damages could exceed the amount of insurance coverage. APS may be required under federal law to pay up to $144.9 million (but not more than $21.6 million per year) of liabilities arising out of a nuclear incident not only at Palo Verde, but at any other nuclear power plant in the United States. In addition, APS is subject to retrospective premium adjustments under its nuclear property insurance policies with NEIL for approximately $24.2 million if NEIL's losses in any policy year exceed accumulated funds and if the retrospective premium assessment is declared by NEIL's Board of Directors. Although APS has no reason to anticipate a serious nuclear incident at Palo Verde, if an incident did occur, it could materially and adversely affect our results of operations and 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 and to promulgate new regulations that could require significant capital expenditures and/or increase operating costs.

Changes in technology could create challenges for APS's existing business.

Alternative energy technologies that produce power or reduce power consumption or emissions are being developed and commercialized, including renewable technologies such as photovoltaic (solar) cells, customer-sited generation, energy storage (batteries) and efficiency technologies. Advances in technology and equipment/appliance efficiency could reduce the demand for supply from conventional generation, including carbon-free nuclear generation, and increase the complexity of managing APS's information technology and power system operations, which could adversely affect APS's business.

Customer-sited alternative energy technologies present challenges to APS's operations due to misalignment with APS's existing operational needs. When these resources lack "dispatchability" and other elements of utility-side control, they are considered "unmanaged" resources. The cumulative effect of such unmanaged resources results in added complexity for APS's system management.

APS continues to pursue and implement advanced grid technologies, including transmission and distribution system technologies and digital meters enabling two-way communications between the utility and its customers. Many of the products and processes resulting from these and other alternative technologies, including energy storage technologies, have not yet been widely used or tested on a long-term basis, and their use on large-scale systems is not as established or mature as APS's existing technologies and equipment. The implementation of new and additional technologies adds complexity to our information technology and operational technology systems, which could require additional infrastructure and resources. APS's strategy, including the timing of such strategy, in adopting new technologies, such as artificial intelligence, could also adversely impact APS's business. For example, if APS fails to strategically implement artificial intelligence, it could miss the opportunity for cost savings, face increasing costs on legacy systems, insufficiently integrate internal and external data sets, or invest in low data quality, risk misusing artificial intelligence, impact employee satisfaction with its implementation of or failure to implement artificial intelligence and other technologies. Widespread installation and acceptance of new technologies could also enable the entry of new market participants, such as technology companies, into the interface between APS and its customers and could have other unpredictable effects on APS's traditional business model.

Deployment of renewable energy technologies is expected to continue across the western states and result in a larger portion of the overall energy production coming from these sources. These trends, which have benefited from historical and continuing government support for certain technologies, have the potential to put downward pressure on wholesale power prices throughout the western states which could make APS's existing generating facilities less economical and impact their operational patterns and long-term viability.

We are subject to employee workforce factors that could adversely affect our business and financial condition.

Like many companies in the electric utility industry, our workforce is maturing, with approximately 26.1% of employees eligible to retire by the end of 2030. Although we have undertaken efforts to recruit, train and develop new employees, we face increased competition for talent. We are subject to other employee workforce factors, such as the availability and retention of qualified personnel and the need to negotiate collective bargaining agreements with union employees. These or other employee workforce factors could negatively impact our business, financial condition, or results of operations.

FINANCIAL RISKS

A downgrade of our credit ratings could materially and adversely affect our business, financial condition, and results of operations.

Our current ratings are set forth in “Liquidity and Capital Resources — Credit Ratings” in Part II, Item 7. We cannot be sure that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any downgrade or withdrawal could adversely affect the market price of Pinnacle West’s and APS’s securities, limit our access to capital and increase our borrowing costs, which would adversely impact our financial results. We could be required to pay a higher interest rate for future financings, and our potential pool of investors and funding sources could decrease. In addition, borrowing costs under our existing credit facilities depend on our credit ratings. A downgrade could also require us to provide additional support in the form of letters of credit or cash or other collateral to various counterparties. If our short-term ratings were to be lowered, it could severely limit access to the commercial paper market. We note that the ratings from rating agencies are not recommendations to buy, sell or hold our securities and that each rating should be evaluated independently of any other rating.

Investment performance, changing interest rates, new rules or regulations and other economic, social, and political factors could decrease the value of our benefit plan assets, nuclear decommissioning trust funds and other special use funds or increase the valuation of our related obligations, resulting in significant additional funding requirements.

We have significant pension plan and other postretirement benefits plan obligations to our employees and retirees, and legal obligations to fund our pension trust and nuclear decommissioning trusts for Palo Verde. We hold and invest substantial assets in these trusts that are designed to provide funds to pay for certain of these obligations as they arise. Declines in market values of the fixed income and equity securities held in these trusts may increase our funding requirements for the related trusts. Additionally, the valuation of liabilities related to our pension plan and other postretirement benefit plans are impacted by a discount rate, which is the interest rate used to discount future pension and other postretirement benefit obligations. Changes in interest rates impact the discount rate and valuation of the plan liabilities, and may result in increases in pension and other postretirement benefit costs, cash contributions, regulatory assets, and charges to OCI. Changes in demographics, including increased number of retirements or changes in life expectancy and changes in other actuarial assumptions, may also result in similar impacts. The minimum contributions required under these plans are impacted by federal legislation and related regulations. Increasing liabilities or otherwise increasing funding requirements under these plans, resulting from adverse changes in legislation or otherwise, could result in significant cash funding obligations that could have a material impact on our financial condition, results of operations, or cash flows.

We recover most of the pension and other postretirement benefit expense and all of the currently estimated nuclear decommissioning costs in our regulated rates. Any inability to fully recover these costs in a timely manner could have a material negative impact on our financial condition, results of operations, or cash flows.

Our cash flow depends on the performance of APS and its ability to make distributions.

We derive essentially all of our revenues and earnings from our wholly-owned subsidiary, APS. Accordingly, our cash flow and our ability to pay dividends on our common stock is dependent upon the earnings and cash flows of APS and its distributions to us. APS is a separate and distinct legal entity and has no obligation to make distributions to us.

APS’s financing agreements may restrict its ability to pay dividends, make distributions or otherwise transfer funds to us. In addition, an ACC financing order requires APS to maintain a common equity ratio of at least 40% and does not allow APS to pay common dividends if the payment would reduce its common equity below that threshold. The common equity ratio, as defined in the ACC order, is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt.

We may not have adequate insurance coverage for liabilities.

The operation of power generation, transmission and distribution facilities involves hazardous activities. We may become exposed to significant liabilities for which we may not have adequate insurance coverage or risk mitigation. Additionally, through our captive insurance cell, we take certain insurance risk on our business, such as certain wildfire coverage, excess property insurance, and excess employment practice liability. We maintain an amount of insurance protection that we believe is customary, but there can be no assurance it will be sufficient or effective in light of all circumstances, hazards or liabilities to which we may be subject. Our insurance does not cover every potential risk associated with our operations. Adequate coverage at reasonable rates is not always obtainable. We cannot provide assurance that insurance coverage will continue to be available in the amounts or on terms similar to our current policies. These issues could have a material adverse effect on our business, results or operations, and financial condition.

Pinnacle West's ability to meet its debt service obligations could be adversely affected because its debt securities are structurally subordinated to the debt securities and other obligations of its subsidiaries.

Because Pinnacle West is structured as a holding company, all existing and future debt and other liabilities of its subsidiaries will be effectively senior in right of payment to its own debt securities. The assets and cash flows of our subsidiaries will be available, in the first instance, to service their own debt and other obligations. Our ability to have the benefit of their cash flows, particularly in the case of any insolvency or financial distress affecting our subsidiaries, would arise only through our equity ownership interests in our subsidiaries and only after their creditors have been satisfied.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.

APS's operations include managing market risks related to commodity prices. APS is exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and coal to the extent that unhedged positions exist. We have established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange traded futures and over-the-counter ("OTC") forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity and natural gas. The changes in market value of such contracts have a high correlation to price changes in the hedged commodity. To the extent that commodity markets are illiquid, we may not be able to execute our risk management strategies, which could result in greater unhedged positions than we would prefer at a given time and financial losses that negatively impact our results of operations.

The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act") contains measures aimed at increasing the transparency and stability of the over-the-counter derivative markets and preventing excessive speculation. The Dodd-Frank Act could restrict, among other things, trading positions in the energy futures markets, require different collateral or settlement positions, or increase regulatory reporting over derivative positions. Based on the provisions included in the Dodd-Frank Act and the implementation of regulations, these changes could, among other things, impact our ability to hedge commodity price and interest rate risk or increase the costs associated with our hedging programs.

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We use a risk management process to assess and monitor the financial exposure of all counterparties. Despite the fact that the majority of APS's trading counterparties are rated as investment grade by the rating agencies, there is still a possibility that one or more of these companies could default, which could result in a material adverse impact on our earnings for a given period.

Financial market disruptions or new rules or regulations may increase our financing costs or limit our access to various financial markets, which may adversely affect our liquidity and our ability to implement our financial strategy.

Pinnacle West and APS rely on access to credit markets as a significant source of liquidity and the capital markets for capital requirements not satisfied by cash flow from our operations. We believe that we will maintain sufficient access to these financial markets. However, certain market disruptions or revisions to rules or regulations may cause our cost of borrowing to increase generally, and/or otherwise adversely affect our ability to access these financial markets.

In addition, the credit commitments of our lenders under our bank facilities may not be satisfied or continued beyond current commitment periods for a variety of reasons, including new rules and regulations, changes to the internal policies of our lenders, periods of financial distress or liquidity issues affecting our lenders or financial markets, which could materially adversely affect the adequacy of our liquidity sources and/or the cost of maintaining these sources.

Changes in economic conditions, monetary policy, fiscal policy, financial regulation, rating agency treatment and/or other factors could result in higher interest rates, which would increase interest expense on our existing variable rate debt and new debt we expect to issue in the future, and thus increase the cost and/or reduce the amount of funds available to us for our current plans.

Additionally, an increase in our leverage, whether as a result of these factors or otherwise, could adversely affect us by:

- causing a downgrade of our credit ratings;
- increasing the cost of future debt financing and refinancing;
- increasing our vulnerability to adverse economic and industry conditions; and
- requiring us to dedicate an increased portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future investment in our business or other purposes.

GENERAL RISKS

Proposals to change policy in Arizona or other states made through ballot initiatives or referenda may increase the Company's cost of operations or impact its business plans.

In Arizona and other states, a person or organization may file a ballot initiative or referendum with the Arizona Secretary of State or other applicable state agency and, if a sufficient number of verifiable signatures are presented, the initiative or referendum may be placed on the ballot for the public to vote on the matter. Ballot initiatives and referenda may relate to any matter, including policy and regulation related to the electric industry, and may change statutes or the state constitution in ways that could impact Arizona utility customers, the Arizona economy, and the Company. Some ballot initiatives and referenda are drafted in an unclear manner and their potential industry and economic impact can be subject to varied and conflicting interpretations. We may oppose certain initiatives or referenda (including those that could result in negative impacts to our customers, the state, or the Company) via the electoral process, litigation, traditional legislative mechanisms, agency rulemaking or otherwise, which could result in significant costs to the Company. The passage of certain initiatives or referenda could result in laws and regulations that impact our business plans and have a material adverse impact on our financial condition, results of operations, or cash flows.

General economic conditions could materially affect our business, financial condition, and results of operations.

General economic factors that are beyond the Company's control impact the Company's forecasts and actual performance. These factors include interest rates; recession; inflation; stagflation; deflation; supply chain constraints; unemployment trends; sanctions, trade restrictions, military interventions and the threat or possibility of war; terrorism or other global or national unrest; and political or financial instability. In particular, in recent years the United States' economy experienced a substantial rise in the inflation rate and more recently in 2025 the Trump administration has implemented tariffs and discussed additional tariffs, which would further increase costs. The Company is currently evaluating the impact of the recent U.S. Supreme Court's decision regarding the validity of certain tariffs previously imposed under the International Emergency Powers Act, including whether any or all of the tariffs will be eligible for a refund as well as the potential for replacement tariffs under separate statutory authorities. Additionally, supply chains have been impacted and could be further impacted by inflation, tariffs, and other sociopolitical factors, resulting in equipment delays and increased costs. Any failure to recover these potential increased costs through our rates could have a material adverse impact on our financial condition, results of operations, or cash flows.

The market price of our common stock may be volatile.

The market price of our common stock could be subject to significant fluctuations in response to factors such as the following, some of which are beyond our control:

- variations in our quarterly operating results;
- operating results that vary from the expectations of management, securities analysts, and investors;
- changes in expectations as to future financial performance, including financial estimates by securities analysts and investors;
- developments generally affecting industries in which we operate;
- announcements by us or our competitors of significant contracts, acquisitions, joint marketing relationships, joint ventures, or capital commitments;
- announcements by third parties of significant claims or proceedings against us;
- favorable or adverse regulatory or legislative developments;
- our dividend policy;
- change in our management;
- future sales by the Company of equity or equity-linked securities; and
- general domestic and international economic conditions.

In addition, the stock market in general has experienced volatility that has often been unrelated to the operating performance of a particular company. These broad market fluctuations may adversely affect the market price of our common stock.

Certain provisions of our articles of incorporation and bylaws and of Arizona law make it difficult for shareholders to change the composition of our board and may discourage takeover attempts.

These provisions, which could preclude our shareholders from receiving a change of control premium, include the following:

- restrictions on our ability to engage in a wide range of "business combination" transactions with an "interested shareholder" (generally, any person who beneficially owns 10% or more of our outstanding voting power, or any of our affiliates or associates who beneficially owned 10% or more of our outstanding voting power at any time during the prior three years) or any affiliate or associate of an interested shareholder, unless specific conditions are met;
- anti-greenmail provisions of Arizona law and our bylaws that prohibit us from purchasing shares of our voting stock from beneficial owners of more than 5% of our outstanding shares unless specified conditions are satisfied;
- the ability of the Board of Directors to increase the size of and fill vacancies on the Board of Directors, whether resulting from such increase, or from death, resignation, disqualification or otherwise;
- the ability of our Board of Directors to issue additional shares of common stock and shares of preferred stock and to determine the price and, with respect to preferred stock, the other terms, including preferences and voting rights, of those shares without shareholder approval;
- restrictions that limit the rights of our shareholders to call a special meeting of shareholders; and
- restrictions regarding the rights of our shareholders to nominate directors or to submit proposals to be considered at shareholder meetings.

While these provisions may have the effect of encouraging persons seeking to acquire control of us to negotiate with our Board of Directors, they could enable the Board of Directors to hinder or frustrate a transaction that some, or a majority, of our shareholders might believe to be in their best interests and, in that case, may prevent or discourage attempts to remove and replace incumbent directors.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Neither Pinnacle West nor APS has received written comments regarding its periodic or current reports from the SEC staff that were issued 180 days or more preceding the end of its 2025 fiscal year and that remain unresolved.

ITEM 1C. CYBERSECURITY

The Company prioritizes and maintains a high level of commitment to responsible and secure cybersecurity practices given the critical nature of its services and the potential consequences of a successful cyber-attack on the Company and the electric grid. A successful cyber-attack could have far-reaching consequences, from compromising the integrity of sensitive data to disrupting power supply. To that end, the Company implements a robust risk management, strategy, and governance regime aimed at implementing controls to identify, mitigate, remediate, and communicate cyber threats at appropriate levels within the organization.

APS's cybersecurity group (the "Cybersecurity Group") is comprised of cybersecurity analysts, engineers, architects, and others, led by the Director of Cybersecurity, who reports to APS's Vice President, Operations Support. The Director of Cybersecurity has more than twenty years of experience in information technology and cybersecurity roles, with more than ten of those years at the Company. The Director of Cybersecurity also holds cybersecurity certifications from multiple certifying bodies and is active in utility cybersecurity professional organizations. The Cybersecurity Group has day-to-day responsibility for safeguarding the Company's critical assets and assessing, identifying, and managing material risks from cybersecurity threats.

In fulfilling its responsibility, the Cybersecurity Group manages formal documented internal processes such as risk management and vulnerability scanning, as well as other processes, such as assessing threat intelligence, that include outside partners. Intelligence sharing comes from industry sources such as the Electricity Information Sharing and Analysis Center, government sources, as well as commercially purchased information sources. The Cybersecurity Group also engages third parties for assessments and audits of its systems periodically and as needed. Such assessments and audits may include, among other things, pre-production evaluation of technologies, overall program assessments, and compliance program assessments including audits by our regulators.

Depending on the products and services provided and the potential for data exchange and technology risk, we may require vendors and service providers to pass APS's vendor risk management program, which sets forth security and data protection requirements, as a condition to doing or continuing to do business with us. For contracts with vendors that will handle or have access to certain sensitive data, APS requires contractual provisions setting forth cybersecurity controls, vulnerability management, secure development practices, and other security and data protection requirements. A subset of vendors that meet a predetermined risk profile due to strategic relationships, technology risk, or other factors is continually monitored by a third-party risk management service, and the Company annually reviews independent assessments of these vendors.

The Cybersecurity Group also has documented processes for identifying, responding to, and internally escalating cybersecurity incidents to management and the Board of Directors. Once an incident meets certain criteria, the Company's Cybersecurity Incident Command or, in the case of a potentially severe threat that could impact the entire Company, the Corporate Emergency Operations Center is activated and formal response procedures are followed to address the incident. The Cybersecurity Group has a formal incident response plan that details response and escalation procedures, including activation of a Cybersecurity Disclosure Committee, consisting of the Chief Financial Officer and the General Counsel, to assess an incident's materiality with input as needed from the Director of Cybersecurity, Chief Accounting Officer, Chief Information Officer, and others, including outside advisors.

Cybersecurity risk management has been integrated into the Company's overall enterprise risk management program (the "Enterprise Risk Management Program") through policies and processes that implement a risk management framework designed to identify, manage, and monitor business unit risks throughout the organization. The Enterprise Risk Management Program is overseen by an executive committee (the "Executive Risk Committee"), which meets at least quarterly and is comprised of members holding executive leadership positions in the Company, including the Chairman, President, and Chief Executive Officer, and other Executive and Senior Vice Presidents, and is chaired and sponsored by the Chief Financial Officer. Every year, as a part of the Enterprise Risk Management Program, risks affecting the Company are identified. Cybersecurity is among the enterprise risks assessed annually and was identified as a top risk in 2025. The applicable subject matter experts brief the Company's Board of Directors on the status of all top enterprise risks at least once per year. Finally, the Nuclear and Operating Committee of the Company's Board of Directors provides ultimate oversight of cybersecurity risk and also receives briefings in-person or virtually at least twice per year from the Cybersecurity Group, and notable audit findings relating to cybersecurity are aggregated and provided to the Board of Directors' Audit Committee.

To date, we do not believe there have been any previous cybersecurity incidents that have materially affected or are reasonably likely to materially affect Pinnacle West or APS. However, there is no assurance that will continue to be the case. If a significant cybersecurity event or incident were to occur, our ability to fulfill our critical business functions could be materially impacted, which could materially adversely affect our results of operations and financial conditions. See the risk factor entitled, "We are subject to cybersecurity risks and risks of unauthorized access to our systems that could adversely affect our business and financial condition" in Part I, Item 1A—Risk Factors for more information.

ITEM 2. PROPERTIES

Generation Facilities

APS's portfolio of owned generating facilities in commercial operation as of the date of this report is provided in the table below:

Name	No. of Units	% Owned (a)	Principal Fuels Used	Primary Dispatch Type	Owned Capacity (MW)
Nuclear:					
Palo Verde (b)	3	29.1 %	Uranium	Base Load	1,146
Total Nuclear					1,146
Steam:					
Four Corners 4, 5 (c)	2	63 %	Coal	Base Load	970
Total Steam					970
Combined Cycle:					
Redhawk	2		Gas	Load Following	1,140
West Phoenix	5		Gas	Load Following	874
Total Combined Cycle					2,014
Combustion Turbine:					
Ocotillo	7		Gas	Peaking	630
Saguaro	3		Gas	Peaking	189
Douglas	1		Oil	Peaking	18
Sundance	12		Gas	Peaking	520
West Phoenix	2		Gas	Peaking	114
Yucca 1, 2, 3, 5, 6	5		Gas	Peaking	183
Yucca 4	1		Oil	Peaking	54
Total Combustion Turbine					1,708
Solar:					
Cotton Center			Solar	As Available	17
Hyder I			Solar	As Available	17
Paloma			Solar	As Available	17
Chino Valley			Solar	As Available	20
Gila Bend			Solar	As Available	36
Hyder II			Solar	As Available	14
Foothills			Solar	As Available	38
Luke AFB			Solar	As Available	11
Desert Star			Solar	As Available	10
Red Rock			Solar	As Available	44
Agave Solar			Solar	As Available	150
APS Owned Distributed Energy			Solar	As Available	41
Multiple facilities			Solar	As Available	4
Total Solar					419
Total Capacity					6,257

(a) 100% unless otherwise noted.
(b) APS's 29.1% ownership in Palo Verde includes leased interests and is the largest capacity interest of all the participants. See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Generation Facilities — Nuclear" in Part I, Item 1 for details regarding leased interests in Palo Verde. The other participants are Salt River Project, SCE, El Paso Electric Company, Public Service Company of New Mexico, Southern California Public Power Authority, and Los Angeles Department of Water and Power.
(c) The other participants are Salt River Project (10%), Public Service Company of New Mexico (13%), Tucson Electric Power Company (7%) and NTEC (7%). The plant is operated by APS.

Energy Storage Facilities

APS's portfolio of owned energy storage facilities in commercial operation as of the date of this report is provided in the table below. Capacity amounts are approximate and represent the maximum designed MW the site can provide for three hours, unless noted otherwise.

	Location	Owned Capacity
BESS:		
Paloma	Gila Bend, AZ	17
Cotton Center	Gila Bend, AZ	17
Hyder I	Hyder, AZ	16
Chino Valley (a)	Chino Valley, AZ	19
Hyder II	Hyder, AZ	14
Foothills	Yuma, AZ	35
Gila Bend	Gila Bend, AZ	32
Desert Star	Buckeye, AZ	10
Red Rock (a)	Red Rock, AZ	41
Total Energy Storage		**201**

(a) Capacity amounts represent the maximum designed MW the site can provide for four hours.

See "Business of Arizona Public Service Company" in Part I, Item 1 for a map detailing the location of APS's major power plants and principal transmission lines.

Transmission and Distribution Facilities

Current Facilities. As of January 22, 2026, APS's transmission facilities consist of approximately 5,939 pole miles of overhead lines and approximately 86 miles of underground lines, 5,792 miles of which are located in Arizona. APS's distribution facilities consist of approximately 11,321 miles of overhead lines and approximately 24,425 miles of underground primary cable (21,301 when excluding abandoned conductor), all of which are located in Arizona. APS also owns and maintains 477 substations, including both transmission and distribution yards. APS shares ownership of some of its transmission facilities with other companies.

The following table shows APS's jointly-owned interests in those transmission facilities recorded on the Consolidated Balance Sheets at December 31, 2025:

	Percent Owned (Weighted-Average)
Arizona Nuclear Power Project 500kV System	33.1 %
Navajo Southern System	25.1 %
Palo Verde — Yuma 500kV System	16.1 %
Four Corners Switchyards	56.9 %
Phoenix — Mead System	17.5 %
Palo Verde — Rudd 500kV System	50.0 %
Morgan — Pinnacle Peak System	63.2 %
Round Valley System	50.0 %
Palo Verde — Morgan System	87.5 %
Hassayampa — North Gila System	80.0 %
Cholla 500kV Switchyard	85.7 %
Saguaro 500kV Switchyard	60.0 %
Kyrene — Knox System	50.0 %

Expansion. Each year, APS prepares and files with the ACC a Ten-Year Transmission Plan. In APS's 2026 Ten-Year Transmission Plan, APS projects it will develop 263 miles of new transmission lines over the next 10 years. Additionally, APS plans to upgrade 725 miles of existing transmission lines over the same horizon. The 2026 Ten-Year Plan includes critical transmission projects that represent significant upgrades to our transmission system. These upgrade projects, along with other projects included in the 2026 Ten Year Transmission Plan, are designed to support growing energy needs, strengthen reliability, and allow for the connection of new resources.

Plant and Transmission Line Leases and Rights-of-Way on Indian Lands

The Navajo Plant and Four Corners are located on land held under leases from the Navajo Nation and also under rights-of-way from the federal government. The Navajo Plant ceased operations in November 2019. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017, that allowed for decommissioning activities to begin after the plant ceased operations.

APS, on behalf of the Four Corners participants, negotiated amendments to the Four Corners facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Generation Facilities — Coal-Fueled Generating Facilities — Four Corners" in Part I, Item 1 for additional information about the Four Corners right-of-way and lease matters.

Certain portions of APS's transmission lines are located on Indian lands pursuant to rights-of-way that are effective for specified periods. Some of these rights-of-way have expired and renewal applications have not yet been acted upon by the appropriate Indian tribes or federal agencies. Other rights expire at various times in the future and renewal action by the applicable tribe or federal agencies will be required at that time. In recent negotiations, certain of the affected Indian tribes have required payments substantially in excess of historical amounts paid in the past for such rights-of-way. The ultimate cost of renewal of certain of the rights-of-way for transmission lines is therefore uncertain.

ITEM 3. LEGAL PROCEEDINGS

See “Business of Arizona Public Service Company — Environmental Matters” in Part I, Item 1 with regard to pending or threatened litigation and other disputes.

See Note 8 for ACC and FERC-related matters.

See Note 14 for information regarding environmental matters, Superfund–related matters and other disputes.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

Pinnacle West's executive officers are elected no less often than annually and may be removed by the Board of Directors, or in certain cases also by the Human Resources Committee, at any time. The executive officers, their ages at February 25, 2026, current positions and principal occupations for the past five years are as follows:

Name	Age	Position	Period
Theodore N. Geisler	47	Chairman of the Board, Chief Executive Officer and President of Pinnacle West and APS	2025-Present
		President of APS; Director, Pinnacle West and APS Boards of Directors	2024-2025
		President of APS	2022-2024
		Senior Vice President and Chief Financial Officer of Pinnacle West and APS	2020-2022
Shirley A. Baum	52	Senior Vice President, Corporate Secretary and General Counsel of Pinnacle West and APS	2026-Present
		Senior Vice President and General Counsel of Pinnacle West and APS	2025-2026
		Vice President of Law of Pinnacle West and APS	2022-2025
		Deputy General Counsel of Pinnacle West	2019-2022
Christopher R. Bauer	50	Vice President and Treasurer of Pinnacle West and APS	2024-Present
		Director, Corporate Finance and Assistant Treasurer of Duke Energy Corporation	2021-2024
		Director, Credit and Capital Markets of Duke Energy Corporation	2017-2021
Elizabeth A. Blankenship	54	Vice President, Controller and Chief Accounting Officer of Pinnacle West and APS	2019-Present
Andrew D. Cooper	47	Senior Vice President and Chief Financial Officer of Pinnacle West and APS	2022-Present
		Vice President and Treasurer of Pinnacle West and APS	2020-2022
Jose L. Esparza	51	Senior Vice President, Public Policy of APS	2022-Present
		Vice President, Regulatory of APS	2022
		Officer and Senior Vice President, Customer Engagement and Information Technology of Southwest Gas	2019-2021
Adam C. Heflin	62	Executive Vice President and Chief Nuclear Officer, Palo Verde, of APS	2022-Present
		Chief Executive Officer of Wolf Creek Nuclear Operating Corporation	2014-2019
Jacob Tetlow	53	Executive Vice President and Chief Operating Officer of APS	2024-Present
		Executive Vice President, Operations of APS	2021-2024
		Senior Vice President, Non-Nuclear Operations of APS	2020-2021

PART II

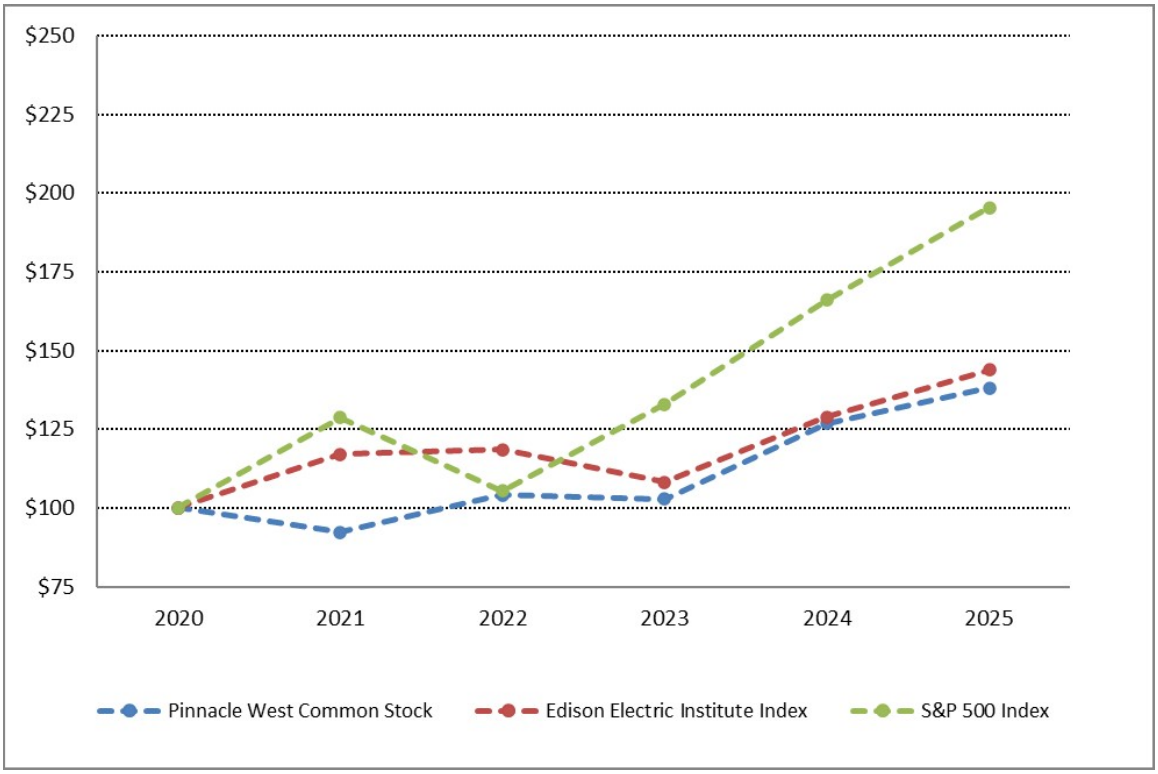
ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Pinnacle West's common stock is publicly held and is traded on the New York Stock Exchange under stock symbol PNW. At the close of business on February 19, 2026, Pinnacle West's common stock was held of record by approximately 12,926 shareholders.

APS's common stock is wholly-owned by Pinnacle West and is not listed for trading on any stock exchange. The sole holder of APS's common stock, Pinnacle West, is entitled to dividends when and as declared out of legally available funds. At December 31, 2025, APS did not have any outstanding preferred stock.

Stock Performance Chart

This graph compares the cumulative total shareholder return on Pinnacle West's common stock during the five years ended December 31, 2025, to the cumulative total returns on the S&P 500 Index and the Edison Electric Institute Index. The comparison assumes that $100 was invested on December 31, 2020, in Pinnacle West's common stock and in each of the indices shown and that all of the dividends were reinvested.



Company/Index	Year Ended December 31, 2020	2021	2022	2023	2024	2025
Pinnacle West Common Stock	$100	$92	$104	$103	$127	$138
Edison Electric Institute Index	$100	$117	$118	$108	$129	$144
S&P 500 Index	$100	$129	$105	$133	$166	$195

ITEM 6. [RESERVED]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The following discussion should be read in conjunction with Pinnacle West's Consolidated Financial Statements and APS's Consolidated Financial Statements and the related Notes that appear in Item 8 of this report. This discussion provides a comparison of the 2025 results with 2024 results. For the discussion of 2024 compared to 2023, see Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations of Pinnacle West Capital Corporation's Annual Report on Form 10-K for the year ended December 31, 2024, which specific discussion is incorporated herein by reference. For information on factors that may cause our actual future results to differ from those we currently seek or anticipate, see "Forward-Looking Statements" at the front of this report and "Risk Factors" in Item 1A.

OVERVIEW

Business Overview

Pinnacle West is an investor-owned electric utility holding company based in Phoenix, Arizona with consolidated assets of approximately $30 billion. We derive essentially all of our revenues and earnings from our principal subsidiary, APS. Since 1886, APS and its affiliates have provided energy and energy-related products to people and businesses throughout Arizona. APS is Arizona's largest and longest-serving electric company and generates safe, affordable and reliable electricity for approximately 1.4 million retail customers in 11 of Arizona's 15 counties. APS is also the operator and co-owner of Palo Verde — a primary source of electricity for the southwestern United States. Our other active subsidiaries are El Dorado and PNW Power.

Strategic Overview

Our vision is to create a sustainable energy future for Arizona. Our mission is to serve customers with safe, reliable, and affordable energy. We are committed to delivering operational excellence at the lowest cost possible while aspiring to lower carbon emissions over time.

Reliable

As energy demand in Arizona continues to grow, we remain committed to delivering reliable service to our customers. We have a goal of achieving top quartile reliability as compared to peers. Key elements to delivering reliable service include resource and transmission planning to secure resource adequacy, planning and procuring resources to ensure sufficient reserve margins, distribution automation and resiliency investments, predictive and preventative maintenance programs, seasonal readiness programs, emergency preparedness, and securing a reliable supply chain. Securing a reliable grid requires ongoing infrastructure investments in addition to investments to support new customer growth.

Balanced Energy Mix. APS strives to procure a balanced energy mix, and we believe this provides the greatest reliability at the lowest cost possible while increasing resiliency. We achieve reliability, in part, through a blend of dispatchable resources, such as natural gas and battery storage, that can provide energy when intermittent resources, such as wind and solar, are unavailable. APS regularly evaluates the best mix of resources based on a changing operating environment, including changes in generation technology, economics, and policy impacts.

Additional natural gas capacity is necessary to support reliable service and meet increasing energy needs. However, existing natural gas pipelines into Arizona are currently 100% committed. As a result, in July 2025, APS executed a gas transportation precedent agreement to secure a long-term supply of natural gas. The new pipeline is expected to be operational by late 2029 and will be owned and operated by a third-party. See Note 14 for more information. APS also plans to add up to 2,000 MW of flexible natural gas generation to its portfolio, designed to help meet the growing around-the-clock energy needs in Arizona. This generation is expected to serve existing customers and business-as-usual growth through our competitive ASRFP process as well as a new subscription model for large load customers, like data centers and large manufacturers. This subscription model is a commercial construct designed to ensure growth pays for growth while protecting affordability for other customers.

Palo Verde, one of the nation's largest carbon-free energy resources, serves as a foundational part of APS's resource portfolio. The plant is a critical asset to the Southwest, generating more than 32 million MWh – enough power for roughly 3.4 million households, or approximately 8.5 million people. Its continued operation is important to a carbon-neutral future for Arizona and the region, as a reliable, continuous, affordable resource and as a large contributor to the local economy. APS owns or leases 29.1% of Units 1, 2, and 3 Palo Verde. In June 2025, APS entered into agreements to purchase two of the three leased interests in Unit 2. The two subject leased interests represented approximately 7% or 94 MW of Unit 2. The transaction closed in September 2025, leaving one remaining lease for approximately 5.2% of Unit 2 that expires in 2033. See Note 12 for more information. APS's rate case application filed in 2025 (the "2025 Rate Case") includes pro forma adjustments to account for these acquisitions. APS continues to evaluate and pursue options for reliably serving growing customer energy needs and demand.

Wildfire Efforts. Wildfire safety remains a critical focus for APS and other utilities. APS has increased investment in fire mitigation efforts to clear defensible space around its infrastructure, continue ongoing system upgrades, build partnerships with government entities and first responders, and educate customers and communities. APS also increased spend on mitigating the risk associated with trees that could cause hazards, resulting in more of these trees being removed before they could cause outages or wildfires. These programs contribute to customer reliability, responsible forest management and safe communities. With wildfire events in Hawaii, California, and across North America over the last few years, APS has been devoting and intends to continue to devote substantial efforts to analyzing and developing enhancements to its systems and processes to mitigate fire risk within its service territory and communities, including by hardening our infrastructure, deploying new technologies where appropriate, increasing our awareness, implementing operational changes, and enhancing our wildfire response capabilities.

APS uses fire modeling software to identify and calculate risk and target future system improvement investments such as fire-resistant pole wrapping, wood to steel pole conversions, and additional remote-controllable field devices like reclosers and switches. In 2024, APS began installing a system of artificial intelligence-based fire sensing cameras with the ability to detect and alert on fire ignitions. These alerts are sent both to APS and fire response dispatch centers to speed fire response in APS's service territory regardless of the cause of the fire. APS also implemented a public safety power shutoff ("PSPS") program on certain feeders that began in the 2024 fire season, leveraging the additional real-time analysis provided by the modeling software. APS has educated and will continue education outreach to customers and communities that may potentially be impacted by the PSPS program.

APS was selected by DOE's Grid Deployment Office ("GDO") to receive up to $70 million in federal money for fire mitigation and grid infrastructure projects. This funding is part of the GDO's Grid Resilience and Innovation Partnership Program and is contingent on APS negotiating and executing final grant agreements with GDO. Additionally, on May 12, 2025, Arizona Governor Hobbs signed into law a bill that requires Arizona electric utilities to develop and seek approval for wildfire mitigation plans and defines the standard of care with respect to wildfire-related claims by reference to such plans. APS continues to evaluate policy and regulatory options, as well as insurance programs, to mitigate the impact of wildfire events.

Affordable

We are committed to keeping bills as low as possible for our customers while maintaining high levels of reliability. Inflation has dramatically impacted the cost of goods and services in recent years as shown by the Consumer Price Index for All Urban Consumers ("CPI-U"), which from 2018 through 2024 rose nationally 24.9% and 32.1% in Phoenix. Despite this, APS's average residential rates remained well-below those inflation figures, rising 16.2% for the same period according to the U.S. Energy Information Administration. Inflation has moderated from earlier highs, with CPI-U rising 2.7% nationally and 2.2% in Phoenix over the 12 months ended December 2025. As a result of increased tariffs and supply chain constraints, APS amended several of its agreements from its ASRFP issued in 2023 to mitigate these cost impacts. However, APS remains cautious of potential price increases as a result of current and proposed tariffs, which could lead to higher costs and supply chain constraints, while also monitoring the outcome of the recent U.S. Supreme Court's decision regarding the validity of certain tariffs.

APS's customer affordability initiative includes internal opportunities, such as training and mentoring employees on identifying efficiency opportunities; maintaining inventory to take advantage of lower pricing and avoid expediting fees; entering into long-term contracts to hedge against price volatility, which has allowed APS to mitigate against procurement spend on critical items such as transformers; and implementing automation technologies to enhance efficiencies and increase data-oriented decision making. The customer affordability initiative also includes external opportunities, including a portfolio of customer programs designed to help customers reduce and manage their bills. In the 2025 Rate Case, APS is also seeking to reduce cross-subsidization of customer classes and ensure that growth pays for growth by requesting modifications to its cost allocation methodologies. APS continues to seek opportunities to streamline its business processes, mitigate cost increases, increase employee retention, and improve customer satisfaction.

APS's IRP and competitive ASRFP processes serve important roles in providing reliable and affordable energy to APS's customers. The IRP process helps identify the amount and type of resources required to reliably meet customer needs, while the ASRFP process seeks to meet those needs in a competitive manner based on cost, ability to meet system requirements, and commercial viability.

APS has seen increasing demand from large load customers in recent years. In the 2025 Rate Case, APS requested adjustments to rate designs and modification of cost allocation methodologies to ensure growth pays for growth. In line with the 2025 Rate Case, APS has developed a subscription model it believes will allow for these large load customers to fund the incremental infrastructure needed to serve them through long-term contracts where they cover capital costs and assume development risks, accelerating their path to service and ensuring those infrastructure costs are borne by those customers rather than residential or small business customers.

There are also external opportunities that allow APS to deliver more affordable energy to customers, such as APS's participation in western energy markets and programs. APS participated in market design and tariff development of Markets+, a day-ahead and real-time market offering from SPP. The Markets+ tariff was filed with FERC on March 29, 2024 and was approved on January 16, 2025. APS is a funding party to the implementation phase of Markets+ and expects to go live in the market in October 2027. In addition, APS is participating in the Western Resource Adequacy Program administered by Western Power Pool and plans to transition to full-binding participation in 2027 or 2028. These regional efforts are driven by the objectives of reducing customer cost and improving reliability. Until the transition to Markets+, APS will continue to participate in the WEIM as a tool for creating savings for APS's customers from the real-time only, voluntary market. APS expects that its participation in the WEIM and future participation in Markets+ will lower its fuel and purchased-power costs, improve situational awareness for systems operations in the Western Interconnection, and improve integration of APS's resources.

Resource Planning—Prioritizing Reliability and Affordability

APS remains focused on providing reliable energy at the lowest cost possible while striving to lower emissions over time and continues to look for opportunities to support reliability through dispatchable resources, such as gas and the potential extension of coal beyond 2031. APS's diverse portfolio of existing and planned resources includes biomass, biogas, coal, energy storage, geothermal, natural gas, nuclear, solar, and wind. Every three years, APS performs an IRP, a comprehensive study to identify what resources will be necessary to safely, reliably, and affordably meet the demand and energy needs of its customers over the next 15 years. In November 2023, APS released its latest IRP, which identified forecasted customer demand and energy needs growing at an unprecedented rate. In developing the IRP, APS considered how factors such as forecasted economic growth, impacts from weather, and new resource technology availability impact the amount and type of resources required to reliably and affordably meet customer needs. These factors, among others, were used to develop a plan that identified a balanced mix of diverse energy-generating resources to reliably serve customers' future energy needs. To help ensure competitive costs for resources procured by APS, APS regularly issues competitive bid solicitations through the ASRFP process, with the most recent ASRFP being issued in 2025. These ASRFPs are open to bids for all resource types, including customer-scale (behind the meter) and utility-scale (in front of the meter) resources.

APS selects projects out of ASRFPs based on cost, ability to meet system requirements, and commercial viability, taking into consideration timing and likelihood of successful contracting and development. Guided by IRP-established timelines and quantities, APS maintains a flexible approach that allows it to optimize system reliability and customer affordability through the ASRFP process. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection to the electric grid. Consistent with recent ASRFPs, APS remains focused on contracting for resources that can withstand supply chain pressures and volatility and seeks a balanced portfolio that is resilient to other external pressures, including those arising from the macroeconomic and geopolitical environment.

In terms of recent solicitations, APS issued an ASRFP on June 30, 2023, pursuant to which APS procured 3,606 MW of battery storage, 517 MW of natural gas, 2,649 MW of solar, and 500 MW of wind resources expected to be in service from 2026 to 2028. APS issued another ASRFP on November 20, 2024, pursuant to which it signed an amendment and extension to an existing gas tolling agreement, increasing it to 600 MW beginning in 2027 and extending the term to 2038 and is currently negotiating additional agreements. The scope of projects being negotiated out of the 2024 ASRFP reflects both the expanse of the 2023 ASRFP and the reality of adjusting to tariffs and changing federal policy.

In its most recent ASRFP, issued on November 19, 2025, APS is seeking at least 1,000 MW of resources that can reach commercial operation between 2029 and 2031, but APS will also consider projects that can achieve commercial operation earlier or later.

APS has an aspirational goal to be carbon-neutral by 2050. This means that for any GHG emissions still produced by our generation resources as of 2050, we will aim to offset these emissions elsewhere. This goal reflects APS's interest in new innovation and market transformations that address carbon emissions, while relying on the IRP and ASRFP processes to help determine the path forward.

Customer-Focused

Serving customers with excellence is foundational to APS's business and remains our core focus as we adapt to evolving customer needs and emerging technology. Recognizing that every employee impacts our customer experience, we continue to provide information, tools, and resources enabling our teams to design, develop, and implement enhancements to improve our customer experience.

APS's 24/7 call center answers more than 75% of customer calls within 30 seconds, and our mobile platforms enable our more than one million customers to quickly and easily find the information they need when they need it. We seek to provide relevant and valuable options for customers to manage their bill, including through rate plan options, programs that help them save energy and money, and alerts and notifications that help keep them aware of outages, payments, and usage. APS recently introduced a high-bill analyzer tool enabling phone advisors to provide customers with specific, customized guidance based on their actual usage and habits.

Additionally, APS offers a customer assistance program, including up to a 60% bill discount for vulnerable customers, flexible payment arrangements, and emergency utility bill assistance. To ensure customers in need are connected to these programs, we partner with nearly one hundred community action agencies across our service territory to train representatives who serve our shared customers.

Developing Technologies

New Nuclear Generation. Along with other Arizona electric utilities, APS is exploring additional nuclear generation to provide around-the-clock carbon-free energy to meet rising energy demands in Arizona. APS has been monitoring emerging nuclear technologies, ranging from newer proposed and installed versions of large-scale reactors to small modular nuclear reactors. Small modular nuclear reactors are typically designed to generate 300 MW or less of energy per unit compared to, for example, the 1,400 MW per unit generated at Palo Verde. The utilities have applied for a grant from DOE to begin preliminary exploration of a potential site for additional nuclear energy for Arizona. The grant could support a three-year site selection process and possible preparation of an early site permit application to NRC.

Long Duration Energy Storage. Continued technological innovation in long duration energy storage, which represents storage products which provide more than four hours of service, has led to decreasing cost of these solutions and an increase in their procurement, development, and deployment. These solutions include lithium and non-lithium battery chemistries, alternative natural gas-fired fuel cells and turbine units, and pumped hydropower. We will continue to evaluate these technologies and their ability to provide reliability, affordability, and balance to our portfolio.

Carbon Capture. CCS technologies can isolate carbon dioxide and either sequester it permanently in geologic formations or convert it for use in products. Currently, almost all existing fossil fuel generators do not control carbon emissions the way they control emissions of other air pollutants such as sulfur dioxide or oxides of nitrogen. CCS technologies are still in the demonstration phase and while they show promise, they are still being tested in real-world conditions. These technologies could potentially reduce carbon emissions from fossil fuel-fired generation.

Artificial Intelligence. To address the rapid advancement of AI technology risks and opportunities, APS has developed an AI strategy to responsibly utilize AI to advance our business strategy, enhance customer and employee experiences, and optimize operational reliability. At the core of our AI strategy is a robust governance model that develops guidance, policies, and relevant sub-strategies for the execution of AI projects at the Company. To ensure compliance with data security, reliability requirements, and our Code of Ethical Conduct, governance and oversight are provided by leadership and experts from our information technology, cybersecurity, human resources, ethics, supply chain, legal, and nuclear generation teams.

Regulatory Overview

2025 Rate Case

On June 13, 2025, APS filed an application with the ACC seeking a net base rate increase of $579.5 million, which represents a 13.99% net increase. The requested net increase addresses a total base revenue deficiency of $662.4 million, offset by proposed adjustor transfers of cost recovery to base rates.

The 2025 Rate Case application includes the following proposals:

- a test year comprised of the 12-month period ended on December 31, 2024, including certain pro forma adjustments;
- 12 months of post-test year plant placed into service from January 1, 2025 through December 31, 2025;
- an original cost rate base of $12.5 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	47.65 %	4.26 %
Common stock equity	52.35 %	10.70 %
Weighted-average cost of capital		7.63 %

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- a rate of $0.043881 per kWh for the portion of APS's base rates attributable to fuel and purchased power costs;
- adjustments to rate designs, including direct assignment of costs, to reduce cross-subsidization by certain customer classes;

- modification of cost allocation methodologies based on customer growth to ensure customers causing new production costs are covering those costs through rates, along with corresponding changes to adjustor mechanisms, such as for fuel and purchased power;
- implementation of a FRAM to assist with reducing regulatory lag and allow for rate gradualism;
- elimination of the LFCR following the first annual adjustment pursuant to the FRAM; and
- modification to the SRB due to the FRAM proposal.

APS requested that the increase become effective in the second half of 2026. The hearing for this rate case is currently scheduled to begin in May 2026. APS cannot predict the outcome of its request nor when the 2025 Rate Case will be decided by the ACC.

2022 Rate Case

On October 28, 2022, APS filed an application with the ACC (the “2022 Rate Case”) for an increase in retail base rates, and on January 25, 2024, an Administrative Law Judge issued a ROO, as corrected on February 6, 2024 (the “2022 Rate Case ROO”).

On February 22, 2024, the ACC approved the 2022 Rate Case ROO with certain amendments that resulted in, among other things, (i) an approximately $491.7 million increase in the annual base revenue requirement, (ii) a 9.55% return on equity, (iii) a 0.25% return on the increment of fair value rate base greater than original cost, (iv) an effective fair value rate of return of 4.39%, (v) a return set at the Company’s weighted average cost of capital on the net prepaid pension asset and net other post-employment benefit liability in rate base, (vi) an adjustment to generation maintenance and outage expense to reflect a more reasonable level of test year costs, (vii) approval of the SRB mechanism with modifications to customer notifications, procedural timelines and the inclusion of any qualifying technology and fuel source bid received through an ASRFP, and (viii) recovery of all DSM costs through the DSM Adjustment Charge (“DSMAC”) rather than through base rates.

The ACC issued the final order for the 2022 Rate Case on March 5, 2024, with the new rates becoming effective for all service rendered on or after March 8, 2024.

Six intervenors and the Attorney General of Arizona requested rehearing on various issues included in the ACC’s decision, such as the grid access charge (“GAC”) for solar customers, the SRB, and Coal Community Transition funding. On April 15, 2024, the ACC granted, in part, the rehearing applications of the Attorney General, Arizona Solar Energy Industries Association (“AriSEIA”), Solar Energy Industries Association (“SEIA”), and Vote Solar specifically to review whether the GAC rate is just and reasonable, including whether it should be higher or lower, whether the GAC rate constitutes a discriminatory fee to solar customers, and whether omission of a GAC charge is discriminatory to non-solar customers. All other applications for rehearing were denied. A limited rehearing was held October 28 through November 1, 2024. Following the limited rehearing, an Administrative Law Judge issued a ROO (the “Limited Rehearing ROO”) on December 3, 2024. The Limited Rehearing ROO recommended affirming the GAC as just and reasonable and that the GAC is not discriminatory to solar customers and the absence of a GAC is not discriminatory to non-solar customers. On December 17, 2024, the ACC approved the Limited Rehearing ROO with an amendment that requires APS in its next rate case to propose a revenue allocation based on a site-load cost of service study in order to bring further parity in revenue collection between solar and non-solar customers. SEIA, AriSEIA, Vote Solar, the Arizona Attorney General, and two individual customers have filed requests for rehearing of the ACC’s December 17, 2024 decision on the rehearing. The ACC has taken no action on these requests. In addition, each of these parties have subsequently filed an appeal to the Arizona Court of Appeals seeking review of the ACC's decisions regarding the GAC and on rehearing. APS cannot predict the outcome of these proceedings.

Regulatory Lag Docket

On January 5, 2023, the ACC opened a new docket to explore the possibility of modifications to the ACC's historical test year rules. The ACC requested comments and held two workshops exploring ways to reduce regulatory lag, including alternative ratemaking structures such as future test years, hybrid test years, and formula rates. On December 3, 2024, the ACC approved a policy statement regarding formula rate plans. The policy statement provides regulated utilities with the opportunity to propose formula rate plans in future rate cases. On March 28, 2025, the Residential Utility Consumer Office ("RUCO"), the Arizona Large Customer Group ("ALCG"), and an individual customer filed a lawsuit challenging the ACC's authority to issue the formula rate policy statement outside of Arizona's formula rulemaking process. On June 13, 2025, the lawsuit challenging the ACC's formula rate policy was dismissed by the Superior Court of Maricopa County. Following the dismissal, the plaintiffs filed an appeal with the Arizona Court of Appeals as well as a Petition for Special Action with the Arizona Supreme Court. The Supreme Court declined to exercise jurisdiction on the Petition for Special Action. The plaintiffs also filed a Petition for Special Action with the Arizona Court of Appeals, which has accepted jurisdiction to determine whether the case should be remanded back to the Superior Court for expedited consideration of the merits. On November 21, 2025, the Arizona Court of Appeals ruled that the issue should be remanded back to the Superior Court to determine whether the ACC's formula rate policy must go through a formal rulemaking process. In response, APS, the ACC, and several other Arizona utility companies filed petitions for review of the Court of Appeals decision with the Arizona Supreme Court, which is pending at this time. APS cannot predict the outcome of this matter.

See Note 8 for more information regarding these and additional regulatory matters.

Captive Insurance Cell

Pinnacle West is the primary beneficiary of a protected cell captive insurance cell. The Captive provides insurance coverage to Pinnacle West and our subsidiaries that supplements commercial and mutual insurance coverage. The Captive insures Pinnacle West and its subsidiaries for terrorism coverage, excess liability including certain wildfire coverage, excess property insurance, and excess employment practice liability. The Captive policies exclude nuclear liability at Palo Verde. See Note 12. The Captive may hold investment assets in cash, cash equivalents, and equity and fixed income instruments.

Tax Incentives

The Inflation Reduction Act of 2022 ("IRA") significantly expanded the availability of tax credits for investments in clean energy generation technologies and energy storage. Key provisions included (i) an extension of tax credits for solar and wind generation, including a new option for solar investments to claim a PTC in lieu of the ITC beginning in 2022; (ii) expansion of the ITC to cover stand-alone energy storage technology beginning in 2023; (iii) introduction of technology neutral clean energy ITCs and PTCs beginning in 2025; and (iv) introduction of a new PTC for nuclear energy produced by existing nuclear energy plants, available from 2024 through 2032.

On July 4, 2025, the One Big Beautiful Bill Act ("OBBBA"), was signed into law. The OBBBA curtailed several clean energy tax credits initially passed in the IRA, including a new phase out deadline for wind and solar ITCs and PTCs that requires projects to either begin construction within one year of enactment or be placed in service by December 31, 2027. Additionally, the OBBBA contained provisions restricting clean energy projects, including energy storage, which begin construction after December 31, 2025, and receive "material assistance from a prohibited foreign entity," from being eligible for clean energy ITCs or PTCs.

The Company believes that its projects which are currently under construction will continue to qualify for IRA tax credits. See Note 5 for information on Palo Verde's nuclear PTC. The Company is continuing to analyze the OBBBA and is awaiting regulations and other guidance as to the application of these new rules to projects not currently under construction.

Financial Strength and Flexibility

We believe that Pinnacle West and APS currently have ample borrowing capacity under their respective credit facilities and may readily access these facilities ensuring adequate liquidity for each company. Capital expenditures are anticipated to be funded with internally generated cash and external financings, which may include issuances of long-term debt and Pinnacle West common stock.

Other Subsidiaries

PNW Power

PNW Power holds certain investments and assets that were previously held by BCE, a former subsidiary of Pinnacle West that was sold in 2024. PNW Power's investments include TransCanyon, a 50/50 joint venture that was formed in 2014 with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. TransCanyon is pursuing independent electric transmission opportunities within the 11 U.S. states that comprise the Western Interconnection, excluding opportunities related to transmission service that would otherwise be provided under the tariffs of the retail service territories of the TransCanyon partners' utility affiliates. These opportunities include the proposed 500-kV Cross-Tie transmission project (the "Cross-Tie Project"), which includes a 214-mile transmission line connecting Utah and Nevada that is intended to help improve grid reliability and relieve congestion on other transmission lines. On December 18, 2025, the Department of Interior Bureau of Land Management issued a Record of Decision permitting the development of Cross-Tie Project, which became non-appealable in late January 2026.

PNW Power's investments also include minority ownership positions in two wind farms operated by Tenaska Energy, Inc. and Tenaska Energy Holdings, LLC, the 242 MW Clear Creek and the 250 MW Nobles 2 wind farms. Clear Creek achieved commercial operation in May 2020; however, in the fourth quarter of 2022, PNW Power's equity method investment was fully impaired. Nobles 2 achieved commercial operation in December 2020. Both wind farms deliver power under long-term PPAs. PNW Power indirectly owns 9.9% of Clear Creek and 5.1% of Nobles 2.

El Dorado

El Dorado owns debt investments and minority interests in several energy-related investments and Arizona community-based ventures. In particular, El Dorado has committed to and/or holds the following:

- $25 million investment in the Energy Impact Partners fund, of which approximately $20 million has been funded as of December 31, 2025. Energy Impact Partners is an organization that focuses on fostering innovation and supporting the transformation of the utility industry.

- $25 million investment in AZ-VC, of which approximately $16 million has been funded as of December 31, 2025. AZ-VC is a fund focused on analyzing, investing, managing, and otherwise dealing with investments in privately-held early stage and emerging growth technology companies and businesses primarily based in Arizona, or based in other jurisdictions and having existing or potential strategic or economic ties to companies or other interests in Arizona.

- $7.5 million investment in Westly Seed Fund, of which approximately $2 million has been funded as of December 31, 2025. Westly Seed Fund is focused on supporting entrepreneurs involved in the energy, mobility, building, and industrial sectors.

- Equity investment in SAI, a private corporation that manufactures electrical switchgear equipment used by data centers. El Dorado accounts for this investment under the equity method and has an investment carrying value of approximately $21 million as of December 31, 2025.

The remainder of these investment commitments will be contributed by El Dorado as each investment fund selects and makes investments.

Key Financial Drivers

In addition to the continuing impact of the matters described above, many factors influence our financial results and our future financial outlook, including those listed below. We closely monitor these factors to plan for the Company's current needs, and to adjust our expectations, financial budgets and forecasts appropriately.

Electric Operating Revenues. For 2025, retail electric revenues were 95% of our total operating revenue. For 2023 through 2025, retail electric revenues averaged approximately 94% of our total operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, distributed energy additions, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery mechanisms. Our revenues are affected by the availability of excess generation or other energy resources and wholesale market conditions, including competition, demand, and prices.

Actual and Projected Customer and Sales Growth. Retail customers in APS's service territory increased 2.4% for the period ended December 31, 2025 compared with the prior-year period. For the three years through 2025, APS's customer growth averaged 2.2% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2026 and the average annual growth to be in the range of 1.5% to 2.5% through 2030 based on anticipated steady population growth in Arizona during that period.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 5.0% for the period ended December 31, 2025 compared with the prior-year period. While steady customer growth was somewhat offset by lower usage among residential customers, energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives, the main drivers of increased revenues for this period were continued strong sales to commercial and industrial customers and the continued ramp-up of new data center and large manufacturing customers. As large load customers, such as data centers and large manufacturers, have continued to grow as a proportion of our business, we have updated our procedures with respect to estimates of unbilled revenues for our customer classes. As a result, we made an adjustment in the first quarter of 2025 to recalibrate accrued unbilled revenues, offsetting year-to-date sales growth by 0.4%.

For the three years through 2025, annual retail electricity sales growth averaged 3.9%, adjusted to exclude the effects of weather variations. Due to the expected growth of several data centers and large manufacturing facilities, we currently project that annual retail electricity sales in kWh will increase in the range of 4.0% to 6.0% for 2026 and that average annual growth will be in the range of 5.0% to 7.0% through 2030, including the effects of customer conservation, energy efficiency, and distributed renewable generation initiatives, but excluding the effects of weather variations. These projected sales growth ranges include the impacts of several data centers and large manufacturing facilities, which are expected to contribute to 2026 growth in the range of 3.0% to 5.0% and to average annual growth in the range of 4.0% to 6.0% through 2030.

Longer term, APS has been preparing for and can serve significant load growth from residential and business customers. On top of these existing growth trends, APS is also receiving incremental requests for service from large load customers with very high energy demands that persist virtually around-the-clock, such as data centers for AI and large manufacturers. These incremental requests for service by large load customers far exceed available generation and transmission resource capacity in the Southwest region for the foreseeable future. Because of the high growth in demand for such projects, APS has developed a queue that identifies and prioritizes projects while maintaining system reliability and affordability for existing APS customers. APS is also exploring available options for securing additional electric generation and transmission to meet these projections of future customer needs, including a new subscription model for large load customers. The subscription model is part of the company's "growth pays for growth" strategy where large load customers would enter into a long-term special contract to pay for the costs associated with the incremental infrastructure needed to provide service without compromising reliability and affordability for existing customers.

Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as macroeconomic conditions, current and future economic, regulatory, business, and other conditions, such as the Arizona housing market, customer growth, usage patterns and energy conservation, slower ramp-up of and/or fewer large data centers and manufacturing facilities, slower than expected commercial and industrial expansions, impacts of energy efficiency programs and growth in DG, responses to retail price changes, changes in regulatory standards, and impacts of new and existing laws and regulations, including environmental laws and regulations. Based on past experience, a 1% variation in our annual residential and small commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $25 million, and a 1% variation in our annual large commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $7 million.

Weather. In forecasting the retail sales growth numbers provided above, we assume normal weather patterns based on historical data. Our experience indicates that typical variations from normal weather can result in increases and decreases in annual net income of up to $20 million. However, since 2020, extreme weather events, such as record-setting summer heat and decreased annual precipitation in our service territory, have resulted in increases in annual net income that are more than historically typical, on average.

Fuel and Purchased Power Expenses. Fuel and purchased power expenses included on our Consolidated Statements of Income are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, transmission availability or constraints, prevailing market prices, new generating plants being placed in service in our market areas, changes in our generation resource allocation, our hedging program for managing such costs and PSA deferrals and the related amortization.

Operations and Maintenance Expenses. Operations and maintenance expenses are impacted by customer and sales growth, power plant operations, maintenance of utility plant (including generation, transmission, and distribution facilities), inflation, unplanned outages, planned outages (typically scheduled in the spring and fall), renewable energy and DSM related expenses (which are mostly offset by the same amount of operating revenues) and other factors.

Depreciation and Amortization Expenses. Depreciation and amortization expenses are impacted by net additions to utility plant and other property (such as new generation, transmission, and distribution facilities), and increases in intangible assets and changes in depreciation and amortization rates. See "Liquidity and Capital Resources" below for information regarding the planned additions to our facilities.

Pension and Other Postretirement Non-Service Credits, Net. Pension and other postretirement non-service credits can be impacted by changes in our actuarial assumptions. The most relevant actuarial assumptions are the discount rate used to measure our net periodic costs/credit, the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term, the mortality assumptions and the assumed healthcare cost trend rates. We review these assumptions on an annual basis and adjust them, as necessary. See Note 9.

Property Taxes. Taxes other than income taxes consist primarily of property taxes, which are affected by changes in plant balances related to new investments and improvements to existing facilities, the value of property in service and under construction, assessment ratios, and tax rates. The average property tax rate in Arizona for APS, which owns essentially all of our property, was 9.6% of the assessed value for 2025, 9.7% for 2024, and 10.0% for 2023. Property tax increased in 2025 due to higher plant balances related to expansion and improvements on our existing generation, transmission, and distribution facilities, partially offset by legislative changes reducing both tax assessment ratios and rates in Arizona.

Income Taxes. Income taxes are affected by the amount of pretax book income, income tax rates, certain deductions, certain credits and non-taxable items, such as AFUDC. In addition, income taxes may also be affected by the settlement of issues with taxing authorities.

Interest Expense. Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. See Notes 6 and 7 for further details. The primary factors affecting borrowing levels are expected to be our capital expenditures, long-term debt maturities, equity issuances and internally generated cash flow. AFUDC offsets a portion of interest expense while capital projects are under construction. We stop accruing AFUDC on a project when it is placed into service.

RESULTS OF OPERATIONS

Pinnacle West's reportable business segment is our regulated electricity segment, which consists of retail and wholesale sales supplied under traditional cost-based regulation and related activities and includes electricity generation, transmission, and distribution. Our reportable segment activities are conducted through our wholly-owned subsidiary, APS. All other operating segment activities are insignificant to Pinnacle West.

Operating Results – 2025 compared with 2024

Our consolidated net income attributable to common shareholders for the year ended December 31, 2025 was $617 million, compared with consolidated net income attributable to common shareholders of $609 million for the prior-year period. The results reflect an increase of approximately $8 million, primarily as a result of increased customer usage, customer growth and related pricing, higher transmission revenues, impacts of new customer rates, higher LFCR revenue, and higher AFUDC. These positive factors were partially offset by the effects of weather, due primarily to extreme heat during the summer of 2024, the hottest on record in APS's service territory. Additional offsets include higher interest charges, lower pension and other postretirement non-service credits, higher depreciation and amortization expenses mostly due to increased plant additions and intangible assets, partially offset by operations ceasing at the Cholla plant and higher operations and maintenance expenses.

The following table presents net income attributable to common shareholders compared with the prior year for Pinnacle West consolidated and for APS consolidated (dollars in millions):

	Pinnacle West Consolidated			APS Consolidated		
	Year Ended December 31,			Year Ended December 31,		
	2025	2024	Net Change	2025	2024	Net Change
Operating revenues	$ 5,340	$ 5,125	$ 215	$ 5,340	$ 5,125	$ 215
Fuel and purchased power	(1,933)	(1,823)	(110)	(1,933)	(1,823)	(110)
Operating revenues less fuel and purchased power (a)	3,407	3,302	105	3,407	3,302	105
Operations and maintenance	(1,185)	(1,165)	(20)	(1,177)	(1,159)	(18)
Depreciation and amortization	(915)	(895)	(20)	(915)	(895)	(20)
Taxes other than income taxes	(235)	(227)	(8)	(235)	(227)	(8)
Allowance for equity funds used during construction	61	39	22	61	39	22
Pension and other postretirement non-service credits, net	12	49	(37)	13	49	(36)
Other income and (expense), net	16	11	5	(14)	(11)	(3)
Interest charges, net of allowance for borrowed funds used during construction	(422)	(377)	(45)	(332)	(312)	(20)
Income taxes	(107)	(111)	4	(126)	(127)	1
Less: Net income related to noncontrolling interests	(15)	(17)	2	(15)	(17)	2
Net Income Attributable to Common Shareholders	$ 617	$ 609	$ 8	$ 667	$ 642	$ 25

(a) Operating revenues less fuel and purchased power is a non-GAAP financial measure. As reconciled in the table above, this amount is derived by the difference between the GAAP financial statement line item Operating revenues less the GAAP financial statement line item Fuel and purchased power as presented on the Consolidated Statements of Income. Operating revenues, less fuel and purchased power is used by Pinnacle West to assess whether customer revenues adequately cover fuel and purchased power costs. This metric is not defined by

GAAP and may differ from similar measures used by other companies. This measure is not a substitute for operating income under GAAP.

Operating revenues less fuel and purchased power. Operating revenues less fuel and purchased power expenses were $105 million higher for the year ended December 31, 2025 compared with the prior-year period. The following table summarizes the major components of this change (dollars in millions):

	Increase (Decrease)		
	Operating revenues	Fuel and purchased power	Net change
Higher retail revenues due to changes in usage patterns, customer growth and related pricing, partially offset by the impacts of energy efficiency	$ 155	$ 60	$ 95
Higher transmission revenues (Note 8)	51	—	51
Impact of new rates from the 2022 Rate Case, effective March 8, 2024 (Note 8)	46	—	46
LFCR revenue (Note 8)	10	—	10
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	97	89	8
Higher renewable energy regulatory surcharges, partially offset by operations and maintenance costs	9	5	4
Effects of weather	(157)	(43)	(114)
Miscellaneous items, net	4	(1)	5
Total	$ 215	$ 110	$ 105

Operations and maintenance. Operations and maintenance expenses increased $20 million for the year ended December 31, 2025 compared with the prior-year period, primarily due to:

- an increase of $19 million related to information technology costs;
- an increase of $16 million related to corporate resource costs;
- an increase of $2 million related to nuclear generation costs;
- an increase of $2 million related to costs for renewable energy programs and similar regulatory programs, which are partially offset in operating revenues and purchased power;
- an increase of $1 million related to non-nuclear generation costs, primarily due to increased operating costs;
- a decrease of $11 million related to transmission, distribution, and customer service costs;
- a decrease of $13 million related to employee benefit costs; and
- an increase of $4 million for other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $20 million higher for the year ended December 31, 2025 compared to the prior-year period, primarily due to increased plant in service and intangible assets, partially offset by lower depreciation expense due to operations ceasing at the Cholla plant.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $37 million lower for the year ended December 31, 2025 compared to the prior-year period primarily due to prior-service credits becoming fully amortized as of January 31, 2025.

Other income and expense, net. Other income and expense, net was $5 million higher for the year ended December 31, 2025 compared to the prior-year period, primarily due to investment gains in El Dorado, partially offset by the gain on the sale of BCE recognized during the first quarter of 2024, lower PSA interest income and higher corporate giving expense. The difference between APS's and Pinnacle West's other income and expense, net is primarily related to Pinnacle West's gain in investment in El Dorado and the gain on the sale of BCE.

Interest charges, net of allowance for borrowed funds and equity funds used during construction. Interest charges, net of allowance for funds used during construction, were $23 million higher for the year ended December 31, 2025 compared to the prior-year period, primarily due to higher debt balances and lower allowance for borrowed funds, partially offset by higher allowance for equity funds.

Income taxes. Income taxes were $4 million lower for the year ended December 31, 2025 compared with the prior-year period, primarily due to higher tax benefits related to employee benefits and AFUDC Equity, offset by lower tax credits and higher pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Pinnacle West's primary cash needs are for dividends to our shareholders and principal and interest payments on our indebtedness. The level of our common stock dividends and future dividend growth will be dependent on declaration by our Board of Directors and based on a number of factors, including our financial condition, payout ratio, free cash flow and other factors.

Our primary sources of cash are dividends from APS and external debt and equity issuances. An ACC order does not allow APS to pay common dividends if the payment would reduce its common equity ratio below 40%. Per the related ACC order, the common equity ratio is defined as total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. As of December 31, 2025, APS's common equity ratio, as defined, was 52%. APS's total shareholder equity was approximately $8.9 billion, and total capitalization, as calculated pursuant to the ACC order, was approximately $17.1 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $6.8 billion, assuming APS's total capitalization remains the same. This restriction does not materially affect Pinnacle West's ability to meet its ongoing cash needs or ability to pay dividends to shareholders.

Dividends to Pinnacle West from APS are also dependent on a number of factors including, among others, APS's financial condition and free cash flow, the sources of which vary from quarter-to-quarter due in part to the seasonal nature of electricity demand in Arizona. APS's sources of cash include cash from operations and external sources of liquidity, including long- and short-term external debt financing such as commercial paper, term loans and its revolving credit facility. Cash from operations is dependent upon, among other things, the rates APS may charge and the timeliness of recovering costs incurred through its rates and adjustor recovery mechanisms. Regulatory lag may delay recovery and affect operating cash flows. APS's capital requirements consist primarily of capital expenditures and maturities of long-term debt. APS funds its capital requirements with cash from operations and, to the extent necessary, external debt financings and equity infusions from Pinnacle West. On December 17, 2024, the ACC issued a financing order approving a limit on yearly equity infusions equal to 2.5% of APS's total assets each calendar year on a three-year rolling average basis, subject to APS's equity ratio remaining below the most recently approved rate case capital structure plus 50 basis points.

On May 15, 2025, Pinnacle West contributed $300 million into APS in the form of an equity infusion. APS used this contribution to repay the $300 million of its 3.15% senior notes that matured on the same date. On December 18, 2025, Pinnacle West contributed $75 million into APS in the form of an equity infusion. APS used this contribution to repay a portion of its commercial paper borrowings.

Pinnacle West and APS maintain committed revolving credit facilities that enhance liquidity and provide credit support for accessing commercial paper markets. These credit facilities mature in 2031.

Pinnacle West has an ATM Program under which Pinnacle West may offer and sell Pinnacle West common stock and enter into forward sale agreements from time to time, subject to market conditions and other factors. Approximately $700 million of common stock is available to be issued under the ATM Program, which takes into account the forward sale agreements in effect as of December 31, 2025. Pinnacle West also has forward sale agreements from an equity offering in February 2024 in effect as of December 31, 2025. See "Financing Cash Flows and Liquidity—Equity Offerings" below and Note 16 for more information.

Summary of Cash Flows

The following tables present net cash provided by (used for) operating, investing and financing activities for the years ended December 31, 2025, and 2024 (dollars in millions):

Pinnacle West Consolidated

	Year Ended December 31,		
	2025	2024	Net Change
Net cash flow provided by operating activities	$ 1,805	$ 1,610	$ 195
Net cash flow used for investing activities	(2,378)	(1,934)	(444)
Net cash flow provided by financing activities	576	323	253
Net increase (decrease) in cash and cash equivalents	$ 3	$ (1)	$ 4

APS Consolidated

	Year Ended December 31,		
	2025	2024	Net Change
Net cash flow provided by operating activities	$ 1,827	$ 1,610	$ 217
Net cash flow used for investing activities	(2,370)	(1,986)	(384)
Net cash flow provided by financing activities	543	375	168
Net increase (decrease) in cash and cash equivalents	$ —	$ (1)	$ 1

Operating Cash Flows

2025 Compared with 2024. Pinnacle West's consolidated net cash provided by operating activities was $1,805 million in 2025 compared to $1,610 million in 2024, an increase of $195 million in net cash provided, primarily due to $238 million higher cash receipts from electric revenues, $111 million in lower income taxes paid and $60 million lower payments for operations and maintenance costs; partially offset by $162 million higher payments for fuel and purchased power costs, $29 million in higher interest paid on debt and $23 million of changes in working capital. The difference between APS's and Pinnacle West's net cash provided by operating activities primarily relates to APS's lower payments for other taxes and other changes in working capital.

Retirement plans and other postretirement benefits. Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. Pinnacle West also sponsors other postretirement benefit plans for the employees of Pinnacle West and its subsidiaries. The requirements of the Employee Retirement Income Security Act of 1974 ("ERISA") require us to contribute a minimum amount to the qualified plan. We contribute at least the minimum amount required under ERISA regulations, but no more than the maximum tax-deductible amount. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. The expected minimum required cash contributions for the pension plan are zero for the next three years and we do not expect to make any voluntary cash contributions in 2026, 2027 or 2028; however, we continue to evaluate and assess our ongoing contribution strategy. Regarding contributions to our other postretirement benefit plan, we did not make a contribution in 2025 and do not expect to make any contributions in 2026, 2027 or 2028. We continually monitor financial market volatility and its impact on our retirement plans and other postretirement benefits, but we believe our liability driven investment strategy helps to minimize the impact of market volatility on our plan's funded status.

Investing Cash Flows

2025 Compared with 2024. Pinnacle West's consolidated net cash used for investing activities was $2,378 million in 2025 compared to $1,934 million in 2024, an increase of $444 million primarily related to $380 million of increased capital expenditures, net of contributions in aid of construction, and $84 million of proceeds from the BCE Sale received in 2024; partially offset by $20 million less investing activity in the current year. See "Capital Expenditures" below for additional details. The difference between APS's and Pinnacle West's net cash used for investing activities primarily relates to the proceeds received from the BCE Sale and investments made into the Captive Insurance Cell VIE in the prior year.

Capital Expenditures. The following table summarizes the estimated capital expenditures for the next three years (dollars in millions):

Capital Expenditures

	Estimated for the Year Ending December 31,		
	2026	**2027**	**2028**
APS			
Generation:			
Gas and Other Generation	$ 635	$ 550	$ 490
Nuclear Generation	170	185	215
Renewables and Energy Storage	20	5	5
Distribution	765	795	750
Transmission	550	695	860
Other	460	420	380
Total APS	$ 2,600	$ 2,650	$ 2,700

The table above does not include capital expenditures related to PNW Power projects.

Generation capital expenditures are comprised of various additions and improvements to APS's resources, including nuclear plants, renewables and energy storage, additions and improvements to existing fossil fuel plants, as well as planned investments in new natural gas facilities. We are monitoring the status of environmental matters, which, depending on their final outcome, could require modification to our planned environmental expenditures.

Distribution and transmission capital expenditures are comprised of infrastructure additions and upgrades, capital replacements, and new customer construction. Examples of the types of projects included in the forecast include power lines, substations, and line extensions to new residential and commercial developments.

Capital expenditures are expected to be funded with internally generated cash and external financings, which may include issuances of long-term debt and Pinnacle West common stock.

Financing Cash Flows and Liquidity

2025 Compared with 2024. Pinnacle West's consolidated net cash provided by financing activities was $576 million in 2025 compared to $323 million in 2024, an increase of $253 million in net cash provided primarily due to an increase of $430 million higher issuances of long-term debt, a $230 million increase in short-term borrowings and $75 million lower repayment of long-term debt; partially offset by $257 million less for equity issuances, the $199 million payment for the Palo Verde sale leaseback noncontrolling interest acquisition and higher dividends paid of $28 million.

APS's consolidated net cash provided by financing activities was $543 million in 2025 compared to $375 million in 2024, an increase of $168 million in net cash provided primarily due to an increase of $502 million higher issuances of long-term debt, a $360 million increase in short-term borrowings; partially offset by $420 million in lower equity infusions from Pinnacle West, the $199 million payment for the Palo Verde sale leaseback noncontrolling interest acquisition, $50 million higher long-term debt repayments and $28 million in higher dividends paid to Pinnacle West.

Significant Financing Activities. On December 10, 2025, the Pinnacle West Board of Directors declared a dividend of $0.91 per share of common stock, payable on March 2, 2026, to shareholders of record on February 2, 2026. During 2025, Pinnacle West increased its indicated annual dividend from $3.58 per share to $3.64 per share. For the year ended December 31, 2025, Pinnacle West's total dividends paid per share of common stock were $3.60 per share, which resulted in dividend payments of $423 million.

Available Credit Facilities. Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper. See Note 6 for more information on available credit facilities.

Equity Offerings. Pinnacle West entered into certain equity forward sale agreements in February 2024 and has an ATM Program under which Pinnacle West may offer and sell Pinnacle West common stock and enter into equity forward sale agreements from time to time, subject to market conditions and other factors. See Note 16. The following table summarizes the activity relating to these forward sale agreements and the ATM Program as of December 31, 2025 (dollars in thousands, except price per share):

Forward Sale Agreements	Number of Shares		Forward Sales Price Per Share			Aggregate Value	
February 2024 Forward Sale Agreements							
Initial Price	11,240,601		$ 64.51	(a)		$ 725,131	
Settlements							
December 23, 2024	5,377,115	(b)	$ 64.17			$ 345,049	(c)
September 4, 2025	243,186	(b)	$ 63.12			$ 15,350	(c)
December 18, 2025	1,193,950	(b)	$ 62.82			$ 75,004	(c)
ATM Program							
Initial Price	2,199,415		$ 90.1038	(a)	(d)	$ 198,176	

(a) Subject to certain adjustments.
(b) Physical delivery.
(c) Proceeds recorded in common equity on the Consolidated Balance Sheets.
(d) Weighted-average price for the total ATM Program.

Other Financing Matters. See Note 13 for information related to the change in our margin and collateral accounts.

Debt Provisions

Pinnacle West's and APS's debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with these covenants. For both Pinnacle West and APS, these covenants require that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. As of December 31, 2025, the ratio was approximately 60% for Pinnacle West and 50% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could "cross-default" other debt. See further discussion of "cross-default" provisions below.

Neither Pinnacle West's nor APS's financing agreements contain "rating triggers" that would result in an acceleration of payment in the event of a rating downgrade. However, our bank credit agreements contain a pricing grid in which the interest rates we pay for borrowings thereunder are determined by our current credit ratings.

All of Pinnacle West's and APS's credit agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment if Pinnacle West or APS were to default under certain other material agreements. Pinnacle West and APS do not have a material adverse change covenant for credit facility borrowings.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of February 20, 2026, are shown below. We are disclosing these credit ratings to enhance understanding of our cost of short-term and long-term capital and our ability to access the markets for liquidity and long-term debt. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS's securities and/or result in an increase in the cost of, or limit access to, capital. Such revisions may also result in substantial additional cash or other collateral requirements related to certain derivative instruments, insurance policies, natural gas transportation, fuel supply, and other energy-related contracts. At this time, we believe we have sufficient available liquidity resources to respond to a potential downward revision to our credit ratings.

	Moody's	Standard & Poor's	Fitch
Pinnacle West			
Corporate credit rating	Baa2	BBB+	BBB
Senior unsecured	Baa2	BBB	BBB
Commercial paper	P-2	A-2	F3
Outlook	Stable	Stable	Stable
APS			
Corporate credit rating	Baa1	BBB+	BBB+
Senior unsecured	Baa1	BBB+	A-
Commercial paper	P-2	A-2	F2
Outlook	Stable	Stable	Stable

Contractual Obligations

Pinnacle West has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. Material contractual obligations and other commitments are as follows:

- Pinnacle West and APS have material long-term debt obligations that mature at various dates through 2055 and bear interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using average rates at December 31, 2025. See Note 7.

- Pinnacle West and APS maintain committed revolving credit facilities. See Note 6 for short-term debt details.

- Fuel and purchased power commitments include purchases of coal, electricity, natural gas, renewable energy, nuclear fuel, and natural gas transportation. See Notes 8 and 14. Purchase obligations may include commitments for capital expenditures and other obligations. See Note 14. Commitments related to purchased power lease contracts are also considered fuel and purchased power commitments. See Note 20.

- APS holds certain contracts to purchase renewable energy credits in compliance with the RES. See Notes 8 and 14.

- APS is required to make payments to the noncontrolling interests related to the Palo Verde sale leaseback through 2033. See Note 12.

- APS must reimburse certain coal providers for final and contemporaneous coal mine reclamation. See Note 14.

- Pinnacle West's equity forward sale agreements, which may be settled by Pinnacle West with common stock or cash. Pinnacle West has classified these agreements as equity transactions in accordance with GAAP. See Note 16.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In preparing the financial statements in accordance with GAAP, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. We consider the following accounting policies to be our most critical because of the uncertainties, judgments and complexities of the underlying accounting standards and operations involved.

Regulatory Accounting

Regulatory accounting allows for the actions of regulators, such as the ACC and FERC, to be reflected in our financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred and are refundable to customers. Management judgments include continually assessing the likelihood of future recovery of regulatory assets and/or a disallowance of part of the cost of recently completed plant, by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in Arizona and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings, except for pension benefits, which would be charged to other comprehensive income and result in lower future earnings. Management judgments also include assessing the impact of potential ACC- or FERC-ordered refunds to customers on regulatory liabilities. We had $1,749 million of regulatory assets and $1,947 million of regulatory liabilities on the Consolidated Balance Sheets at December 31, 2025. See Notes 1 and 8 for more information.

Pensions and Other Postretirement Benefit Accounting

Changes in our actuarial assumptions used in calculating our pension and other postretirement benefit assets, liabilities and expense can have a significant impact on our earnings and financial position. We review these assumptions on an annual basis and adjust them as necessary. The most relevant actuarial assumptions are the discount rate, the expected long-term rate of return on plan assets ("EROA"), and the assumed healthcare cost trend rates. Differences between these actuarial assumptions and actual plan results may create volatility in pension and other postretirement benefit expense. To reduce this volatility, these differences are accumulated and amortized (subject to a corridor of 10% of the greater of plan assets or obligations) as part of the expense over a period of approximately 11 years. Following are the most relevant actuarial assumptions:

Discount Rate. The discount rate is used to measure the plan liability and net periodic cost. For this assumption, we utilize a yield curve produced by our actuary as of December 31st and employ their projections of the future benefit payments to estimate the projected benefit obligation for each plan. This process also yields a single equivalent discount rate that produces the same present value for the projection of estimated benefit payments that is generated by discounting each year's benefit payments by a spot rate to that year. The spot rates are derived from a yield curve composed of domestic AA rated corporate bonds.

EROA. The EROA is used to estimate earnings on invested funds over the long-term. For this assumption, we consider historical experience and future expectations of asset classes utilized in the portfolio.

Healthcare Cost Trend Rates. We consider past performance and forecasts of health care costs, and our actuary provides the Company with a medical trend recommendation based on national medical trend, historical claims performance, benchmarking, and plan design changes.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2025, reported pension assets and liabilities on the Consolidated Balance Sheets and our 2025 reported pension expense, after consideration of amounts capitalized or billed to electric plant participants, on the Consolidated Statements of Income (dollars in millions):

	Increase (Decrease)	
Actuarial Assumption (a)	**Impact on Pension Plans (Assets) Liabilities**	**Impact on Pension Expense (Benefit)**
Discount rate (b):		
Increase 1%	$ (236)	$ (8)
Decrease 1%	279	8
EROA:		
Increase 1%	—	(19)
Decrease 1%	—	19

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant while the rates are changed by one percentage point.
(b) In general, changes in the discount rate will not typically have symmetrical effects for increases and decreases of the rate. Further, a 1% change in a low discount rate environment will have a larger impact than a 1% change in a high discount rate environment. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated. Additionally, the Pension Plan utilizes a liability-driven strategy for its pension asset portfolio, and the obligation and expense sensitivities shown above do not reflect the offsetting impact that a change in interest rates may have on pension asset values.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2025 other postretirement benefit obligation on the Pinnacle West's Consolidated Balance Sheets and our 2025 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

	Increase (Decrease)	
Actuarial Assumption (a)	**Impact on Other Postretirement Benefit Plans (Assets) Liabilities**	**Impact on Other Postretirement Benefit Expense (Benefit)**
Discount rate (b):		
Increase 1%	$ (33)	$ (1)
Decrease 1%	40	2
Healthcare cost trend rate (c):		
Increase 1%	13	2
Decrease 1%	(11)	(1)
EROA – pretax:		
Increase 1%	—	(5)
Decrease 1%	—	5

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant while the rates are changed by one percentage point.
(b) In general, changes in the discount rate will not typically have symmetrical effects for increases and decreases of the rate. Further, a 1% change in a low discount rate environment will have a larger impact than a 1% change in a high discount rate environment. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated.
(c) This assumes a 1% change in the initial and ultimate healthcare cost trend rate.

See Note 9 for further details about our pension and other postretirement benefit plans.

Fair Value Measurements

We account for derivative instruments, investments held in our nuclear decommissioning trusts fund, investments held in our other special use funds, certain cash equivalents, and plan assets held in our retirement and other benefit plans at fair value on a recurring basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. We use inputs, or assumptions that market participants would use, to determine fair market value. We utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The significance of a particular input determines how the instrument is classified in a fair value hierarchy. The determination of fair value sometimes requires subjective and complex judgment. Our assessment of the inputs and the significance of a particular input to fair value measurement may affect the valuation of the instruments and their placement within a fair value hierarchy. Actual results could differ from our estimates of fair value. See Note 1 for a discussion of accounting policies and Note 17 for fair value measurement disclosures.

Asset Retirement Obligations

We recognize an ARO for the future decommissioning or retirement of our tangible long-lived assets for which a legal obligation exists. The ARO liability represents an estimate of the fair value of the current obligation related to decommissioning and the retirement of those assets. ARO measurements inherently involve uncertainty in the amount and timing of settlement of the liability. We use an expected cash flow approach to measure the amount we recognize as an ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the asset's current license or lease term and expected decommissioning dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related assets. In addition, we accrete the ARO liability to reflect the passage of time. Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets. In accordance with GAAP accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal.

AROs as of December 31, 2025 are described further in Note 21.

OTHER ACCOUNTING MATTERS

See Note 3 for information relating to the following new accounting standards:

- ASU 2023-09, Income Taxes: Improvements to Income Tax Disclosures, adopted on December 31, 2025. See Note 5.

- ASU 2024-03, Income Statement Reporting: Expense Disaggregation Disclosures, effective for us on December 31, 2027, with early adoption permitted.

- ASU 2025-03, Business Combinations and Consolidation: Determining the Accounting Acquirer in the Acquisition of a VIE, effective for us on January 1, 2027, with early adoption permitted.

- ASU 2025-06, Intangibles—Goodwill and Other—Internal-Use Software: Targeted Improvements to the Accounting for Internal-Use Software, effective for us on January 1, 2028, with early adoption permitted.

- ASU 2025-09, Derivatives and Hedging: Hedge Accounting Improvements, effective for us on January 1, 2027, with early adoption permitted.

- ASU 2025-10, Government Grants: Accounting for Government Grants Received by Business Entities, effective for us on January 1, 2029, with early adoption permitted.

MARKET AND CREDIT RISKS

Market Risks

Our operations include managing market risks related to changes in interest rates, commodity prices, investments held by our nuclear decommissioning trusts, other special use funds and benefit plan assets.

Interest Rate and Equity Risk

We have exposure to changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and the market value of fixed income securities held by our nuclear decommissioning trust, other special use funds (see Notes 17 and 18), and benefit plan assets. The nuclear decommissioning trust, other special use funds and benefit plan assets also have risks associated with the changing market value of their equity and other non-fixed income investments. Nuclear decommissioning, coal reclamation, and benefit plan costs are recovered in regulated electricity prices.

The tables below present contractual balances of our consolidated long-term and short-term debt at the expected maturity dates, as well as the fair value of those instruments on December 31, 2025 and 2024. If variable interest rates were to increase by 10% from the December 31, 2025, levels, it would not have a material effect on Pinnacle West Consolidated or APS Consolidated annual interest expense. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2025 and 2024 (dollars in millions):

Pinnacle West Consolidated

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2025	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**
2026	3.98 %	$ 757	5.10 %	$ 350	2.55 %	$ 250
2027	—	—	—	—	4.10 %	825
2028	—	—	—	—	4.90 %	400
2029	—	—	3.52 %	164	2.60 %	405
2030	—	—	—	—	5.15 %	400
Years thereafter	—	—	—	—	4.62 %	7,075
Total		$ 757		$ 514		$ 9,355
Fair value		$ 757		$ 514		$ 8,651

2024	Short-Term Debt Interest Rates	Short-Term Debt Amount	Variable-Rate Long-Term Debt Interest Rates	Variable-Rate Long-Term Debt Amount	Fixed-Rate Long-Term Debt Interest Rates	Fixed-Rate Long-Term Debt Amount
2025	4.90 %	$ 568	—	$ —	1.99 %	$ 800
2026	—	—	5.88 %	350	2.55 %	250
2027	—	—	—	—	4.10 %	825
2028	—	—	—	—	—	—
2029	—	—	4.01 %	164	2.60 %	405
Years thereafter	—	—		—	4.31 %	6,125
Total		$ 568		$ 514		$ 8,405
Fair value		$ 568		$ 514		$ 7,405

The tables below present contractual balances of APS's long-term and short-term debt at the expected maturity dates, as well as the fair value of those instruments on December 31, 2025, and 2024. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2025, and 2024 (dollars in millions):

APS Consolidated

2025	Short-Term Debt Interest Rates	Short-Term Debt Amount	Variable-Rate Long-Term Debt Interest Rates	Variable-Rate Long-Term Debt Amount	Fixed-Rate Long-Term Debt Interest Rates	Fixed-Rate Long-Term Debt Amount
2026	3.83 %	$ 507	—	$ —	2.55 %	$ 250
2027	—	—	—	—	2.95 %	300
2028	—	—	—	—	—	—
2029	—	—	3.52 %	164	2.60 %	405
2030	—	—	—	—	—	—
Years thereafter	—	—	—	—	4.62 %	7,075
Total		$ 507		$ 164		$ 8,030
Fair value		$ 507		$ 164		$ 7,269

2024	Short-Term Debt Interest Rates	Short-Term Debt Amount	Variable-Rate Long-Term Debt Interest Rates	Variable-Rate Long-Term Debt Amount	Fixed-Rate Long-Term Debt Interest Rates	Fixed-Rate Long-Term Debt Amount
2025	4.62 %	$ 340	—	$ —	3.15 %	$ 300
2026	—	—	—	—	2.55 %	250
2027	—	—	—	—	2.95 %	300
2028	—	—	—	—	—	—
2029	—	—	4.01 %	164	2.60 %	405
Years thereafter	—	—	—	—	4.31 %	6,125
Total		$ 340		$ 164		$ 7,380
Fair value		$ 340		$ 164		$ 6,361

Commodity Price Risk

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity and natural gas. Our risk management committee, consisting of officers and key management personnel, oversees company-wide energy risk management activities to ensure compliance with our stated energy risk management policies. We manage risks associated with these market fluctuations by utilizing various commodity instruments that may qualify as derivatives, including futures, forwards, options, and swaps. As part of our risk management program, we use such instruments to hedge purchases and sales of electricity and natural gas. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities.

The following table shows the net pretax changes in mark-to-market of our energy derivative positions (dollars in millions):

	December 31, 2025	December 31, 2024
Mark-to-market of net positions at beginning of year	$ (42)	$ (120)
Decrease in regulatory asset	16	78
Mark-to-market of net positions at end of year	$ (26)	$ (42)

The table below shows the fair value of maturities of our energy derivative contracts (dollars in millions) at December 31, 2025, by maturities and by the type of valuation that is performed to calculate the fair values, classified in their entirety based on the lowest level of input that is significant to the fair value measurement. See Note 1, "Derivative Accounting" and "Fair Value Measurements," for more discussion of our valuation methods.

Source of Fair Value	2026	2027	2028	2029	2030	Total Fair Value
Observable prices provided by other external sources	$ (6)	$ 6	$ (2)	$ —	$ —	$ (2)
Prices based on unobservable inputs	(24)	—	—	—	—	(24)
Total by maturity	$ (30)	$ 6	$ (2)	$ —	$ —	$ (26)

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management assets and liabilities included on Pinnacle West's Consolidated Balance Sheets (dollars in millions):

	December 31, 2025 Gain (Loss)		December 31, 2024 Gain (Loss)	
	Price Up 10%	Price Down 10%	Price Up 10%	Price Down 10%
Mark-to-market changes reported in:				
Regulatory asset (liability) (a)				
Electricity	$ 3	$ (3)	$ 3	$ (3)
Natural gas	58	(58)	75	(75)
Total	$ 61	$ (61)	$ 78	$ (78)

(a) These contracts are economic hedges of our forecasted purchases of natural gas and electricity. The impact of these hypothetical price movements would substantially offset the impact that these same price movements would have on the physical exposures being hedged. To the extent the amounts are eligible for inclusion in the PSA, the amounts are recorded as either a regulatory asset or liability.

Credit Risk

We are exposed to losses in the event of non-performance or non-payment by counterparties. See Note 13 for a discussion of our credit valuation adjustment policy.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Market and Credit Risks" in Part II, Item 7 above for a discussion of quantitative and qualitative disclosures about market risks.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING (PINNACLE WEST CAPITAL CORPORATION)

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f), for Pinnacle West Capital Corporation. Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under this framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2025. The effectiveness of our internal control over financial reporting as of December 31, 2025, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein and also relates to the Company's consolidated financial statements.

February 25, 2026

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of
Pinnacle West Capital Corporation
Phoenix, Arizona

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of income, 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 schedule listed in the Index at Item 15 (collectively referred to as the "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 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 COSO.

Basis for Opinions

The Company's management is responsible for these 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 the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion 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 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 financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to 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. 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 (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.

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.

Regulatory Accounting — Impact of Rate Regulation on the Financial Statements — Refer to Notes 1 and 8 to the financial statements

Critical Audit Matter Description

Arizona Public Service Company ("APS"), which is a wholly-owned subsidiary of the Company, is subject to rate regulation by the Arizona Corporation Commission (the "ACC"), which has jurisdiction with respect to the rates charged by public service utilities in Arizona. 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, such as property, plant and equipment; deferred fuel and purchased power regulatory asset; other regulatory assets; regulatory liabilities (short-term and long-term); operating revenues; fuel and purchased power expense; operations and maintenance expense; and depreciation and amortization expense.

The ACC's rate-making policies are premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the ACC in the future will impact the accounting for regulated operations, including decisions about the amount of allowable deferred costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the ACC will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment. If future recovery of regulatory assets ceases to be probable or a disallowance becomes probable, it would result in a charge to earnings.

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 high degree of subjectivity involved in assessing the impact of future regulatory rate orders on the financial statements. Management judgments include continually assessing the likelihood of future recovery of regulatory assets and/or a disallowance of part of the cost of recently completed plant, by considering factors such as applicable regulatory environment changes, and recent rate orders specific to APS and to other regulated entities in the same jurisdiction. Management judgments also include assessing the impact of potential ACC-ordered refunds to customers on regulatory liabilities. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the ACC, 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 ACC 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 of recently completed plant and costs deferred as regulatory assets and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the initial recognition of amounts as property, plant, and equipment; 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 APS's disclosures related to regulatory accounting, specifically the impact of rate regulation on the financial statements, including the balances recorded and regulatory developments.
- We read relevant regulatory rate orders issued by the ACC for APS and other public utilities in Arizona, regulatory statutes, interpretations, procedural memorandums, filings made by intervenors, and 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 ACC's treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory assets and liabilities for completeness.
- For regulatory matters in process, we inspected APS's filings with the ACC and the filings with the ACC by intervenors that may impact the APS's future rates, for evidence that might contradict management's assertions.

- We obtained an analysis from management and internal legal counsel regarding the 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

Tempe, Arizona
February 25, 2026

We have served as the Company's auditor since 1932.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(dollars and shares in thousands, except per share amounts)

	Year Ended December 31,		
	2025	2024	2023
OPERATING REVENUES (Note 4)	$ 5,339,939	$ 5,124,915	$ 4,695,991
OPERATING EXPENSES			
Fuel and purchased power	1,933,420	1,822,566	1,792,657
Operations and maintenance	1,185,065	1,165,156	1,058,725
Depreciation and amortization	915,343	895,346	794,043
Taxes other than income taxes	234,797	227,395	224,013
Other expense	3,684	2,389	1,913
Total	4,272,309	4,112,852	3,871,351
OPERATING INCOME	1,067,630	1,012,063	824,640
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	61,146	38,620	53,118
Pension and other postretirement non-service credits, net (Note 9)	12,420	48,870	40,648
Other income (Note 15)	49,406	48,614	33,666
Other expense (Note 15)	(30,265)	(34,136)	(25,056)
Total	92,707	101,968	102,376
INTEREST EXPENSE			
Interest charges	469,701	425,742	374,887
Allowance for borrowed funds used during construction (Note 1)	(47,733)	(48,270)	(43,564)
Total	421,968	377,472	331,323
Income Before Income Taxes	738,369	736,559	595,693
Income Taxes (Note 5)	106,726	110,529	76,912
NET INCOME	631,643	626,030	518,781
Less: Net income attributable to noncontrolling interests (Note 12)	15,112	17,224	17,224
Net Income Attributable to Common Shareholders	$ 616,531	$ 608,806	$ 501,557
Weighted-average common shares outstanding — basic	119,687	113,846	113,442
Weighted-average common shares outstanding — diluted	121,971	116,232	113,804
Earnings Per Weighted-Average Common Share Outstanding			
Net income attributable to common shareholders — basic	$ 5.15	$ 5.35	$ 4.42
Net income attributable to common shareholders — diluted	$ 5.05	$ 5.24	$ 4.41

The accompanying notes are an integral part of the financial statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(dollars in thousands)

	Year Ended December 31,		
	2025	2024	2023
NET INCOME	$ 631,643	$ 626,030	$ 518,781
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments net unrealized gain (loss), net of tax benefit (expense) of $49, $(292), and $234	(147)	(891)	713
Pension and other postretirement benefits activity, net of tax benefit (expense) of $484, $(1,073), and $801 (Note 9)	(1,319)	3,093	(2,422)
Total other comprehensive income (loss)	(1,466)	2,202	(1,709)
COMPREHENSIVE INCOME	630,177	628,232	517,072
Less: Comprehensive income attributable to noncontrolling interests	15,112	17,224	17,224
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 615,065	$ 611,008	$ 499,848

The accompanying notes are an integral part of the financial statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2025	December 31, 2024
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 6,604	$ 3,838
Customer and other receivables	579,831	525,608
Accrued unbilled revenues (Note 4)	173,692	176,903
Allowance for doubtful accounts (Note 4)	(25,495)	(24,849)
Materials and supplies (at average cost)	546,329	469,022
Income tax receivable (Note 5)	5,979	—
Fossil fuel (at average cost)	18,824	32,420
Assets from risk management activities (Note 13)	3,250	10,578
Deferred fuel and purchased power regulatory asset (Note 8)	149,068	287,597
Other regulatory assets (Note 8)	136,941	133,372
Other current assets	108,686	74,915
Total current assets	1,703,709	1,689,404
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 17 and 18)	1,414,166	1,282,845
Other special use funds (Notes 17 and 18)	434,827	408,357
Assets from risk management activities (Note 13)	5,137	5,980
Other assets	144,997	115,095
Total investments and other assets	1,999,127	1,812,277
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 7 and 11)		
Plant in service and held for future use	27,370,296	25,860,950
Accumulated depreciation and amortization	(9,012,021)	(9,027,426)
Net	18,358,275	16,833,524
Construction work in progress	1,649,542	1,592,659
Palo Verde sale leaseback, net of accumulated depreciation of $110,886 and $268,894 (Note 12)	32,035	82,556
Intangible assets, net of accumulated amortization of $1,057,812 and $925,880	575,978	591,310
Nuclear fuel, net of accumulated amortization of $111,096 and $115,894	104,274	97,850
Total property, plant and equipment	20,720,104	19,197,899
DEFERRED DEBITS		
Regulatory assets (Notes 1, 5, 8 and 9)	1,463,357	1,389,489
Operating lease right-of-use assets (Note 20)	3,649,669	1,605,463
Assets for other postretirement benefits (Note 9)	399,334	342,102
Other	96,299	66,126
Total deferred debits	5,608,659	3,403,180
TOTAL ASSETS	$ 30,031,599	$ 26,102,760

The accompanying notes are an integral part of the financial statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2025	December 31, 2024
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 680,203	$ 485,426
Accrued taxes	186,605	175,863
Accrued interest	105,637	81,799
Common dividends payable	110,022	106,592
Short-term borrowings (Note 6)	757,005	568,450
Current maturities of long-term debt (Note 7)	600,000	800,000
Customer deposits	63,776	44,345
Liabilities from risk management activities (Note 13)	35,141	52,340
Liabilities for asset retirements (Note 21)	71,698	50,009
Operating lease liabilities (Note 20)	188,586	100,367
Regulatory liabilities (Note 8)	210,909	206,955
Other current liabilities	151,444	171,651
Total current liabilities	3,161,026	2,843,797
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 7)	9,205,676	8,058,648
DEFERRED CREDITS AND OTHER		
Liabilities from risk management activities (Note 13)	1,495	9,446
Deferred income taxes (Note 5)	2,470,932	2,444,473
Regulatory liabilities (Notes 1, 5, 8 and 9)	1,736,121	1,855,278
Liabilities for pension benefits (Note 9)	167,636	139,317
Liabilities for asset retirements (Note 21)	1,198,601	1,096,577
Customer advances	632,169	569,343
Coal mine reclamation	159,587	171,483
Deferred investment tax credit	308,261	249,490
Unrecognized tax benefits (Note 5)	105,484	44,233
Operating lease liabilities (Note 20)	3,548,365	1,520,877
Other	249,171	242,320
Total deferred credits and other	10,577,822	8,342,837
COMMITMENTS AND CONTINGENCIES (Note 14)		
EQUITY		
Common stock, no par value; authorized 300,000,000 and 150,000,000 shares authorized at respective dates, 120,950,839 and 119,143,782 shares issued at respective dates	3,231,372	3,121,617
Treasury stock at cost; 46,968 and 46,968 shares at respective dates	(3,323)	(3,323)
Total common stock	3,228,049	3,118,294
Retained earnings	3,850,817	3,666,959
Accumulated other comprehensive loss (Note 19)	(32,408)	(30,942)
Total shareholders’ equity	7,046,458	6,754,311
Noncontrolling interests (Note 12)	40,617	103,167
Total equity	7,087,075	6,857,478
TOTAL LIABILITIES AND EQUITY	$ 30,031,599	$ 26,102,760

The accompanying notes are an integral part of the financial statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(dollars in thousands)

	Year Ended December 31,		
	2025	2024	2023
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 631,643	$ 626,030	$ 518,781
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on sale relating to BCE	—	(22,988)	(6,423)
Depreciation and amortization including nuclear fuel	969,615	956,184	854,136
Allowance for equity funds used during construction	(61,146)	(38,620)	(53,118)
Deferred income taxes	(50,850)	(20,923)	(24,310)
Deferred investment tax credit	58,772	(8,253)	77,065
Change in derivative instruments fair value	—	—	(777)
Stock compensation	27,457	23,532	17,341
Changes in current assets and liabilities:			
Customer and other receivables	(51,275)	(12,696)	(61,983)
Accrued unbilled revenues	3,211	(9,350)	(2,789)
Materials, supplies and fossil fuel	(63,711)	(7,895)	(42,911)
Income tax receivable	(5,979)	332	13,754
Deferred fuel and purchased power	(324,482)	(250,288)	(549,877)
Deferred fuel and purchased power amortization	463,011	425,886	547,243
Other current assets	(42,991)	(50,225)	(19,550)
Accounts payable	171,138	(7,214)	(75,623)
Accrued taxes	10,742	9,030	2,393
Other current liabilities	18,714	47,329	40,510
Change in unrecognized tax benefits	81,090	75	1,177
Change in long-term regulatory assets	91,373	43,305	53,112
Change in long-term regulatory liabilities	37,205	9,416	28,495
Change in other long-term assets	(283,507)	(132,563)	(195,598)
Change in operating lease assets	151,522	98,214	90,525
Change in other long-term liabilities	138,934	24,719	61,903
Change in operating lease liabilities	(165,391)	(93,214)	(65,779)
Net cash provided by operating activities	1,805,095	1,609,823	1,207,697
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(2,624,618)	(2,249,195)	(1,846,370)
Contributions in aid of construction	306,380	311,358	180,866
Proceeds from sale relating to BCE	—	84,322	23,400
Allowance for borrowed funds used during construction	(47,733)	(48,270)	(43,564)
Proceeds from nuclear decommissioning trust sales and other special use funds	1,855,200	1,686,094	1,679,722
Investment in nuclear decommissioning trust and other special use funds	(1,858,991)	(1,709,526)	(1,681,845)
Other	(8,912)	(8,413)	(6,458)
Net cash used for investing activities	(2,378,674)	(1,933,630)	(1,694,249)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	1,742,754	1,313,229	689,349
Repayment of long-term debt	(800,000)	(875,000)	(32,740)
Short-term borrowings and (repayments) — net	213,555	(241,050)	241,900
Short-term debt borrowings under term loan facility	575,000	550,000	—
Short-term debt repayments under term loan facility	(600,000)	(350,000)	—
Dividends paid on common stock	(422,792)	(394,663)	(386,486)
Common stock equity issuance and purchases — net	84,613	341,429	(4,093)
Palo Verde sale leaseback noncontrolling interest acquisition	(198,744)	—	—
Capital activities by noncontrolling interests	(18,041)	(21,255)	(21,255)
Net cash provided by financing activities	576,345	322,690	486,675
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2,766	(1,117)	123
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	3,838	4,955	4,832
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 6,604	$ 3,838	$ 4,955

The accompanying notes are an integral part of the financial statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(dollars in thousands, except per share amounts)

	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, December 31, 2022	113,247,189	$2,724,740	(73,613)	$ (5,005)	$3,360,347	$ (31,435)	$ 111,229	$ 6,159,876
Net income		—		—	501,557	—	17,224	518,781
Other comprehensive loss		—		—	—	(1,709)	—	(1,709)
Dividends on common stock ($3.49 per share)		—		—	(395,585)	—	—	(395,585)
Issuance of common stock	290,500	27,936		—	—	—	—	27,936
Purchase of treasury stock (a)		—	(72,180)	(5,466)	—	—	—	(5,466)
Reissuance of treasury stock for stock-based compensation and other		—	32,521	2,287	—	—	—	2,287
Capital activities by noncontrolling interests		—		—	—	—	(21,255)	(21,255)
Other		—		(1)	(2)	—	—	(3)
Balance, December 31, 2023	113,537,689	2,752,676	(113,272)	(8,185)	3,466,317	(33,144)	107,198	6,284,862
Net income		—		—	608,806	—	17,224	626,030
Other comprehensive income		—		—	—	2,202	—	2,202
Dividends on common stock ($3.55 per share)		—		—	(408,162)	—	—	(408,162)
Issuance of common stock (b)	5,606,093	368,941		—	—	—	—	368,941
Purchase of treasury stock (a)		—	(71,008)	(4,907)	—	—	—	(4,907)
Reissuance of treasury stock for stock-based compensation and other		—	137,312	9,768	—	—	—	9,768
Capital activities by noncontrolling interests		—		—	—	—	(21,255)	(21,255)
Other		—		1	(2)	—	—	(1)
Balance, December 31, 2024	119,143,782	3,121,617	(46,968)	(3,323)	3,666,959	(30,942)	103,167	6,857,478
Net income		—		—	616,531	—	15,112	631,643
Other comprehensive loss		—		—	—	(1,466)	—	(1,466)
Dividends on common stock ($3.61 per share)		—		—	(432,671)	—	—	(432,671)
Issuance of common stock (b)	1,807,057	109,755			—	—	—	109,755
Capital activities by noncontrolling interests		—		—	—	—	(18,041)	(18,041)
Deconsolidation of noncontrolling interests (c)		—		—	—	—	(59,621)	(59,621)
Other		—		—	(2)	—	—	(2)
Balance, December 31, 2025	120,950,839	$3,231,372	(46,968)	$ (3,323)	$3,850,817	$ (32,408)	$ 40,617	$ 7,087,075

(a) Primarily represents shares of common stock withheld from certain stock awards for tax purposes.
(b) See Note 16 for information related to our equity forward sale agreements.
(c) See Note 12 for information related to the Palo Verde sale leaseback purchases.

The accompanying notes are an integral part of the financial statements.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING (ARIZONA PUBLIC SERVICE COMPANY)

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f), for APS. Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under this framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2025. The effectiveness of our internal control over financial reporting as of December 31, 2025, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein and also relates to the Company's financial statements.

February 25, 2026

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholder and the Board of Directors of
Arizona Public Service Company
Phoenix, Arizona

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Arizona Public Service Company and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of income, 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 (collectively referred to as the "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 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 COSO.

Basis for Opinions

The Company's management is responsible for these 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 the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion 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 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 financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to 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. 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 (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.

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.

Regulatory Accounting – Impact of Rate Regulation on the Financial Statements — Refer to Notes 1 and 8 to the financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by the Arizona Corporation Commission (the "ACC"), which has jurisdiction with respect to the rates charged by public service utilities in Arizona. 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, such as property, plant and equipment; deferred fuel and purchased power regulatory asset; other regulatory assets; regulatory liabilities (short-term and long-term); operating revenues; fuel and purchased power expense; operations and maintenance expense; and depreciation and amortization expense.

The ACC's rate-making policies are premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the ACC in the future will impact the accounting for regulated operations, including decisions about the amount of allowable deferred costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the ACC will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment. If future recovery of regulatory assets ceases to be probable or a disallowance becomes probable, it would result in a charge to earnings.

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 high degree of subjectivity involved in assessing the impact of future regulatory rate orders on the financial statements. Management judgments include continually assessing the likelihood of future recovery of regulatory assets and/or a disallowance of part of the cost of recently completed plant, by considering factors such as applicable regulatory environment changes, and recent rate orders specific to APS and to other regulated entities in the same jurisdiction. Management judgments also include assessing the impact of potential ACC-ordered refunds to customers on regulatory liabilities. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the ACC, 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 ACC 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 of recently completed plant and costs deferred as regulatory assets and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the initial recognition of amounts as property, plant, and equipment; 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 regulatory accounting, specifically the impact of rate regulation on the financial statements, including the balances recorded and regulatory developments.
- We read relevant regulatory rate orders issued by the ACC for the Company and other public utilities in Arizona, regulatory statutes, interpretations, procedural memorandums, filings made by intervenors, and 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 ACC's treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory assets and liabilities for completeness.
- For regulatory matters in process, we inspected the Company's filings with the ACC and the filings with the regulatory authorities by intervenors that may impact the Company's future rates, for evidence that might contradict managements assertions.

- We obtained an analysis from management and internal legal counsel regarding the 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

Tempe, Arizona
February 25, 2026

We have served as the Company's auditor since 1932.

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(dollars in thousands)

	Year Ended December 31,		
	2025	2024	2023
OPERATING REVENUES (Note 4)	$5,339,939	$5,124,915	$4,695,991
OPERATING EXPENSES			
Fuel and purchased power	1,933,420	1,822,566	1,792,657
Operations and maintenance	1,177,089	1,158,634	1,043,570
Depreciation and amortization	915,275	895,171	793,958
Taxes other than income taxes	234,733	227,307	223,962
Other expense	3,684	2,389	1,913
Total	4,264,201	4,106,067	3,856,060
OPERATING INCOME	1,075,738	1,018,848	839,931
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	61,146	38,620	53,118
Pension and other postretirement non-service credits, net (Note 9)	13,365	49,489	41,577
Other income (Note 15)	16,214	21,094	27,072
Other expense (Note 15)	(26,382)	(29,698)	(18,264)
Total	64,343	79,505	103,503
INTEREST EXPENSE			
Interest charges	379,468	360,481	323,719
Allowance for borrowed funds used during construction (Note 1)	(47,733)	(48,270)	(39,030)
Total	331,735	312,211	284,689
Income Before Income Taxes	808,346	786,142	658,745
Income Taxes (Note 5)	125,919	126,993	94,184
NET INCOME	682,427	659,149	564,561
Less: Net income attributable to noncontrolling interests (Note 12)	15,112	17,224	17,224
Net Income Attributable to Common Shareholder	$ 667,315	$ 641,925	$ 547,337

The accompanying notes are an integral part of the financial statements.

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(dollars in thousands)

	Year Ended December 31,		
	2025	2024	2023
NET INCOME	$ 682,427	$ 659,149	$ 564,561
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Pension and other postretirement benefits activity, net of tax benefit (expense) of $440, $(1,022), and $536 (Note 9)	(1,341)	3,103	(1,623)
Total other comprehensive income (loss)	(1,341)	3,103	(1,623)
COMPREHENSIVE INCOME	681,086	662,252	562,938
Less: Comprehensive income attributable to noncontrolling interests	15,112	17,224	17,224
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 665,974	$ 645,028	$ 545,714

The accompanying notes are an integral part of the financial statements.

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ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2025	December 31, 2024
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 4,143	$ 3,815
Customer and other receivables	592,146	522,886
Accrued unbilled revenues (Note 4)	173,692	176,903
Allowance for doubtful accounts (Note 4)	(25,495)	(24,849)
Materials and supplies (at average cost)	546,329	469,022
Income tax receivable (Note 5)	—	5,463
Fossil fuel (at average cost)	18,824	32,420
Assets from risk management activities (Note 13)	3,250	10,578
Deferred fuel and purchased power regulatory asset (Note 8)	149,068	287,597
Other regulatory assets (Note 8)	136,941	133,372
Other current assets	102,820	65,754
Total current assets	1,701,718	1,682,961
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 17 and 18)	1,414,166	1,282,845
Other special use funds (Notes 17 and 18)	394,514	374,156
Assets from risk management activities (Note 13)	5,137	5,980
Other assets	50,912	49,673
Total investments and other assets	1,864,729	1,712,654
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 7 and 11)		
Plant in service and held for future use	27,369,414	25,860,068
Accumulated depreciation and amortization	(9,011,139)	(9,026,544)
Net	18,358,275	16,833,524
Construction work in progress	1,649,542	1,592,659
Palo Verde sale leaseback, net of accumulated depreciation of $110,886 and $268,894 (Note 12)	32,035	82,556
Intangible assets, net of accumulated amortization of $1,057,812 and $925,880	575,823	591,154
Nuclear fuel, net of accumulated amortization of $111,096 and $115,894	104,274	97,850
Total property, plant and equipment	20,719,949	19,197,743
DEFERRED DEBITS		
Regulatory assets (Notes 1, 5, 8 and 9)	1,463,357	1,389,489
Operating lease right-of-use assets (Note 20)	3,648,658	1,604,324
Assets for other postretirement benefits (Note 9)	392,348	335,458
Other	95,600	65,606
Total deferred debits	5,599,963	3,394,877
TOTAL ASSETS	$ 29,886,359	$ 25,988,235

The accompanying notes are an integral part of the financial statements.

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2025	December 31, 2024
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 672,518	$ 481,955
Accrued taxes	176,968	181,698
Accrued interest	98,434	79,308
Common dividends payable	110,000	107,200
Short-term borrowings (Note 6)	507,305	339,900
Current maturities of long-term debt (Note 7)	250,000	300,000
Customer deposits	63,776	44,345
Liabilities from risk management activities (Note 13)	35,141	52,340
Liabilities for asset retirements (Note 21)	71,698	50,009
Operating lease liabilities (Note 20)	188,437	100,229
Regulatory liabilities (Note 8)	210,909	206,955
Other current liabilities	159,039	177,019
Total current liabilities	2,544,225	2,120,958
DEFERRED CREDITS AND OTHER		
Liabilities from risk management activities (Note 13)	1,495	9,446
Deferred income taxes (Note 5)	2,427,765	2,419,937
Regulatory liabilities (Notes 1, 5, 8 and 9)	1,736,121	1,855,278
Liabilities for pension benefits (Note 9)	164,892	134,855
Liabilities for asset retirements (Note 21)	1,198,601	1,096,577
Customer advances	632,169	569,343
Coal mine reclamation	159,587	171,483
Deferred investment tax credit	308,261	249,490
Unrecognized tax benefits (Note 5)	121,066	48,725
Operating lease liabilities (Note 20)	3,547,321	1,519,683
Other	232,661	225,250
Total deferred credits and other	10,529,939	8,300,067
COMMITMENTS AND CONTINGENCIES (Note 14)		
CAPITALIZATION		
Common stock	178,162	178,162
Additional paid-in capital	4,491,696	4,116,696
Retained earnings	4,227,237	3,992,423
Accumulated other comprehensive loss (Note 19)	(15,457)	(14,116)
Total shareholder equity	8,881,638	8,273,165
Noncontrolling interests (Note 12)	40,617	103,167
Total equity	8,922,255	8,376,332
Long-term debt less current maturities (Note 7)	7,889,940	7,190,878
Total capitalization	16,812,195	15,567,210
TOTAL LIABILITIES AND EQUITY	$ 29,886,359	$ 25,988,235

The accompanying notes are an integral part of the financial statements.

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(dollars in thousands)

	Year Ended December 31,		
	2025	2024	2023
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 682,427	$ 659,149	$ 564,561
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	969,547	956,009	854,051
Allowance for equity funds used during construction	(61,146)	(38,620)	(53,118)
Deferred income taxes	(58,483)	(56,461)	(10,314)
Deferred investment tax credit	58,772	(8,253)	77,065
Changes in current assets and liabilities:			
Customer and other receivables	(66,312)	(13,570)	(62,716)
Accrued unbilled revenues	3,211	(9,350)	(2,789)
Materials, supplies and fossil fuel	(63,711)	(7,895)	(42,911)
Income tax receivable	5,463	(5,463)	1,102
Deferred fuel and purchased power	(324,482)	(250,288)	(549,877)
Deferred fuel and purchased power amortization	463,011	425,886	547,243
Other current assets	(46,286)	(14,704)	(20,243)
Accounts payable	166,924	(2,500)	(70,622)
Accrued taxes	(4,730)	19,410	5,542
Other current liabilities	16,162	31,982	62,212
Change in unrecognized tax benefits	81,090	75	1,177
Change in long-term regulatory assets	91,373	43,305	53,112
Change in long-term regulatory liabilities	37,205	9,416	28,495
Change in other long-term assets	(256,960)	(159,940)	(188,483)
Change in operating lease assets	151,394	97,989	90,234
Change in other long-term liabilities	147,447	27,127	57,397
Change in operating lease liabilities	(165,241)	(93,076)	(65,482)
Net cash provided by operating activities	1,826,675	1,610,228	1,275,636
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(2,624,618)	(2,249,195)	(1,825,585)
Contributions in aid of construction	306,380	311,358	180,866
Allowance for borrowed funds used during construction	(47,733)	(48,270)	(39,030)
Proceeds from nuclear decommissioning trust sales and other special use funds	1,803,767	1,686,094	1,679,722
Investment in nuclear decommissioning trust and other special use funds	(1,807,558)	(1,684,526)	(1,681,845)
Other	145	(1,660)	(1,397)
Net cash used for investing activities	(2,369,617)	(1,986,199)	(1,687,269)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	947,350	445,842	496,025
Repayment of long-term debt	(300,000)	(250,000)	—
Short-term borrowings and (repayments) — net	167,405	(192,950)	180,970
Short-term debt borrowings under term loan facility	400,000	350,000	—
Short-term debt repayments under term loan facility	(400,000)	(350,000)	—
Dividends paid on common stock	(429,700)	(401,400)	(393,600)
Equity infusion from Pinnacle West	375,000	795,000	150,000
Palo Verde sale leaseback noncontrolling interest acquisition	(198,744)	—	—
Capital activities by noncontrolling interests	(18,041)	(21,255)	(21,255)
Net cash provided by financing activities	543,270	375,237	412,140
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	328	(734)	507
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	3,815	4,549	4,042
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 4,143	$ 3,815	$ 4,549

The accompanying notes are an integral part of the financial statements.

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(dollars in thousands)

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, December 31, 2022	71,264,947	$ 178,162	$ 3,171,696	$ 3,607,464	$ (15,596)	$ 111,229	$ 7,052,955
Equity infusion from Pinnacle West		—	150,000	—	—	—	150,000
Net income		—	—	547,337	—	17,224	564,561
Other comprehensive loss		—	—	—	(1,623)	—	(1,623)
Dividends on common stock		—	—	(395,500)	—	—	(395,500)
Capital activities by noncontrolling interests		—	—	—	—	(21,255)	(21,255)
Other		—	—	(2)	—	—	(2)
Balance, December 31, 2023	71,264,947	178,162	3,321,696	3,759,299	(17,219)	107,198	7,349,136
Equity infusion from Pinnacle West		—	795,000	—	—	—	795,000
Net income		—	—	641,925	—	17,224	659,149
Other comprehensive income		—	—	—	3,103	—	3,103
Dividends on common stock		—	—	(408,800)	—	—	(408,800)
Capital activities by noncontrolling interests		—	—	—	—	(21,255)	(21,255)
Other		—	—	(1)	—	—	(1)
Balance, December 31, 2024	71,264,947	178,162	4,116,696	3,992,423	(14,116)	103,167	8,376,332
Equity infusion from Pinnacle West		—	375,000	—	—	—	375,000
Net income		—	—	667,315	—	15,112	682,427
Other comprehensive loss		—	—	—	(1,341)	—	(1,341)
Dividends on common stock		—	—	(432,500)	—	—	(432,500)
Capital activities by noncontrolling interests		—	—	—	—	(18,041)	(18,041)
Deconsolidation of noncontrolling interests (a)		—	—	—	—	(59,621)	(59,621)
Other		—	—	(1)	—	—	(1)
Balance, December 31, 2025	71,264,947	$ 178,162	$ 4,491,696	$ 4,227,237	$ (15,457)	$ 40,617	$ 8,922,255

(a) See Note 12 for information related to the Palo Verde sale leaseback purchases.

The accompanying notes are an integral part of the financial statements.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Description of Business and Basis of Presentation

Pinnacle West is an investor-owned electric utility holding company that conducts business through its subsidiaries, APS, El Dorado and PNW Power. APS, our wholly-owned subsidiary, is a vertically-integrated electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. APS accounts for essentially all of our revenues and earnings and is expected to continue to do so. El Dorado is a wholly-owned subsidiary that invests in energy-related and Arizona community-based ventures. PNW Power, formed in September 2023, is a wholly-owned subsidiary that holds certain wind and transmission joint-venture investments previously held by BCE. BCE was sold on January 12, 2024 and is no longer included in the Company's consolidated financial statements. See Note 22 for additional information.

Pinnacle West's Consolidated Financial Statements include the accounts of Pinnacle West and our subsidiaries, including APS, El Dorado, and PNW Power, as well as BCE through the date of its sale. Pinnacle West's Consolidated Financial Statements also include the accounts of a VIE relating to the Captive. APS's Consolidated Financial Statements include the accounts of APS and certain VIEs relating to the Palo Verde sale leaseback. In September 2025, APS purchased two of the three leased interests, resulting in the termination of the related lease agreements and discontinuation of VIE consolidation for those leases. See Note 12 for additional information. Intercompany accounts and transactions between the consolidated companies have been eliminated.

We consolidate VIEs for which we are the primary beneficiary. We determine whether we are the primary beneficiary of a VIE through a qualitative analysis that identifies which variable interest holder has the controlling financial interest in the VIE. In performing our primary beneficiary analysis, we consider all relevant facts and circumstances, including the design and activities of the VIE, the terms of the contracts the VIE has entered into, and which parties participated significantly in the design or redesign of the entity. We continually evaluate our primary beneficiary conclusions to determine if changes have occurred which would impact our primary beneficiary assessments. We have determined that APS is the primary beneficiary of a VIE lessor trust relating to the Palo Verde sale leaseback, and therefore APS consolidates this entity. We have also determined that Pinnacle West is the primary beneficiary of a protected captive insurance cell VIE, and therefore Pinnacle West consolidates this insurance cell. See Note 12 for additional information.

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with GAAP. The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Regulatory Accounting

APS is regulated by the ACC and FERC. The accompanying financial statements reflect the rate-making policies of these commissions. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred and are refundable to customers.

Management judgments include continually assessing the likelihood of future recovery of regulatory assets and/or a disallowance of part of the cost of recently completed plant, by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in Arizona and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings. Management judgments also include assessing the impact of potential commission-ordered refunds to customers on regulatory liabilities. See Note 8 for additional information.

Electric Revenues

Revenues primarily consist of activities that are classified as revenues from contracts with customers. Our electric revenues generally represent a single performance obligation delivered over time. We have elected to apply the practical expedient that allows us to recognize revenue based on the amount to which we have a right to invoice for services performed.

We derive electric revenues primarily from sales of electricity to our regulated retail customers. Revenues related to the sale of electricity are generally recognized when service is rendered or electricity is delivered to customers. Unbilled revenues are estimated by applying an average revenue/kWh by customer class to the number of estimated kWhs delivered but not billed. Differences historically between the actual and estimated unbilled revenues are immaterial. We exclude sales taxes and franchise fees on electric revenues from both revenue and taxes other than income taxes.

Revenues from our regulated retail customers and non-derivative instruments are reported on a gross basis on Pinnacle West's Consolidated Statements of Income. In the electricity business, some contracts to purchase electricity are netted against other contracts to sell electricity. This is called a "book-out" and usually occurs for contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow. We net these book-outs, which reduces both wholesale revenues and fuel and purchased power costs.

Certain cost recovery mechanisms may qualify as alternative revenue programs. For alternative revenue programs that meet specified accounting criteria, we recognize revenues when the specific events permitting billing of the additional revenues have been completed. See Notes 4 and 8 for additional information.

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of accounts receivable and accrued unbilled revenues that will ultimately be uncollectible due to credit loss risk. The allowance includes a write-off component that is calculated by applying an estimated write-off factor to retail electric revenues. The write-off factor used to estimate uncollectible accounts is based upon consideration of historical collections experience, the current and forecasted economic environment, changes to our collection policies, and management's best estimate of future collections success. See Note 4 for additional information.

Property, Plant and Equipment

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission, and distribution facilities. We report utility plant at its original cost, which includes:

- material and labor;
- contractor costs;
- capitalized leases;
- construction overhead costs (where applicable); and
- AFUDC.

Pinnacle West's property, plant and equipment included in the December 31, 2025, and 2024 Consolidated Balance Sheets is composed of the following (dollars in thousands):

Property, Plant and Equipment:	**2025**	**2024**
Generation	$ 9,687,466	$ 9,675,576
Transmission	4,451,936	4,135,970
Distribution	9,626,629	9,016,843
Energy storage	515,935	276,954
Solar plant	1,501,301	1,159,385
General plant	1,587,029	1,596,222
Plant in service and held for future use	27,370,296	25,860,950
Accumulated depreciation and amortization	(9,012,021)	(9,027,426)
Net	18,358,275	16,833,524
Construction work in progress	1,649,542	1,592,659
Palo Verde sale leaseback, net of accumulated depreciation	32,035	82,556
Intangible assets, net of accumulated amortization	575,978	591,310
Nuclear fuel, net of accumulated amortization	104,274	97,850
Total property, plant and equipment	$ 20,720,104	$ 19,197,899

Property, plant and equipment balances and classes for APS are not materially different than Pinnacle West.

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant to accumulated depreciation. Liabilities associated with the retirement of tangible long-lived assets are recognized at fair value as incurred and capitalized as part of the related tangible long-lived assets. Accretion of the liability due to the passage of time is an operating expense, and the capitalized cost is depreciated over the useful life of the long-lived asset. See Note 21 for additional information.

APS records a regulatory liability for the excess that has been recovered in regulated rates over the amount calculated in accordance with guidance on accounting for AROs. APS believes it is probable it will recover in regulated rates, the costs calculated in accordance with this accounting guidance.

We record depreciation and amortization on utility plant on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2025, were as follows:

- Steam generation — 21 years;
- Nuclear plant — 30 years;
- Other generation — 16 years;
- Transmission — 34 years;
- Distribution — 33 years;
- Energy storage — 19 years;
- Solar plant — 28 years; and
- General plant — 10 years.

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. Depreciation expense was $732 million in 2025, $723 million in 2024, and $669 million in 2023. For the years 2023 through 2025, the depreciation rates ranged from a low of 1.37% to a high of 12.37%. The weighted-average depreciation rate was 3.06% in 2025, 3.13% in 2024, and 2.98% in 2023.

Asset Retirement Obligations

APS has AROs for its Palo Verde nuclear facilities and certain other generation assets. The Palo Verde ARO primarily relates to final plant decommissioning. This obligation is based on the NRC's requirements for disposal of irradiated property or plant and agreements APS reached with the ACC for final decommissioning of the plant. The non-nuclear generation AROs primarily relate to requirements for removing portions of those plants at the end of the plant life or lease term and coal ash pond closures. Some of APS's transmission and distribution assets have AROs because they are subject to right of way and easement agreements that require final removal. These agreements have a history of uninterrupted renewal that APS expects to continue. As a result, APS cannot reasonably estimate the fair value of the ARO related to such transmission and distribution assets. Additionally, APS has aquifer protection permits for some of its generation sites that require the closure of certain facilities at those sites. See Note 21 for additional information.

Allowance for Funds Used During Construction

AFUDC represents the approximate net composite interest cost of borrowed funds and an allowed return on the equity funds used for construction of regulated utility plant. Both the debt and equity components of AFUDC are non-cash amounts within the Consolidated Statements of Income. Plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation.

AFUDC was calculated by using a composite rate of 6.67% for 2025, 6.23% for 2024, and 6.29% for 2023. APS compounds AFUDC semi-annually and ceases to accrue AFUDC when construction work is completed and the property is placed in service.

Materials and Supplies

APS values materials, supplies and fossil fuel inventory using a weighted-average cost method. APS materials, supplies and fossil fuel inventories are carried at the lower of weighted-average cost or net realizable value, unless evidence indicates that the weighted-average cost (even if in excess of market) will be recovered.

Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, investments held in the nuclear decommissioning trust and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefits plans. Due to the nature of short-term borrowings, the carrying values of these instruments approximate fair value. Fair value measurements may also be applied on a nonrecurring basis to other assets and liabilities in certain circumstances such as impairments. We also disclose fair value information for our long-term debt, which is carried at amortized cost. See Note 7 for additional information.

Fair value is the price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market which we can access for the asset or liability in an orderly transaction between willing market participants on the measurement date. Inputs to fair value may include observable and unobservable data. We maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

We determine fair market value using observable inputs such as actively-quoted prices for identical instruments when available. When actively-quoted prices are not available for the identical instruments, we use other observable inputs, such as prices for similar instruments, other corroborative market information, or prices provided by other external sources. For options, long-term contracts, and other contracts for which observable price data are not available, we use models and other valuation methods, which may incorporate unobservable inputs to determine fair market value.

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. See Note 17 for additional information.

Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and in interest rates. We manage risks associated with market volatility by utilizing various physical and financial instruments including futures, forwards, options, and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and natural gas as well as interest rate risk. The changes in market value of such contracts have a high correlation to price changes in the hedged transactions. We also enter into derivative instruments for economic hedging purposes. Contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow are netted, which reduces both revenues and fuel and purchased power expenses in our Consolidated Statements of Income, but does not impact our financial condition, net income, or cash flows.

We account for our derivative contracts in accordance with derivatives and hedging guidance, which requires all derivatives not qualifying for a scope exception to be measured at fair value on the balance sheet as either assets or liabilities. Transactions with counterparties that have master netting arrangements are reported net on the balance sheet. See Note 13 for additional information.

Loss Contingencies and Environmental Liabilities

Pinnacle West and APS are involved in certain legal and environmental matters that arise in the normal course of business. Contingent losses and environmental liabilities are recorded when it is determined that it is probable that a loss has occurred, and the amount of the loss can be reasonably estimated. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, Pinnacle West and APS record a loss contingency at the minimum amount in the range. Unless otherwise required by GAAP, legal fees are expensed as incurred.

The Captive's contingent losses may include an amount for losses incurred but not reported ("IBNR"). A reserve for IBNR is based upon a loss analysis prepared using actuarial assumptions and techniques. Such liabilities are necessarily based on estimates and the ultimate obligation may be in excess of or less than the estimated liability. The methods for making such estimates and for establishing the resulting liability are continually reviewed, and any adjustments for the review process as well as differences between estimates and ultimate payments are reflected in earnings currently. As of December 31, 2025, no IBNR reserve relating to our Captive has been recorded. See Note 12 for additional information.

Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan for the employees of Pinnacle West and its subsidiaries, in addition to a non-qualified pension plan. We also sponsor another postretirement benefit plan for the employees of Pinnacle West and its subsidiaries that provides medical and life insurance benefits to retired employees. Pension and other postretirement benefit expense are determined by actuarial valuations, based on assumptions that are evaluated annually. See Note 9 for additional information.

Nuclear Fuel

APS amortizes nuclear fuel by using the unit-of-production method. The unit-of-production method is based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units produced within the current period. This calculation determines the current period nuclear fuel expense.

APS also charges nuclear fuel expense for the interim storage and permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel and charged APS

$0.001 per kWh of nuclear generation through May 2014, at which point the DOE reduced the fee to zero. In accordance with a settlement agreement with the DOE in August 2014 for interim storage, we accrued a receivable and an offsetting regulatory liability through the settlement period ended December of 2025. See Note 14 for additional information.

Income Taxes

Income taxes are provided using the asset and liability approach prescribed by guidance relating to accounting for income taxes and are based on currently enacted tax rates. We file our federal income tax return on a consolidated basis, and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each first-tier subsidiary as though each first-tier subsidiary filed a separate income tax return. Any difference between that method and the consolidated (and unitary) income tax liability is attributed to the parent company. The income tax accounts reflect the tax and interest associated with management's estimate of the largest amount of tax benefit that is greater than 50% likely of being realized upon settlement for all known and measurable tax exposures. See Note 5 for additional information.

Cash and Cash Equivalents

We consider cash equivalents to be highly liquid investments with a remaining maturity of three months or less at acquisition.

The following table summarizes supplemental Pinnacle West cash flow information for each of the last three years (dollars in thousands):

	Year Ended December 31,		
	2025	2024	2023
Cash paid during the period for:			
Income taxes, net of refunds/credits	$ 22,754	$ 133,968	$ 8,788
Interest, net of amounts capitalized	388,540	360,349	310,996
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 281,133	$ 257,494	$ 206,269
Dividends accrued but not yet paid	110,022	106,592	99,813
BCE Sale non-cash consideration (Note 22)	—	—	28,262

The following table summarizes supplemental APS cash flow information for each of the last three years (dollars in thousands):

	Year Ended December 31,		
	2025	2024	2023
Cash paid during the period for:			
Income taxes, net of refunds/credits	$ 53,638	$ 179,013	$ 21,734
Interest, net of amounts capitalized	307,520	299,799	267,261
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 281,133	$ 257,494	$ 206,269
Dividends accrued but not yet paid	110,000	107,200	99,800

Intangible Assets

We have separately disclosed intangible assets on Pinnacle West's Consolidated Balance Sheets. The intangible assets relate primarily to APS's internal-use software. We have no goodwill recorded. The intangible assets are amortized over their finite useful lives. Amortization expense was $157 million in 2025, $136 million in 2024, and $90 million in 2023. Estimated amortization expense on existing intangible assets over the next five years is $109 million in 2026, $75 million in 2027, $45 million in 2028, $26 million in 2029, and $14 million in 2030. At December 31, 2025, the weighted-average remaining amortization period for intangible assets was 6 years.

Investments

El Dorado holds investments in both debt and equity securities. Investments in debt securities are generally accounted for as held-to-maturity and investments in equity securities are accounted for using either the equity method (if significant influence) or the measurement alternative for investments without readily determinable fair values (if less than 3-5% ownership and no significant influence). See Note 23 for additional information.

PNW Power holds investments in equity securities. Investments in equity securities are accounted for using either the equity method (if significant influence) or the measurement alternative for investments without readily determinable fair values (if less than 3-5% ownership and no significant influence).

Our investments in the nuclear decommissioning trusts, and other special use funds, are accounted for in accordance with guidance on accounting for investments in debt and equity securities. See Notes 17 and 18 for additional information.

Leases

We determine if an agreement is a lease at contract inception. A lease is defined as a contract, or part of a contract, that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To control the use of an identified asset an entity must have both a right to obtain substantially all of the benefits from the use of the asset and the right to direct the use of the asset. If we determine an agreement is a lease, and we are the lessee, we recognize a right-of-use lease asset and a lease liability at the lease commencement date. Lease liabilities are recognized based on the present value of the fixed lease payments over the lease term. To present value lease liabilities we use the implicit rate in the lease if the information is readily available, otherwise we use our incremental borrowing rate determined at lease commencement. Our incremental borrowing rate is based on the rate of interest we would have to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment. When measuring right-of-use assets and lease liabilities we exclude variable lease payments, other than those that depend on an index or rate or are in-substance fixed payments. For short-term leases with terms of 12 months or less, we do not recognize a right-of-use lease asset or lease liability. We recognize operating lease expense using a straight-line pattern over the periods of use.

APS enters into purchased power contracts that may contain leases. This occurs when a PPA designates a specific power plant or facility, APS obtains substantially all of the economic benefits from the use of the facility and has the right to direct the use of the facility. Purchased power lease contracts may also include energy storage facilities. Lease costs relating to purchased power lease contracts are reported in fuel and purchased power on the Consolidated Statements of Income and are subject to recovery under the PSA or RES. See Note 8 for additional information. We also may enter into lease agreements related to vehicles, office space, land, and other equipment. See Note 20 for additional information.

Preferred Stock

At December 31, 2025, Pinnacle West had 10 million shares of serial preferred stock authorized with no par value, none of which was outstanding, and APS had 15,535,000 shares of various types of preferred stock authorized with $25, $50, and $100 par values, none of which was outstanding.

2. Business Segments

Pinnacle West's reportable business segment is our regulated electricity segment, which consists of retail and wholesale sales supplied under traditional cost-based regulation and related activities and includes electricity generation, transmission, and distribution. Our reportable segment activities are conducted through our wholly-owned subsidiary, APS. All other operating segment activities are insignificant to Pinnacle West.

For segment reporting purposes, Pinnacle West's Chief Executive Officer performs the function of chief operating decision maker ("CODM"). Our CODM uses net income to measure an operating segment's profitability. When assessing the performance of an operating segment, and making decisions about allocating resources, our CODM evaluates net income actual results compared to budget. Net income is also used when implementing strategic initiatives and selecting projects to meet business objectives. Our reportable segment's revenue streams are dependent upon regulated rate recovery, which is a primary factor in how we identify operating segments.

For information on our reportable business segment's revenues, significant expenses, net income (loss), assets, and other reportable segment items, see the APS Consolidated Statements of Income, APS Consolidated Balance Sheets, and APS Consolidated Statements of Cash Flows.

The following table reconciles our reportable segment's revenues, significant expenses, and net income (loss) to the Pinnacle West consolidated amounts (dollars in millions):

	Year Ended December 31,								
	2025			2024			2023		
	Regulated Electricity Segment	Other	Pinnacle West Consolidated	Regulated Electricity Segment	Other	Pinnacle West Consolidated	Regulated Electricity Segment	Other	Pinnacle West Consolidated
Operating revenues	$ 5,340	$ —	$ 5,340	$ 5,125	$ —	$ 5,125	$ 4,696	$ —	$ 4,696
Fuel and purchased power	(1,933)	—	(1,933)	(1,823)	—	(1,823)	(1,793)	—	(1,793)
Operations and maintenance	(1,177)	(8)	(1,185)	(1,159)	(6)	(1,165)	(1,044)	(15)	(1,059)
Depreciation and amortization	(915)	—	(915)	(895)	—	(895)	(794)	—	(794)
Taxes other than income taxes	(235)	—	(235)	(227)	—	(227)	(224)	—	(224)
Allowance for equity funds used during construction	61	—	61	39	—	39	53	—	53
Pension and other postretirement non-service credits, net	13	(1)	12	49	—	49	42	(1)	41
Other income and (expense), net	(14)	30	16	(11)	22	11	7	—	7
Interest charges, net of allowance for borrowed funds used during construction	(332)	(90)	(422)	(312)	(65)	(377)	(285)	(46)	(331)
Income taxes	(126)	19	(107)	(127)	16	(111)	(94)	17	(77)
Less: Net income attributable to noncontrolling interests	(15)	—	(15)	(17)	—	(17)	(17)	—	(17)
Net Income (Loss)	$ 667	$ (50)	$ 617	$ 642	$ (33)	$ 609	$ 547	$ (45)	$ 502

The following table reconciles our reportable segment's assets to the Pinnacle West consolidated amount (dollars in millions):

	December 31, 2025			December 31, 2024		
	Regulated Electricity Segment	Other	Pinnacle West Consolidated	Regulated Electricity Segment	Other	Pinnacle West Consolidated
Total Assets	$ 29,886	$ 146	$ 30,032	$ 25,988	$ 115	$ 26,103

3. New Accounting Standards

ASU 2023-09, Income Taxes: Improvements to Income Tax Disclosures

In December 2023, a new accounting standard was issued that expands disclosures relating to income taxes. The expanded disclosures include a tabular income tax rate reconciliation, disclosure of specific reconciliation categories and reconciling items, the amount of income taxes paid by jurisdiction, and other disclosures. We adopted this standard on December 31, 2025, using a retrospective approach. The adoption of the new standard results in changes to our income tax disclosures, but did not impact our accounting for income taxes or our financial statement results. See Note 5.

ASU 2024-03, Income Statement Reporting: Expense Disaggregation Disclosures

In November 2024, a new accounting standard was issued that requires specific disclosures related to certain costs and expenses. Companies will be required to disclose the amounts of certain cost and expense categories, such as purchases of inventory, employee compensation, depreciation, and amortization, among other disclosures. The new disclosures may be provided in the notes to the financial statements and will not require changes to the face of the Consolidated Statements of Income. The standard becomes effective on December 31, 2027, using either a prospective or retrospective approach, with early adoption permitted. The adoption of the new standard will result in disclosure changes, but will not impact our accounting for such costs and expenses or our financial statement results. We are currently evaluating the transition method and date of adoption we will elect for this new standard.

ASU 2025-03, Business Combinations and Consolidation: Determining the Accounting Acquirer in the Acquisition of a Variable Interest Entity

In May 2025, a new accounting standard was issued that revises the guidance on identifying the accounting acquirer in a business combination in which the acquiree is a VIE that meets the definition of a business. Prior to the issuance of the amended guidance, for certain transactions, the primary beneficiary of the VIE was always required to be deemed the acquirer in the transaction. Under the amended guidance, an entity will now need to complete an assessment of the transaction to determine the acquiring entity and is no longer required to assume that the primary beneficiary is the acquirer in the transaction.

The standard will become effective for us on January 1, 2027, with early adoption permitted. We expect to adopt this guidance on January 1, 2027, and will apply the guidance prospectively to acquisition transactions occurring on and after the adoption date. Upon adoption, we do not expect the guidance will have a material impact on our financial statements. The adoption of this guidance will not impact the APS purchase transactions relating to the Palo Verde sale leaseback VIEs. See Note 12.

ASU 2025-06, Intangibles—Goodwill and Other—Internal-Use Software: Targeted Improvements to the Accounting for Internal-Use Software

In September 2025, a new accounting standard was issued that modernizes the accounting for internal-use software costs by removing references to prescriptive and sequential development stages of a project and replacing them with new criteria used in determining when to start capitalizing software costs. Under the new guidance, capitalization begins when management authorizes and commits to funding the software project and it is probable the project will be completed and used as intended. When determining if a project is probable of being completed, entities must evaluate whether significant development uncertainty exists, such as unresolved technological innovations or unproven features. The new guidance also clarifies that capitalized internal-use software costs are subject to the property, plant, and equipment disclosure requirements.

The standard will become effective for us on January 1, 2028, with early adoption permitted. Entities may adopt the standard using one of the following transition methods: a prospective approach, a retrospective approach, or a modified transition approach that considers in-process projects at the date of adoption. We are currently evaluating the impacts on our financial statements of adopting this new standard and the transition method and date of adoption we will elect. The adoption of this guidance may impact our timing and scope of software costs eligible for capitalization, and may also impact our disclosures relating to software.

ASU 2025-09, Derivatives and Hedging: Hedge Accounting Improvements

In November 2025, a new accounting standard was issued which clarifies certain aspects of the hedge accounting guidance. The new standard is intended to better align hedge accounting with the economics of an entity’s risk management activities, and provides entities the ability to apply hedge accounting to an expanded population of economic hedges of forecasted transactions. The standard will become effective for us on January 1, 2027, applied on a prospective basis. Early adoption is permitted.

We expect to adopt this guidance on January 1, 2027. We are not currently applying hedge accounting, and do not expect the adoption of this guidance will have a material impact on our financial statements.

ASU 2025-10, Government Grants: Accounting for Government Grants Received by Business Entities

In December 2025, a new accounting standard was issued establishing authoritative GAAP guidance on the accounting for government grants received by business entities. Prior to the issuance of this new standard, GAAP did not include guidance relating to government grants received by business entities. The new standard is intended to eliminate diversity in practice and improve the financial reporting and consistency across business entities for government grants. The new standard defines government grants and includes recognition, measurement, presentation, and disclosure requirements. The new standard includes guidance pertaining to both government grants received relating to an asset and government grants received relating to income. The guidance includes recognition thresholds based on the probability of compliance with grant conditions and receipt of the grant, among other accounting requirements. Disclosure requirements include the nature and amounts of government grants received, the conditions attached to the grants, and accounting policies applied.

The new standard will become effective for us on January 1, 2029, with early adoption permitted. Entities may adopt the standard using various transition methods, including a modified prospective approach, a modified retrospective approach, or a retrospective approach to all government grants. We are currently evaluating the impacts on our financial statements of adopting this new standard, as well as the date we will adopt this guidance and the transition method we will elect.

4. Revenue

Sources of Revenue

The following table provides detail of Pinnacle West's consolidated revenues disaggregated by revenue sources (dollars in thousands):

	Year Ended December 31,		
	2025	**2024**	**2023**
Retail Electric Service			
Residential	$ 2,541,320	$ 2,562,822	$ 2,289,196
Non-Residential	2,542,936	2,334,925	2,048,416
Wholesale Energy Sales	108,661	96,857	208,985
Transmission Services for Others	129,667	119,038	138,631
Other Sources	17,355	11,273	10,763
Total Operating Revenues	$ 5,339,939	$ 5,124,915	$ 4,695,991

Retail Electric Revenues

All of Pinnacle West's retail electric revenues are generated by APS. Retail electric revenue is generated by the sale of electricity to our regulated customers within the authorized service territory at tariff rates approved by the ACC and based on customer usage. Revenues related to the sale of electricity are generally recognized when service is rendered, or electricity is delivered to customers. The billing of electricity sales to individual customers is based on the reading of their meters. We obtain customers' meter data on a systematic basis throughout the month, and generally bill customers within a month from when service was provided. Customers are generally required to pay for services within 21 days of when the services are billed. See "Allowance for Doubtful Accounts" discussion below for additional details regarding payment terms. In addition, see the section titled "2025 Rate Case" in Note 8 for details related to proposed adjustments to rate design and modifications of cost allocation methodologies to reduce cross-subsidization by ensuring customers causing production costs are covering those costs through rates.

Wholesale Energy Sales and Transmission Services for Others

All of Pinnacle West's wholesale energy sales and transmission services for others revenues is generated by APS. Revenues from wholesale energy sales and transmission services for others represent energy and transmission sales to wholesale customers. These activities consist of managing fuel and purchased power risks and transmission needs in connection with the cost of serving our retail customers' energy requirements. We may also sell into the wholesale markets generation that is not needed for APS's retail load. Our wholesale activities and tariff rates are regulated by FERC.

Revenue Activities

Our revenues primarily consist of activities that are classified as revenues from contracts with customers. We derive our revenues from contracts with customers primarily from sales of electricity to our regulated retail customers. Revenues from contracts with customers also include wholesale and transmission activities. Our revenues from contracts with customers for the year ended December 31, 2025, 2024 and 2023 were $5,319 million, $5,073 million, and $4,651 million, respectively.

We have certain revenues that do not meet the specific accounting criteria to be classified as revenues from contracts with customers. For the year ended December 31, 2025, 2024, and 2023 our revenues that do not qualify as revenue from contracts with customers were $21 million, $52 million, and $45 million, respectively. This amount includes revenues related to certain regulatory cost recovery mechanisms that are considered alternative revenue programs. We recognize revenue associated with alternative revenue programs when specific events permitting recognition are completed. Certain amounts associated with alternative revenue programs will subsequently be billed to customers; however, we do not reclassify billed amounts into revenue from contracts with customers. See Note 8 for a discussion of our regulatory cost recovery mechanisms.

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of customer and other receivables and accrued unbilled revenues that will ultimately be uncollectible due to credit loss risk. The allowance includes a write-off component that is calculated by applying an estimated write-off factor to retail electric revenues. The write-off factor used to estimate uncollectible accounts is based upon consideration of historical collections experience, the current and forecasted economic environment, changes to our collection policies, and management's best estimate of future collections success. We continue to monitor the impacts of our disconnection policies, payment arrangements, among other considerations impacting our estimated write-off factor, and allowance for doubtful accounts.

The following table provides a rollforward of Pinnacle West's allowance for doubtful accounts (dollars in thousands):

	Year Ended December 31,		
	2025	2024	2023
Balance at beginning of period	$ 24,849	$ 22,433	$ 23,778
Bad debt expense	28,603	35,799	23,399
Actual write-offs	(27,957)	(33,383)	(24,744)
Balance at end of period	$ 25,495	$ 24,849	$ 22,433

5. Income Taxes

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statement purposes. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using currently enacted income tax rates.

APS has recorded regulatory assets and regulatory liabilities related to income taxes on its Consolidated Balance Sheets in accordance with accounting guidance for regulated operations. The regulatory assets are for certain temporary differences, primarily the allowance for equity funds used during construction, ITC basis adjustment and tax expense of Medicare subsidy. The regulatory liabilities primarily relate to the change in income tax rates and deferred taxes resulting from ITCs.

In accordance with regulatory requirements, APS ITCs are deferred and are amortized over the life of the related property with such amortization applied as a credit to reduce current income tax expense in the Statements of Income.

On January 30, 2024, Pinnacle West entered into a tax credit transfer agreement to purchase from Ameresco $23 million of investment tax credits from the BCE Los Alamitos project for $21 million. While the $23 million reduced tax payments, the $21 million paid to Ameresco is not included in the income taxes paid table below. See Note 22 for more information about the BCE Sale.

The Company claimed a $33.4 million benefit for the Nuclear PTC on its 2024 tax return using a revenue requirement methodology to determine its gross receipts from nuclear sales. In the continued absence of IRS guidance regarding the definition of gross receipts from nuclear sales, management intends to utilize this same methodology to claim a 2025 credit of $39.6 million. These benefits include the five times multiplier for complying with IRS prevailing wage rules. However, due to the continued lack of IRS guidance, management believes that there remains uncertainty as to whether the IRS will ultimately agree with the Company's gross receipts methodology. As a result, the entire amount of the 2024 and 2025 benefits is recorded as uncertain tax positions and the Company continues to not recognize any income tax benefits related to the Nuclear PTC.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Net income associated with the Captive and Palo Verde sale leaseback VIEs is not subject to tax. As a result, there is no income tax expense associated with the VIEs recorded on the Pinnacle West Consolidated and APS Consolidated Statements of Income. See Note 12 for additional details related to Palo Verde sale leaseback VIEs.

The components of income tax expense are as follows (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	Year Ended December 31,			Year Ended December 31,		
	2025	2024	2023	2025	2024	2023
Current:						
Federal	$ 87,913	$ 137,342	$ 21,272	$ 94,207	$ 165,653	$ 26,405
State	10,892	2,392	2,854	31,424	26,054	1,027
Total current	98,805	139,734	24,126	125,631	191,707	27,432
Deferred:						
Federal	(11,073)	(53,228)	37,273	(2,902)	(69,075)	44,922
State	18,994	24,023	15,513	3,190	4,361	21,830
Total deferred	7,921	(29,205)	52,786	288	(64,714)	66,752
Income tax expense	106,726	110,529	76,912	125,919	126,993	94,184

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table compares Pinnacle West Consolidated pretax income at the 21% statutory federal income tax rate to income tax expense (dollars in thousands) and effective tax rates:

	Pinnacle West Consolidated					
	Year Ended December 31,					
	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
Income before income taxes (a)	$ 738,369		$ 736,559		$ 595,693	
Federal income tax expense at statutory rate	155,057	21.00 %	154,677	21.00 %	125,095	21.00 %
State income tax net of federal income tax benefit (b)	23,610	3.20 %	23,735	3.22 %	17,832	2.99 %
Changes in Valuation Allowance	—	— %	—	— %	—	— %
Nontaxable or Nondeductible Items						
Share based compensation	(4,062)	(0.55)%	(421)	(0.06)%	1,346	0.23 %
Palo Verde VIE noncontrolling interest (Note 12)	(3,173)	(0.43)%	(3,617)	(0.49)%	(3,617)	(0.61)%
Other Nontaxable or Nondeductible Items	5,896	0.80 %	3,667	0.50 %	2,405	0.40 %
Effect of changes in tax laws or rates enacted in the current period	—	— %	—	— %	—	— %
Tax Credits						
Solar or Wind Production Tax Credit	(14,698)	(1.99)%	(15,206)	(2.07)%	(8,441)	(1.42)%
Other Federal Income Tax Credits	(19)	— %	(242)	(0.03)%	(650)	(0.11)%
Investment credit amortization – deferral method	(12,625)	(1.71)%	(9,425)	(1.28)%	(9,495)	(1.59)%
Changes in Unrecognized Tax Benefits	1,523	0.21 %	(28)	— %	(1,961)	(0.33)%
Effects of Utility Ratemaking						
Excess deferred income taxes — Tax Cuts and Jobs Act	(36,558)	(4.95)%	(36,559)	(4.96)%	(36,558)	(6.14)%
Allowance for equity funds used during construction (Note 1)	(7,005)	(0.95)%	(2,545)	(0.35)%	(5,964)	(1.00)%
Other regulatory amortization	(2,758)	(0.38)%	(1,796)	(0.24)%	(1,828)	(0.31)%
Other Adjustments	1,538	0.20 %	(1,711)	(0.23)%	(1,252)	(0.20)%
Income tax expense	$ 106,726	14.45 %	$ 110,529	15.01 %	$ 76,912	12.91 %

(a) Income before income taxes is from continuing operations and is entirely domestic.
(b) The State of Arizona makes up the majority (greater than 50 percent) of the effect of the state and local income tax category.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table compares APS Consolidated pretax income at the 21% statutory federal income tax rate to income tax expense (dollars in thousands) and effective tax rates:

	APS Consolidated					
	Year Ended December 31,					
	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
Income before income taxes (a)	$ 808,346		$ 786,142		$ 658,745	
Federal income tax expense at statutory rate	169,753	21.00 %	165,090	21.00 %	138,337	21.00 %
State income tax net of federal income tax benefit (b)	27,345	3.38 %	26,824	3.41 %	21,453	3.26 %
Changes in Valuation Allowance	—	— %	—	— %	—	— %
Nontaxable or Nondeductible Items						
Share based compensation	(2,482)	(0.31)%	23	— %	997	0.15 %
Palo Verde VIE noncontrolling interest (Note 12)	(3,173)	(0.39)%	(3,617)	(0.46)%	(3,617)	(0.55)%
Other Nontaxable or Nondeductible Items	1,727	0.21 %	694	0.09 %	263	0.04 %
Effect of changes in tax laws or rates enacted in the current period	—	— %	—	— %	—	— %
Tax Credits						
Solar or Wind Production Tax Credit	(11,254)	(1.39)%	(12,110)	(1.54)%	(5,460)	(0.83)%
Other Federal Income Tax Credits	(19)	— %	(242)	(0.03)%	(650)	(0.10)%
Investment credit amortization – deferral method	(12,625)	(1.56)%	(9,425)	(1.20)%	(9,495)	(1.44)%
Changes in Unrecognized Tax Benefits	1,483	0.18 %	(107)	(0.01)%	(1,946)	(0.30)%
Effects of Utility Ratemaking						
Excess deferred income taxes — Tax Cuts and Jobs Act	(36,558)	(4.52)%	(36,559)	(4.65)%	(36,558)	(5.55)%
Allowance for equity funds used during construction (Note 1)	(7,005)	(0.87)%	(2,545)	(0.32)%	(5,964)	(0.91)%
Other regulatory amortization	(2,758)	(0.34)%	(1,796)	(0.23)%	(1,828)	(0.28)%
Other Adjustments	1,485	0.19 %	763	0.09 %	(1,348)	(0.19)%
Income tax expense	$ 125,919	15.58 %	$ 126,993	16.15 %	$ 94,184	14.30 %

(a) Income before income taxes is from continuing operations and is entirely domestic.
(b) The State of Arizona makes up the majority (greater than 50 percent) of the effect of the state and local income tax category.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the income taxes paid for Pinnacle West and APS on a retrospective basis (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	Year Ended December 31,			Year Ended December 31,		
	2025	2024	2023	2025	2024	2023
Federal	$ 20,894	$ 112,870	$ 8,609	$ 30,207	$ 156,112	$ 21,438
State	1,860	128	179	23,431	22,901	296
Total	$ 22,754	$ 112,998	$ 8,788	$ 53,638	$ 179,013	$ 21,734

State income taxes paid (net of refunds) exceed 5 percent of total income taxes paid (net of refunds) in the following jurisdictions (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	Year Ended December 31,			Year Ended December 31,		
	2025	2024	2023	2025	2024	2023
Arizona	$ 2,000	$ — (a)	$ — (a)	$ 23,423	$ 22,788	$ — (a)

(a) Jurisdiction below the threshold for the period presented.

The following is a tabular reconciliation of the total amounts of unrecognized tax benefits, excluding interest and penalties, at the beginning and end of the year that are included in accrued taxes and unrecognized tax benefits (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	2025	2024	2023	2025	2024	2023
Total unrecognized tax benefits, January 1	$ 44,349	$ 44,274	$ 43,097	$ 44,349	$ 44,274	$ 43,097
Additions for tax positions of the current year	81,286	1,271	1,473	81,286	1,271	1,473
Additions for tax positions of prior years	2,818	2,031	419	2,818	2,031	419
Reductions for tax positions of prior years for:						
Changes in judgment	(2,044)	(2,043)	661	(2,044)	(2,043)	661
Settlements with taxing authorities	—	—	—	—	—	—
Lapses of applicable statute of limitations	(970)	(1,184)	(1,376)	(970)	(1,184)	(1,376)
Total unrecognized tax benefits, December 31	$ 125,439	$ 44,349	$ 44,274	$ 125,439	$ 44,349	$ 44,274

Included in the balances of unrecognized tax benefits are the following tax positions that, if recognized, would decrease our effective tax rate (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	2025	2024	2023	2025	2024	2023
Tax positions, that if recognized, would decrease our effective tax rate	$ 103,785	$ 27,899	$ 28,762	$ 103,785	$ 27,899	$ 28,762

As of December 31, 2025, the tax year ended December 31, 2022 and all subsequent tax years remain subject to examination by the IRS. With a few exceptions, we are no longer subject to state income tax examinations by tax authorities for years before 2021.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

We reflect interest and penalties, if any, on unrecognized tax benefits in the Pinnacle West Consolidated and APS Consolidated Statements of Income as income tax expense. The amount of interest expense or benefit recognized related to unrecognized tax benefits are as follows (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	2025	2024	2023	2025	2024	2023
Unrecognized tax benefit interest expense recognized	$ 3,610	$ 2,743	$ 452	$ 3,610	$ 2,743	$ 452

Following are the total amounts of accrued liabilities for interest recognized related to unrecognized benefits that could reverse and decrease our effective tax rate to the extent matters are settled favorably (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	2025	2024	2023	2025	2024	2023
Unrecognized tax benefit interest accrued	$ 7,986	$ 4,376	$ 1,633	$ 7,986	$ 4,376	$ 1,633

As of December 31, 2025, we have recognized approximately $2.8 million of interest expense to be paid on the underpayment of income taxes for certain adjustments that we have filed, or will file, with the IRS.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The components of the net deferred income tax liability were as follows (dollars in thousands):

	Pinnacle West Consolidated		APS Consolidated	
	December 31,		December 31,	
	2025	2024	2025	2024
DEFERRED TAX ASSETS				
Risk management activities	$ 8,422	$ 14,539	$ 8,422	$ 14,539
Regulatory liabilities:				
Excess deferred income taxes — Tax Cuts and Jobs Act	259,000	271,004	259,000	271,004
Asset retirement obligation and removal costs	66,031	81,308	66,031	81,308
Unamortized investment tax credits	81,949	66,327	81,949	66,327
Other postretirement benefits	57,833	58,862	57,833	58,862
Other	50,611	47,671	50,611	47,671
Operating lease liabilities	923,774	400,771	923,479	400,442
Pension liabilities	46,613	39,070	43,422	36,100
Coal reclamation liabilities	39,450	42,391	39,450	42,391
Renewable energy incentives	11,908	14,571	11,908	14,571
Credit and loss carryforwards	—	7,682	—	—
Employee benefit liabilities	56,447	57,853	55,243	56,561
Other	49,098	44,412	49,098	44,412
Total deferred tax assets	1,651,136	1,146,461	1,646,446	1,134,188
DEFERRED TAX LIABILITIES				
Plant-related	(2,595,668)	(2,562,990)	(2,595,668)	(2,562,990)
Risk management activities	(2,072)	(4,089)	(2,072)	(4,089)
Pension and other postretirement assets	(97,557)	(83,401)	(96,988)	(82,925)
Other special use funds	(58,175)	(55,146)	(58,175)	(55,146)
Operating lease right-of-use assets	(923,774)	(400,771)	(923,479)	(400,443)
Regulatory assets:				
Allowance for equity funds used during construction	(50,402)	(47,694)	(50,402)	(47,694)
Deferred fuel and purchased power	(45,504)	(84,393)	(45,504)	(84,393)
Pension benefits	(178,736)	(185,641)	(178,736)	(185,641)
Ocotillo deferral	(24,703)	(28,372)	(24,703)	(28,372)
SCR deferral	(19,080)	(20,548)	(19,080)	(20,548)
Retired power plant costs	(13,157)	(16,904)	(13,157)	(16,904)
Other	(58,822)	(57,602)	(58,822)	(57,602)
Other	(54,418)	(43,383)	(7,425)	(7,378)
Total deferred tax liabilities	(4,122,068)	(3,590,934)	(4,074,211)	(3,554,125)
Deferred income taxes — net	$ (2,470,932)	$ (2,444,473)	$ (2,427,765)	$ (2,419,937)

As of December 31, 2025, Pinnacle West consolidated deferred tax assets for credit and loss carryforwards relate to federal credit carryforwards of $27.9 million. Pinnacle West consolidated credit and loss carryforwards amount above has been reduced by $27.9 million of unrecognized tax benefits.

As of December 31, 2025, APS consolidated deferred tax assets for credit and loss carryforwards relate to federal credit carryforwards of $12.4 million. APS consolidated credit and loss carryforwards amount above has been reduced by $12.4 million of unrecognized tax benefits.

6. Lines of Credit and Short-Term Borrowings

Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs, to refinance indebtedness, and for other general corporate purposes.

The table below presents the consolidated credit and term loan facilities and the amounts available and outstanding (dollars in thousands):

	December 31, 2025			December 31, 2024		
	Pinnacle West Consolidated	APS Consolidated	Total	Pinnacle West Consolidated	APS Consolidated	Total
Commitments under Revolving Credit and Term Loan Facilities	$ 375,000	$ 1,250,000	$ 1,625,000	$ 400,000	$ 1,650,000	$ 2,050,000
Outstanding short-term borrowings	(249,700)	(507,305)	(757,005)	(228,550)	(339,900)	(568,450)
Amount available under Revolving Credit and Term Loan Facilities	$ 125,300	$ 742,695	$ 867,995	$ 171,450	$ 1,310,100	$ 1,481,550
Weighted-Average Commitment Fees	0.225%	0.175%		0.225%	0.175%	

Pinnacle West

As of December 31, 2025, Pinnacle West had a $200 million revolving credit facility that matures on April 10, 2029. Pinnacle West has the option to increase the amount of the facility up to a total of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on Pinnacle West's senior unsecured debt credit ratings and the agreement includes a sustainability-linked pricing metric which provides for an interest rate reduction or increase, by meeting or missing, respectively, targets related to specific environmental and employee health and safety sustainability objectives. Under certain circumstances, the sustainability-linked pricing metric can be terminated for the final year of the credit facility. The facility is available to support Pinnacle West's general corporate purposes, including support for Pinnacle West's $200 million commercial paper program, for bank borrowings or for issuances of letters of credit. As of December 31, 2025, Pinnacle West had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under its credit facility, and $75 million of outstanding commercial paper borrowings. The weighted-average interest rate for the outstanding borrowings on December 31, 2025 was 3.81%.

On February 18, 2026, Pinnacle West's revolving credit facility was amended and extended with the following modifications, among others: (1) increasing the amount of the facility to $300 million and maintaining the option to expand it up to a total of $400 million, (2) extending the maturity date to February 18, 2031, with two 1-year extension options, (3) eliminating the sustainability-linked pricing metric, and (4) certain modifications to the definition and calculation of indebtedness to exclude (a) PPAs and energy storage leases that are recoverable through the PSA and (b) certain qualified securitization bonds. Pinnacle West's commercial paper program was also increased to $300 million.

Pinnacle West had an outstanding 364-day $200 million term loan facility that matured on December 4, 2025. Borrowings under the facility bore interest at SOFR plus 0.95% per annum. On December 20, 2024, Pinnacle West drew the full amount of $200 million and repaid it on December 4, 2025 using proceeds from a new unsecured 364-day $175 million term loan facility discussed below and commercial paper borrowings.

Pinnacle West has an outstanding 364-day $175 million term loan facility that matures on December 3, 2026. Borrowings under the facility bear interest at SOFR plus 0.80% per annum. On December 3, 2025, Pinnacle West drew the full amount of $175 million.

APS

As of December 31, 2025, APS had a $1.25 billion revolving credit facility, that matures on April 10, 2029. APS has the option to increase the amount of the facility to a total of $1.65 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings, and the agreement includes a sustainability-linked pricing metric which provides for an interest rate reduction or increase, by meeting or missing, respectively, targets related to specific environmental and employee health and safety sustainability objectives. Under certain circumstances, the sustainability-linked pricing metric can be terminated for the final year of the credit facility. The facility is available to support APS's general corporate purposes, including support for APS's $1 billion commercial paper program, for bank borrowings or for issuances of letters of credit. As of December 31, 2025, APS had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under the credit facility, and $507 million of outstanding commercial paper borrowings. The weighted-average interest rate for the outstanding borrowings on December 31, 2025 was 3.83%.

On February 18, 2026, APS's revolving credit facility was amended and extended with the following modifications, among others: (1) increasing the amount of the facility to $1.7 billion and maintaining the option to expand it up to a total of $2.1 billion, (2) extending the maturity date to February 18, 2031, with two 1-year extension options, (3) eliminating the sustainability-linked pricing metric, and (4) certain modifications to the definition and calculation of indebtedness to exclude (a) PPAs and energy storage leases that are recoverable through the PSA and (b) certain qualified securitization bonds. APS's commercial paper program was also increased to $1.5 billion.

On December 5, 2024, APS entered into a $400 million 364-Day Term Loan Agreement that matured on December 4, 2025. Borrowings under the facility bore interest at SOFR plus 0.90% per annum. APS drew the full amount of $400 million on April 29, 2025 and repaid it on August 15, 2025 using proceeds from unsecured senior notes issuances. See Note 7.

See "Financial Assurances" in Note 14 for a discussion of other outstanding letters of credit.

Debt Provisions

On December 17, 2024, the ACC issued a financing order that reaffirmed APS's short-term debt authorization equal to the sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power) and increased the long-term debt limit to $9.5 billion and made certain changes to permitted annual equity infusions into APS. See Note 7 for additional long-term debt provisions.

7. Long-Term Debt and Liquidity Matters

All of Pinnacle West's and APS's debt is unsecured. The following table presents the components of long-term debt on the Consolidated Balance Sheets outstanding (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31, 2025	December 31, 2024
APS				
Pollution control bonds:				
Variable	2029	(b)	$ 163,975	$ 163,975
Total pollution control bonds			163,975	163,975
Senior unsecured notes	2026-2055	2.20%-6.88%	8,030,000	7,380,000
Unamortized discount			(16,796)	(14,252)
Unamortized premium			17,144	9,955
Unamortized debt issuance cost			(54,383)	(48,800)
Total APS long-term debt			8,139,940	7,490,878
Less current maturities			250,000	300,000
Total APS long-term debt less current maturities			7,889,940	7,190,878
Pinnacle West				
Senior unsecured notes	2027-2030	4.75%-5.15%	1,325,000	1,025,000
Floating rate note	2026	(c)	350,000	350,000
Unamortized discount			(681)	(5)
Unamortized debt issuance cost			(8,583)	(7,225)
Total Pinnacle West long-term debt			1,665,736	1,367,770
Less current maturities			350,000	500,000
Total Pinnacle West long-term debt less current maturities			1,315,736	867,770
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$ 9,205,676	$ 8,058,648

(a) This schedule does not reflect the timing of redemptions that may occur prior to scheduled maturity.
(b) The weighted-average interest rate for the variable rate pollution control bonds was 3.52% at December 31, 2025, and 4.01% at December 31, 2024.
(c) The weighted-average interest rate was 5.10% at December 31, 2025, and was 5.88% at December 31, 2024. See additional details below.

The following table shows principal payments due on Pinnacle West's and APS's total long-term debt (dollars in thousands):

Year	Pinnacle West Consolidated	APS Consolidated
2026	$ 600,000	$ 250,000
2027	825,000	300,000
2028	400,000	—
2029	568,975	568,975
2030	400,000	—
Thereafter	7,075,000	7,075,000
Total	$ 9,868,975	$ 8,193,975

Debt Fair Value

Our long-term debt fair value estimates are classified within Level 2 of the fair value hierarchy. The following table represents the estimated fair value of our long-term debt, including current maturities (dollars in thousands):

	As of December 31, 2025		As of December 31, 2024	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 1,665,736	$ 1,731,388	$ 1,367,770	$ 1,393,744
APS	8,139,940	7,433,142	7,490,878	6,525,248
Total	$ 9,805,676	$ 9,164,530	$ 8,858,648	$ 7,918,992

Debt and Equity Issuances

Pinnacle West

On February 28, 2024, Pinnacle West entered into equity forward sale agreements (the "February 2024 Forward Sale Agreements"), which may be settled with Pinnacle West common stock or cash. Pinnacle West also has an ATM Program under which it may offer and sell common stock and enter into forward sale agreements from time to time, subject to market conditions and other factors.

In August 2025, Pinnacle West amended the February 2024 Forward Sale Agreements with Wells Fargo Bank, National Association to extend the maturity date to December 31, 2026. In September 2025, Pinnacle West partially settled the February 2024 Forward Sale Agreements by issuing 243,186 shares of common stock and receiving net proceeds of $15 million. In December 2025, Pinnacle West partially settled the February 2024 Forward Sale Agreements by issuing 1,193,950 shares of common stock and receiving net proceeds of $75 million. The proceeds from both partial settlements were recorded in equity and were used for general corporate purposes. See Note 16 for more information on the February 2024 Forward Sale Agreements and the ATM Program.

On May 15, 2025, Pinnacle West issued $400 million of 4.90% senior unsecured notes that mature May 15, 2028 and $400 million of 5.15% senior unsecured notes that mature May 15, 2030. The net proceeds from the issuances were used to repay $500 million of 1.3% senior unsecured notes that were maturing June 15, 2025 and for general corporate purposes.

Pinnacle West also has $525 million of 4.75% Convertible Senior Notes due 2027 ("Convertible Notes") outstanding, which are senior unsecured obligations of Pinnacle West and will mature on June 15, 2027. See Note 16 for more information.

APS

On May 15, 2025, Pinnacle West contributed $300 million into APS in the form of an equity infusion. APS used this contribution to repay the $300 million of 3.15% senior notes that matured on the same date.

On December 18, 2025, Pinnacle West contributed $75 million into APS in the form of an equity infusion. APS used this contribution for general corporate purposes.

On August 15, 2025, APS issued $700 million of 5.90% senior unsecured notes that mature August 15, 2055 and reopened its 5.70% senior unsecured notes that mature August 15, 2034, issuing an additional $250 million of such notes. The net proceeds from the issuances were used to repay the $400 million 364-day Term Loan and for general corporate purposes. See Note 6.

See "Lines of Credit and Short-Term Borrowings" in Note 6 for discussion of Pinnacle West's and APS's revolving credit facilities. See Notes 6 and 14 for discussion of APS's separate outstanding letters of credit.

Debt Provisions

Pinnacle West's and APS's debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with these covenants. For both Pinnacle West and APS, this covenant requires that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At December 31, 2025, the ratio was approximately 60% for Pinnacle West and 50% for APS. Failure to comply with such covenant levels would result in an event of default, which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could cross-default other debt. See further discussion of "cross-default" provisions below.

Neither Pinnacle West's nor APS's financing agreements contain "rating triggers" that would result in an acceleration of the required interest and principal payments in the event of a rating downgrade. However, our bank credit agreements contain a pricing grid in which the interest rates we pay for borrowings thereunder are determined by our current credit ratings.

All of Pinnacle West's and APS's credit agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment if Pinnacle West or APS were to default under certain other material agreements. Pinnacle West and APS do not have a material adverse change covenant for credit facility borrowings.

Although provisions in APS's articles of incorporation and ACC financing orders establish maximum amounts of preferred stock and debt that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements.

The ACC has authorized a limit on yearly equity infusions into APS equal to 2.5% of APS's total assets each calendar year on a three-year rolling average basis, subject to APS's equity ratio remaining below the most recently approved rate case capital structure plus 50 basis points. See Note 6 for additional short-term debt provisions.

8. Regulatory Matters

ACC General Retail Rate Cases

2025 Rate Case

On June 13, 2025, APS filed an application with the ACC (the "2025 Rate Case") seeking a net base rate increase of $579.5 million, which represents a 13.99% net increase. The requested net increase addresses a total base revenue deficiency of $662.4 million, offset by proposed adjustor transfers of cost recovery to base rates.

The 2025 Rate Case application includes the following proposals:

- a test year comprised of the 12-month period ended on December 31, 2024, including certain pro forma adjustments;
- 12 months of post-test year plant placed into service from January 1, 2025 through December 31, 2025;
- an original cost rate base of $12.5 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	47.65 %	4.26 %
Common stock equity	52.35 %	10.70 %
Weighted-average cost of capital		7.63 %

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- a rate of $0.043881 per kWh for the portion of APS's base rates attributable to fuel and purchased power costs;
- adjustments to rate designs, including direct assignment of costs, to reduce cross-subsidization by certain customer classes;
- modification of cost allocation methodologies based on customer growth to ensure customers causing new production costs are covering those costs through rates, along with corresponding changes to adjustor mechanisms, such as for fuel and purchased power;
- implementation of a FRAM to assist with reducing regulatory lag and allow for rate gradualism;
- elimination of the LFCR following the first annual adjustment pursuant to the FRAM; and
- modification to the SRB due to the FRAM proposal.

APS requested that the increase become effective in the second half of 2026. The hearing for this rate case is currently scheduled to begin in May 2026. APS cannot predict the outcome of its request nor when the 2025 Rate Case will be decided by the ACC.

2022 Rate Case

On October 28, 2022, APS filed an application with the ACC (the "2022 Rate Case") for an increase in retail base rates, and on January 25, 2024, an Administrative Law Judge issued a Recommended Opinion and Order ("ROO"), as corrected on February 6, 2024 (the "2022 Rate Case ROO").

On February 22, 2024, the ACC approved the 2022 Rate Case ROO with certain amendments that resulted in, among other things, (i) an approximately $491.7 million increase in the annual base revenue requirement, (ii) a 9.55% return on equity, (iii) a 0.25% return on the increment of fair value rate base greater than original cost, (iv) an effective fair value rate of return of 4.39%, (v) a return set at the Company's weighted average cost of capital on the net prepaid pension asset and net other post-employment benefit liability in rate base, (vi) an adjustment to generation maintenance and outage expense to reflect a more reasonable level of test year costs, (vii) approval of the SRB mechanism with modifications to customer notifications, procedural timelines and the inclusion of any qualifying technology and fuel source bid received through an ASRFP, and (viii) recovery of all DSM costs through the DSMAC rather than through base rates.

The ACC issued the final order for the 2022 Rate Case on March 5, 2024, with the new rates becoming effective for all service rendered on or after March 8, 2024.

Six intervenors and the Attorney General of Arizona requested rehearing on various issues included in the ACC's decision, such as the GAC for solar customers, the SRB, and Coal Community Transition funding. On April 15, 2024, the ACC granted, in part, the rehearing applications of the Attorney General, AriSEIA, SEIA, and Vote Solar specifically to review whether the GAC rate is just and reasonable, including whether it should be higher or lower, whether the GAC rate constitutes a discriminatory fee to solar customers, and whether omission of a GAC charge is discriminatory to non-solar customers. All other applications for rehearing were denied. A limited rehearing was held October 28 through November 1, 2024. Following the limited rehearing, an Administrative Law Judge issued a ROO (the "Limited Rehearing ROO") on December 3, 2024. The Limited Rehearing ROO recommended affirming the GAC as just and reasonable and that the GAC is not discriminatory to solar customers and the absence of a GAC is not discriminatory to non-solar customers. On December 17, 2024, the ACC approved the Limited Rehearing ROO with an amendment that requires APS in its next rate case to propose a revenue allocation based on a site-load cost of service study in order to bring further parity in revenue collection between solar and non-solar customers. SEIA, AriSEIA, Vote Solar, the Arizona Attorney General, and two individual customers have filed requests for rehearing of the ACC's December 17, 2024 decision on the rehearing. The ACC has taken no action on these requests. In addition, each of these parties have subsequently filed an appeal to the Arizona Court of Appeals seeking review of the ACC's decisions regarding the GAC and on rehearing. APS cannot predict the outcome of these proceedings.

Regulatory Lag Docket

On January 5, 2023, the ACC opened a new docket to explore the possibility of modifications to the ACC's historical test year rules. The ACC requested comments and held two workshops exploring ways to reduce regulatory lag, including alternative ratemaking structures such as future test years, hybrid test years, and formula rates. On December 3, 2024, the ACC approved a policy statement regarding formula rate plans. The policy statement provides regulated utilities with the opportunity to propose formula rate plans in future rate cases. On March 28, 2025, RUCO, ALCG, and an individual customer filed a lawsuit challenging the ACC's authority to issue the formula rate policy statement outside of Arizona's formula rulemaking process. On June 13, 2025, the lawsuit challenging the ACC's formula rate policy was dismissed by the Superior Court of Maricopa County. Following the dismissal, the plaintiffs filed an appeal with the Arizona Court of Appeals as well as a Petition for Special Action with the Arizona Supreme Court. The Supreme Court declined to exercise jurisdiction on the Petition for Special Action. The plaintiffs also filed a Petition for Special Action with the Arizona Court of Appeals, which has accepted jurisdiction to determine whether the case should be remanded back to the Superior Court for expedited consideration of the merits. On November 21, 2025, the Arizona Court of Appeals ruled that the issue should be remanded back to the Superior Court to determine whether the ACC's formula rate policy must go through a formal rulemaking process. In response, APS, the ACC, and several other Arizona utility companies filed petitions for review of the Court of Appeals decision with the Arizona Supreme Court, which is pending at this time. APS cannot predict the outcome of this matter.

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs outside of a general retail rate case through the following recovery mechanisms. See "2022 Rate Case" above for modifications of adjustment mechanisms in the 2022 Rate Case and "2025 Rate Case" above for proposed modifications to adjustment mechanisms in the 2025 Rate Case.

Renewable Energy Standard

Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including, for example, solar, wind, biomass, biogas and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to recover the approved amounts for use on renewable energy projects. Each year, APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year's RES budget. As discussed below in "Energy Modernization Plan," on August 14, 2025, the ACC voted to send a full repeal of the RES rules to the Secretary of State for publication. APS cannot predict the outcome of this matter, or the impact it may have on the RES surcharge.

On July 1, 2022, APS filed its 2023 RES Implementation Plan and proposed a budget of approximately $86.2 million, excluding any funding offsets. This budget contained funding for programs to comply with ACC-approved initiatives, including the 2019 Rate Case decision. APS's budget proposal supported existing approved projects and commitments and requested a waiver of the RES residential and non-residential distributed energy requirements for 2023. On November 10, 2022, the ACC approved the 2023 RES Implementation Plan, including APS's requested waiver of the distributed energy requirement for 2023.

On June 30, 2023, APS filed its 2024 RES Implementation Plan and proposed a budget of approximately $95.1 million, excluding any funding offsets. On July 1, 2024, APS filed its 2025 RES Implementation Plan and proposed a budget of approximately $92.7 million. On July 1, 2025, APS filed its 2026 RES Implementation Plan and proposed a budget of approximately $110.1 million, excluding any funding offsets. APS's budget proposal supports existing approved projects and commitments and requests a waiver of the RES renewable energy credit requirements to demonstrate compliance with the Annual Renewable Energy Requirement for 2025. The proposed plan also notifies the ACC that continued evaluation and approval of the pending 2024 and 2025 RES Implementation Plans is no longer necessary. On February 4, 2026, the ACC approved APS's 2026 RES Implementation Plan.

On April 22, 2025, the ACC approved APS's request to refund uncommitted DSMAC and RES surcharge funds of approximately $9 million and $43 million, respectively, with final amounts subject to adjustment dependent upon billed usage. Refunds were issued during July and August of 2025 totaling $7.6 million for DSMAC and $44.2 million for RES.

APS has a Green Power Partners Program that allows customers to pay a specified price to receive a contracted amount of green power in addition to their normal rate in order to support those customers in meeting their individual sustainability goals. On June 28, 2024, APS filed an application for approval of modifications to the Green Power Partners Program and requested a renewable energy credit waiver. On February 4, 2026, the ACC approved APS's proposed changes to the Green Power Partners Program, including modifications to pricing structures for participating customers.

Demand Side Management Adjustor Charge

The ACC Electric Energy Efficiency Standards require APS to submit a DSM Implementation Plan at least every odd year for review and approval by the ACC. Verified energy savings from APS's resource savings projects can be counted toward compliance with the Electric Energy Efficiency Standards; however, APS is not allowed to count savings from systems savings projects toward determination of the achievement of performance incentives, nor may APS include savings from these system savings projects in the calculation of its LFCR mechanism. See below for discussion of the LFCR.

On November 30, 2022 and May 31 2023, APS filed its 2023 DSM Implementation Plan, which requested a budget of $88 million, and an amended 2023 DSM Implementation Plan, respectively. Subsequent to filing the amended 2023 DSM Implementation Plan and prior to the ACC approving it, on November 30, 2023, APS filed its 2024 DSM Implementation Plan. The 2024 DSM Implementation Plan requested a total budget of $91.5 million and incorporated all elements of the amended 2023 DSM Implementation Plan as well as the 2024 Transportation Electrification Implementation Plan. On April 26, 2024 and June 20, 2025, APS filed amendments to the 2024 DSM Implementation Plan. The Second Amended 2024 DSM Implementation Plan, compared to the initially filed plan, supported an updated budget of $90.9 million, which reflected (i) removal of incentive funds for the Level 2 Smart Charger rebate within the EV Charging Demand Management Pilot, (ii) exclusion of the proposed tranches two and three of the Residential Battery Pilot, and inclusion of the newly approved Bring-Your-Own-Device Battery ("BYOD") Pilot described below, and (iii) an update on the performance incentive calculation. On May 16, 2025, APS filed a request with the ACC to extend the deadline to file its 2026 DSM Implementation Plan until 120 days after the ACC acts on its Second Amended 2024 DSM Implementation Plan. On July 9, 2025, the ACC approved APS's extension request. On December 3, 2025, the ACC voted to reduce the budget of the DSM program to $40 million and discontinue several programs and customer rebates while promoting the expansion of Virtual Power Plant programs. APS will file a compliance plan with the ACC within 120 days of the decision.

On August 30, 2024, APS filed an application for a new BYOD Battery Pilot Plan of Administration with the ACC as required by Decision No. 79293. This plan would allow APS to work with residential customers to enable APS to dispatch participating batteries and use them to provide demand response capacity to the grid. On March 20, 2025, the ACC approved the BYOD Plan of Administration.

As discussed above under "RES," APS refunded uncommitted DSMAC funds during July and August 2025 totaling $7.6 million for DSMAC.

As discussed below in "Energy Modernization Plan," on September 17, 2025, the ACC voted to send a full repeal of the EES rules to the Secretary of State for publication. APS cannot predict the outcome of this matter, or the impact it may have on the DSMAC.

Power Supply Adjustor Mechanism and Balance

The PSA provides for the adjustment of retail rates to reflect variations primarily in retail fuel and purchased power costs. The PSA is subject to specified parameters and procedures, including the following:

- APS records deferrals for recovery or refund to the extent actual retail fuel and purchased power costs vary from Base Fuel Rate;
- an adjustment to the PSA rate is made annually each February 1 (unless otherwise approved by the ACC) and goes into effect automatically unless suspended by the ACC;
- the PSA uses a forward-looking estimate of fuel and purchased power costs to set the annual PSA rate, which is reconciled to actual costs experienced for each PSA Year (February 1 through January 31) (see the following bullet point);
- the PSA rate includes (a) a "forward component," under which APS recovers or refunds differences between expected fuel and purchased power costs for the upcoming calendar year and those embedded in the Base Fuel Rate; (b) a "historical component," under which differences between actual fuel and purchased power costs and those recovered or refunded through the combination of the Base Fuel Rate and the forward component are recovered during the next PSA Year; and (c) a "transition component," under which APS may seek mid-year PSA changes due to large variances between actual fuel and purchased power costs and the combination of the Base Fuel Rate and the forward component; and
- the PSA rate may not be increased or decreased more than $0.006 per kWh in a year without permission of the ACC.

The following table shows the changes in the deferred fuel and purchased power regulatory asset (dollars in thousands):

	Year Ended December 31,	
	2025	**2024**
Balance at beginning of period	$ 287,597	$ 463,195
Deferred fuel and purchased power costs	324,482	250,288
Amounts charged to customers	(463,011)	(425,886)
Balance at end of period	$ 149,068	$ 287,597

In Decision No. 79293 in the 2022 Rate Case, the ACC approved a permanent increase in the annual PSA adjustor rate cap from $0.004 per kWh to $0.006 per kWh and a requirement that APS report to the ACC for possible action when the overall PSA balance reaches $100 million. As part of the 2022 Rate Case decision, the ACC also approved an overall PSA rate of $0.011977 per kWh, which consisted of a forward component of $(0.012624) per kWh, a historical component of $0.013071 per kWh, and a transition component of $0.011530 per kWh. The overall PSA rate was reduced to offset an increase in base fuel prices. The rate became effective on March 8, 2024.

On November 27, 2024, APS filed its PSA rate for the PSA year beginning February 1, 2025. The overall PSA rate of $0.013977 per kWh consists of a forward component of $(0.000281) per kWh, a historical component of $0.008728 per kWh, and a transition component of $0.005530 per kWh. This overall PSA rate is an increase of $0.002 per kWh over the prior overall rate approved in the 2022 Rate Case decision, and it is below the annual PSA rate increase cap of $0.006 per kWh. On February 5, 2025, the ACC voted to approve this request, with a rate effective date of the first billing cycle in March 2025.

On November 26, 2025, APS filed its PSA rate for the PSA year beginning February 1, 2026. The overall PSA rate of $0.016977 per kWh consists of a forward component of $0.012457 per kWh, a historical component of $0.00452 per kWh, and a transition component of $0.0 per kWh. This overall PSA rate is an increase of $0.003 per kWh over the prior approved rate, and it is below the annual PSA rate increase cap of $0.006 per kWh. The rate became effective the first billing cycle of February 2026.

Environmental Improvement Surcharge

Following the ACC approval to eliminate the Environmental Improvement Surcharge on March 5, 2024, the surcharge is no longer in effect, and any remaining amounts are being collected through base rates. The Environmental Improvement Surcharge permitted APS to recover the capital carrying costs (rate of return, depreciation and taxes) plus incremental operations and maintenance expenses associated with environmental improvements made outside of a test year to comply with environmental standards set by federal, state, tribal, or local laws and regulations.

Transmission Rates, Transmission Cost Adjustor, and Other Transmission Matters

APS's retail transmission charges' formula rate is updated each year effective June 1 on the basis of APS's actual cost of service, as disclosed in APS's FERC Form 1 report for the previous fiscal year. Items to be updated include actual capital expenditures made as compared with previous projections, transmission revenue credits and other items. APS reviews the proposed formula rate filing amounts with the ACC Staff. Any items or adjustments which are not agreed to by APS and the ACC Staff can remain in dispute until settled or litigated with FERC. Settlement or litigated resolution of disputed issues could require an extended period of time and could have a significant effect on the Retail Transmission Charges because any adjustment, though applied prospectively, may be calculated to account for previously over- or under-collected amounts. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected.

Effective June 1, 2023, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $34.7 million for the 12-month period beginning June 1, 2023, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by approximately $20.7 million and retail customer rates would have increased by approximately $14 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC-approved balancing account, the retail revenue requirement decreased by $10 million, resulting in reductions to the residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2023.

Effective June 1, 2024, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $27.4 million for the 12-month period beginning June 1, 2024 in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by approximately $16.6 million and retail customer rates would have increased by approximately $10.8 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC-approved balancing account, the retail revenue requirement increased by $8.8 million, resulting in an increase to residential rates and commercial rates over 3 MW and a decrease to commercial rates less than or equal to 3 MW. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2024.

Effective June 1, 2025, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $119.0 million for the 12-month period beginning June 1, 2025, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by approximately $4.6 million and retail customer rates would have increased by approximately $114.4 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC-approved balancing account, the retail revenue requirement increased by $88.3 million, resulting in increases to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2025.

Lost Fixed Cost Recovery Mechanism

The LFCR mechanism permits APS to recover on an after-the-fact basis a portion of its fixed costs that would otherwise have been collected by APS in the kWh sales lost due to APS energy efficiency programs and to DG such as rooftop solar arrays. The adjustment to the LFCR has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWhs lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. DG sales losses are determined from the metered output from the DG units.

On July 31, 2023, APS filed its 2023 annual LFCR adjustment, requesting that the annual LFCR recovery amount be increased to $68.7 million (a $9.6 million increase from previous levels). As a result of Decision No. 79293 in the 2022 Rate Case, APS transferred $27.1 million from the LFCR to base rates.

On March 8, 2024, APS filed conforming LFCR schedules to incorporate changes required as a result of Decision No. 79293 in the 2022 Rate Case. On April 9, 2024, the ACC approved the 2023 annual LFCR adjustment, with new rates effective in the first billing cycle of May 2024.

On June 5, 2024, APS filed a revised LFCR Plan of Administration in accordance with Decision No. 79293. The ACC approved the revised Plan of Administration on October 8, 2024.

On July 31, 2024, APS filed its 2024 annual LFCR adjustment, requesting that effective November 1, 2024, the annual LFCR recovery amount be increased to $49.6 million (an $8 million increase from previous levels). On December 3, 2024, the ACC approved the 2024 annual LFCR adjustment, with new rates effective in the first billing cycle of January 2025.

On July 31, 2025, APS filed its 2025 annual LFCR adjustment, requesting that effective November 1, 2025, the annual LFCR recovery amount be increased to $60.1 million (a $10.5 million increase from previous levels). On November 21, 2025, the ACC approved the 2025 annual LFCR adjustment, with new rates effective in the first billing cycle of December 2025.

Tax Expense Adjustor Mechanism

The TEAM helps address potential federal income tax reform and enables the pass-through of certain income tax effects to customers. The TEAM expressly applies to APS's retail rates with the exception of a small subset of customers taking service under specially-approved tariffs. Currently, the TEAM is set to a zero rate as per ACC Decision No. 79293.

Court Resolution Surcharge

Following an appeal of the 2019 Rate Case decision, the ACC approved a Court Resolution Surcharge ("CRS") mechanism that permits APS to recover certain costs associated with investments and expenses for APS's purchase and installation of selective catalytic reduction ("SCR") technology for Four Corners Units 4 and 5 and a change in APS's allowable return on equity as required by the Arizona Court of Appeals and approved by the ACC in Decision No. 78979. The CRS went into effect on July 1, 2023, at a rate of $0.00175 per kWh. The rate is designed to recover $59.6 million in revenue lost by APS between December 2021 and June 20, 2023, and the prospective recovery of ongoing costs related to the SCR investments and expense and the allowable return on equity difference in current base rates. The portion of the CRS representing the recovery of the $59.6 million of lost revenue between December 2021 and June 20, 2023, $43.2 million of which has been collected as of December 31, 2025, will cease upon full collection of the lost revenue. Additionally, the CRS tariff was updated to remove the return on equity component and account for SCR-related depreciation and deferral adjustments approved in Decision No. 79293 in the 2022 Rate Case.

Solar Export Price

Payments by APS for energy exported to the grid from residential DG solar facilities are determined using a Resource Comparison Proxy ("RCP") methodology as determined in the ACC's generic Value and Cost of DG docket. The RCP is a method that is based on the most recent five-year rolling average price that APS incurs for utility-scale solar photovoltaic projects. The price established by this RCP method is updated annually (between general retail rate cases) but cannot be decreased by more than 10% per year.

On May 1, 2023, APS filed an application for revisions to the RCP. This application would decrease the RCP price to $0.07619 per kWh, reflecting a 10% annual reduction, to become effective September 1, 2023. On August 25, 2023, the ACC approved the RCP as filed.

On May 1, 2024, APS filed an application for revisions to the RCP. This application would decrease the RCP price to $0.06857 per kWh, reflecting a 10% annual reduction, to become effective September 1, 2024. On August 13, 2024, the ACC approved the RCP as filed.

On May 1, 2025, APS filed an application for revisions to the RCP. This application would decrease the RCP price to $0.06171 per kWh, reflecting a 10% annual reduction, to become effective September 1, 2025. On August 14, 2025, the ACC approved the RCP as filed.

On October 11, 2023, the ACC voted to open a new general docket to hold a hearing to explore potential future changes to the 10% annual reduction cap in the solar export rate paid by utilities to distributed solar customers for exports to the grid and the 10-year rate lock period for those customers that were approved in the ACC's Value and Cost of DG Docket. Following various conferences, the ACC Staff filed a report finding that the RCP is working as intended and recommending no changes at this time along with closure of the docket. On October 6, 2025, the ACC administratively closed the general docket, and APS expects no additional action in this matter.

Energy Modernization Plan

On May 26, 2023, the ACC opened a new docket to review the Arizona Administrative Code related to Resource Planning, the RES, and EES. On January 9, 2024, the ACC approved the opening of new dockets to begin rulemaking process for EES and RES. It was also ordered that an existing rulemaking docket would be utilized to review proposed updates to the ASRFP and Resource Planning Rules. During an ACC Open Meeting on February 6, 2024, the ACC approved motions to direct ACC Staff to include recommendations to repeal the current EES and RES rules during the rulemaking process. On August 21, 2024, the ACC Staff filed separate reports for each set of rules, including its recommendations to repeal the EES and RES rules along with required preliminary economic, small business, and consumer impact statements. APS and other interested parties have filed comments about the ACC Staff reports.

The ACC voted to send to the Secretary of State full repeals of the RES and EES rules on August 14, 2025 and September 17, 2025, respectively, for publication and to begin the public rulemaking process. APS cannot predict the outcome of these matters, or the impacts they may have on the RES or DSM surcharges discussed above.

Integrated Resource Plan

ACC rules require utilities to develop triennial 15-year IRPs which describe how the utility plans to serve customer load in the plan time frame. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. In February 2022, the ACC acknowledged APS's 2020 IRP filed on June 26, 2020. The ACC also approved certain amendments to the IRP process, including setting an EES of 1.3% of retail sales annually (averaged over a three-year period) and a demand-side resource capacity of 35% of 2020 peak demand by January 1, 2030.

On May 1, 2023, APS, Tucson Electric Power Company, and UNS Electric, Inc. filed a joint request for an extension to file the IRPs from August 1, 2023 to November 1, 2023. On June 21, 2023, the ACC granted the extension. As a result, APS filed its 2023 IRP on November 1, 2023. On January 31, 2024, stakeholders filed comments regarding the IRP, and APS filed its response to stakeholder comments on May 31, 2024. On July 31, 2024, the ACC held an IRP workshop where utilities and stakeholders presented on the 2023 IRPs. On October 8, 2024, the ACC acknowledged APS's 2023 IRP and approved certain amendments to the IRP process, including requirements for APS to demonstrate system resource adequacy as well as analysis of impacts from western market participation and planned resource requirements in the next IRP, which is due to be filed on August 3, 2026.

Residential Electric Utility Customer Service Disconnections

In accordance with the ACC's service disconnection rules, APS uses a calendar-based method to suspend the disconnection of customers for nonpayment from June 1 through October 15 each year ("Annual Disconnection Moratorium"). Since the Annual Disconnection Moratorium began, APS has experienced an increase in bad debt expense and the related write-offs of delinquent customer accounts. Pursuant to an ACC order, customers with past due balances of $75 or greater as of approximately one month prior to the end of the Annual Disconnection Moratorium are automatically placed on six-month payment arrangements.

Cholla Power Plant

On September 11, 2014, APS announced that it would close Unit 2 of Cholla and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s if EPA approved a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the unit. APS closed Unit 2 on October 1, 2015. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect on April 26, 2017. In December 2019, PacifiCorp notified APS that it planned to retire Cholla Unit 4 by the end of 2020, and the unit ceased operation in December 2020. APS was required to cease burning coal at its remaining Cholla units by April 2025.

On August 14, 2024, APS filed a request with the ACC for a deferral order associated with unrecovered book value and decommissioning and site remediation costs of Cholla Units 1 and 3 related to the cessation of coal-burning operations at Cholla in April 2025. This order would authorize APS to defer for future recovery in rates the expenses necessary to cease operating coal-fired power plant infrastructure at Cholla, including legally required site environmental remediation, CCR corrective actions, the closure of CCR management facilities, and any unrecovered plant investment and operating costs incurred through and after April 2025. On July 8, 2025, APS withdrew its deferral application, requesting that the costs that would have been covered in the deferral order request instead be addressed in the 2025 Rate Case. APS cannot predict the outcome of this matter.

APS ceased coal-burning operations at Cholla in March 2025 and formally retired Cholla Units 1 and 3 on April 30, 2025. Upon the cessation of coal-fired operations, APS had approximately $81 million of remaining net-book value associated with Units 1 and 3 plant assets. APS is currently recovering in rates a return on the net-book value of its interest in Cholla and associated depreciation costs. In the 2025 Rate Case, APS has requested recovery in rates of the ongoing environmental remediation and CCR closure costs associated with Cholla and any remaining unrecovered plant costs. The 2025 Rate Case also includes a request for an ongoing deferral order relating to anticipated increased environmental remediation costs relating to Cholla that may be incurred after the 2025 Rate Case proceeding.

For Cholla Unit 2, APS has been allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs, totaling $23.6 million as of December 31, 2025, in addition to a return on its investment. In the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to regulatory assets. In accordance with the 2019 Rate Case decision, the regulatory asset is being amortized through 2033.

Navajo Plant

The Navajo Plant ceased operations in November 2019. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017 that allows for decommissioning activities to begin after the plant ceased operations. In accordance with GAAP, in the second quarter of 2017, APS's remaining net book value of its interest in the Navajo Plant was reclassified from property, plant and equipment to regulatory assets.

APS has been recovering a return on and of the net book value of its interest in the Navajo plant in base rates over its previously estimated life through 2026. Pursuant to the 2019 Rate Case decision described above, APS will be allowed continued recovery of the book value of its remaining investment in the Navajo plant, $23.8 million as of December 31, 2025, in addition to a return on the net book value, with the exception of 15% of the annual amortization expense in rates. In addition, APS will be allowed recovery of other costs related to retirement and closure, including the Navajo coal reclamation regulatory asset, $2.5 million as of December 31, 2025. The disallowed recovery of 15% of the annual amortization does not have a material impact on APS financial statements.

Fire Mitigation

On August 14, 2024, APS filed a request with the ACC for a deferral order that would authorize APS to defer, for future recovery in rates, operations and maintenance expenses associated with wildfire management, including increased insurance costs. On June 18, 2025, the ACC denied APS's request and recommended that wildfire related expenses be recovered in APS's 2025 Rate Case.

On May 12, 2025, Arizona Governor Hobbs signed into law a bill that requires Arizona electric utilities to develop and seek approval for wildfire mitigation plans and defines the standard of care with respect to wildfire-related claims by reference to such plans.

Regulatory Assets and Liabilities

The detail of regulatory assets is as follows (dollars in thousands):

	Amortization Through	December 31, 2025	December 31, 2024
Pension	(a)	$ 723,042	$ 750,976
Income taxes — AFUDC equity	2054	203,890	192,936
Palo Verde sale leaseback noncontrolling interests' acquisition (b)	N/A	151,506	—
Deferred fuel and purchased power (c) (d)	2026	149,068	287,597
Ocotillo deferral	2034	99,931	114,775
Lease incentive (Note 20)	2045	90,005	70,541
SCR deferral (c)	2038	77,186	83,123
Retired power plant costs	2031	56,809	68,380
Income taxes — investment tax credit basis adjustment (Note 5)	2056	42,459	34,834
Deferred compensation	2036	32,204	33,108
Deferred fuel and purchased power — mark-to-market (Note 13)	2026	29,330	42,275
FERC transmission true up	2027	21,471	35,159
DSM (c)	2025	15,706	—
Deferred property taxes	2027	15,349	23,918
Palo Verde VIEs (Note 12)	2046	8,582	20,611
Mead-Phoenix transmission line — contributions in aid of construction	2050	8,052	8,384
PSA - interest	2026	5,679	11,525
Loss on reacquired debt	2038	5,653	6,682
TEAM (c)	2031	3,879	4,534
Active union medical trust	(e)	3,696	9,673
Navajo coal reclamation	2026	2,516	7,905
Other	Various	3,353	3,522
Total regulatory assets (f)		$ 1,749,366	$ 1,810,458
Less: current regulatory assets		$ 286,009	$ 420,969
Total non-current regulatory assets		$ 1,463,357	$ 1,389,489

(a) This asset represents the future recovery of pension benefit obligations and expense through retail rates. If these costs are disallowed by the ACC, this regulatory asset would be charged to other comprehensive income/loss and result in lower future revenues. The 2022 Rate Case decision allows for the full return on the pension asset in rate base. See Note 9 for further discussion.
(b) This asset relates to the acquisition of previously leased interest in Palo Verde Unit 2. See Note 12.
(c) See "Cost Recovery Mechanisms" discussion above.
(d) Subject to a carrying charge.
(e) Collected in retail rates.
(f) There are no regulatory assets for which the ACC has allowed recovery of costs, but not allowed a return by exclusion from rate base. FERC rates are set using a formula rate as described in "Transmission Rates, TCA, and Other Transmission Matters."

The detail of regulatory liabilities is as follows (dollars in thousands):

	Amortization Through	December 31, 2025	December 31, 2024
Excess deferred income taxes - ACC — Tax Cuts and Jobs Act (a)	2046	$ 847,572	$ 888,896
Excess deferred income taxes - FERC — Tax Cuts and Jobs Act (a)	2058	200,161	207,400
AROs and removal costs	(b)	286,907	358,403
Other postretirement benefits	(c)	233,952	238,113
Four Corners coal reclamation	2038	97,988	77,532
Income taxes — deferred investment tax credit	2056	81,949	66,327
Income taxes — change in rates	2054	56,260	59,133
RES (d)	2026	54,551	68,523
DSM (d)	2025	26,228	23,927
Sundance maintenance	2031	25,668	23,086
Spent nuclear fuel	2027	20,492	26,818
TCA Balancing Account (d)	2027	4,860	14,834
TEAM (d)	2032	3,738	4,343
Deferred fuel and purchased power — mark-to-market (Note 13)	2028	3,641	—
Other	Various	3,063	4,898
Total regulatory liabilities		$ 1,947,030	$ 2,062,233
Less: current regulatory liabilities		$ 210,909	$ 206,955
Total non-current regulatory liabilities		$ 1,736,121	$ 1,855,278

(a) For purposes of presentation on the Statements of Cash Flows, amortization of the regulatory liabilities for excess deferred income taxes are reflected as "Deferred income taxes" under Cash Flows From Operating Activities.
(b) In accordance with regulatory accounting, APS accrues removal costs for its regulated assets, even if there is no legal obligation for removal.
(c) See Note 9.
(d) See "Cost Recovery Mechanisms" discussion above.

9. Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan (The Pinnacle West Capital Corporation Retirement Plan) and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and its subsidiaries. All new employees participate in the account balance plan. Defined benefit plans specify the amount of benefits a plan participant is to receive using information about the participant. The pension plan covers nearly all employees. The supplemental excess benefit retirement plan covers officers of the Company and highly compensated employees designated for participation by the Board of Directors. Our employees do not contribute directly to the plans. We calculate the benefits based on age, years of service and pay.

Pinnacle West also sponsors other postretirement benefit plans (Pinnacle West Capital Corporation Group Life and Medical Plan and Pinnacle West Capital Corporation Post-65 Retiree Health Reimbursement Arrangement "HRA") for the employees of Pinnacle West and its subsidiaries. These plans provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plan, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions. We retain the right to change or eliminate these benefits.

Pinnacle West uses a December 31 measurement date each year for its pension and other postretirement benefit plans. The market-related value of our plan assets is their fair value at the measurement date. See Note 17 for further discussion of how fair values are determined. Due to subjective and complex judgments, which may be required in determining fair values, actual results could differ from the results estimated through the application of these methods.

A significant portion of the changes in the actuarial gains and losses of our pension and postretirement plans is attributable to APS and are recoverable in rates. Accordingly, these changes are recorded as a regulatory asset or regulatory liability. Our retail rates provide for the inclusion of annual benefit expense, which allows for recovery or return of this regulatory asset/liability. See Note 8.

The following table provides detail of the plans' net periodic benefit costs and the portion of these costs charged to expense (including administrative costs and excluding amounts capitalized as overhead construction or billed to electric plant participants) (dollars in thousands):

	Pension Plans			Other Benefits Plans		
	2025	2024	2023	2025	2024	2023
Service cost-benefits earned during the period	$ 44,153	$ 43,641	$ 39,461	$ 8,081	$ 9,955	$ 8,567
Non-service costs (credits):						
Interest cost on benefit obligation	155,121	148,643	153,561	20,345	22,169	22,509
Expected return on plan assets	(178,793)	(188,651)	(182,938)	(48,569)	(46,834)	(43,486)
Amortization of:						
Prior service credit (a)	—	—	—	(1,265)	(37,789)	(37,789)
Net actuarial loss (gain)	46,731	41,915	38,420	(11,727)	(8,676)	(9,614)
Net periodic benefit costs (credits)	$ 67,212	$ 45,548	$ 48,504	$ (33,135)	$ (61,175)	$ (59,813)
Portion of costs (credits) charged to expense	$ 38,977	$ 23,652	$ 27,029	$ (25,736)	$ (45,557)	$ (43,408)

(a) Prior-service costs or credits reflect the impact of modifications to the pension or postretirement plan benefits. The impact of these modifications is amortized over a period which reflects the demographics of the impacted population. In 2014, Pinnacle West made changes to the postretirement benefits offered to Medicare eligible retirees which resulted in prior-service credits. We have been amortizing these prior-serviced credits since 2015, and they became fully amortized as of January 31, 2025.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the plans' changes in the benefit obligations and funded status (dollars in thousands):

	Pension Plans		Other Benefits Plans	
	2025	2024	2025	2024
Change in Benefit Obligation				
Benefit obligation at January 1	$ 2,792,309	$ 2,908,063	$ 360,090	$ 430,434
Service cost	44,153	43,641	8,081	9,955
Interest cost	155,121	148,643	20,345	22,169
Benefit payments	(226,888)	(216,238)	(28,293)	(30,516)
Actuarial (gain) loss	79,363	(91,800)	7,759	(71,952)
Other plan changes	6,752	—	—	—
Benefit obligation at December 31	2,850,810	2,792,309	367,982	360,090
Change in Plan Assets				
Fair value of plan assets at January 1	2,639,862	2,835,549	702,192	696,494
Actual return on plan assets	244,343	4,518	65,124	32,816
Benefit payments	(213,684)	(200,205)	—	(27,118)
Fair value of plan assets at December 31	2,670,521	2,639,862	767,316	702,192
Funded (Underfunded) Status at December 31	$ (180,289)	$ (152,447)	$ 399,334	$ 342,102

The following table shows information for pension plans with an accumulated obligation in excess of plan assets (dollars in thousands):

	As of December 31,	
	2025	2024
Accumulated benefit obligation	$ 113,245	$ 113,541
Fair value of plan assets	—	—

The Pinnacle West Capital Corporation Retirement Plan is more than 100% funded on an accumulated benefit obligation basis at December 31, 2025, and December 31, 2024, therefore, the only pension plan with an accumulated benefit obligation in excess of plan assets in 2025 and 2024 is the non-qualified supplemental excess benefit retirement plan.

The following table shows information for pension plans with a projected benefit obligation in excess of plan assets (dollars in thousands):

	As of December 31,	
	2025	2024
Projected benefit obligation	$ 2,850,810	$ 2,792,309
Fair value of plan assets	2,670,521	2,639,862

The Pinnacle West Capital Corporation Retirement Plan, on a projected benefit obligation basis, was 98% funded at December 31, 2025, and 99% funded at December 31, 2024. In the table above, we included both the projected benefit obligation and the fair value of plan assets for our qualified pension plan and our non-qualified supplemental excess benefit retirement plan.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the amounts recognized on the Consolidated Balance Sheets (dollars in thousands):

	Pension Plans		Other Benefits Plans	
	2025	2024	2025	2024
Noncurrent asset	$ —	$ —	$ 399,334	$ 342,102
Current liability	(12,653)	(13,130)	—	—
Noncurrent liability	(167,636)	(139,317)	—	—
Net amount recognized (funded status)	$ (180,289)	$ (152,447)	$ 399,334	$ 342,102

The following table shows the details related to accumulated other comprehensive loss (gain) as of December 31, 2025, and 2024 (dollars in thousands):

	Pension Plans		Other Benefits Plans	
	2025	2024	2025	2024
Net actuarial loss (gain)	$ 760,502	$ 793,421	$ (234,958)	$ (237,889)
Prior service cost (credit)	6,752	—	—	(1,265)
APS's portion recorded as a regulatory (asset) liability	(723,042)	(750,976)	233,952	238,113
Income tax expense (benefit)	(10,929)	(10,354)	703	611
Accumulated other comprehensive loss (gain)	$ 33,283	$ 32,091	$ (303)	$ (430)

The following table shows the weighted-average assumptions used for both the pension and other benefits to determine benefit obligations and net periodic benefit costs:

	Benefit Obligations As of December 31,		Benefit Costs Year Ended December 31,		
	2025	2024	2025	2024	2023
Discount rate – pension plans	5.36 %	5.68 %	5.68 %	5.21 %	5.56 %
Discount rate – other benefits plans	5.43 %	5.71 %	5.71 %	5.23 %	5.58 %
Rate of compensation increase	4.50 %	4.50 %	4.50 %	4.52 %	4.57 %
Expected long-term return on plan assets - pension plans	N/A	N/A	7.05 %	6.90 %	6.70 %
Expected long-term return on plan assets - other benefit plans	N/A	N/A	7.05 %	6.85 %	6.80 %
Initial healthcare cost trend rate (pre-65 participants)	6.50 %	6.50 %	6.50 %	6.25 %	6.50 %
Ultimate healthcare cost trend rate (pre-65 participants)	4.50 %	4.50 %	4.50 %	4.75 %	4.75 %
Number of years to ultimate trend rate (pre-65 participants)	7	6	6	4	5
Initial healthcare cost trend rate (post-65 participants) (a)	N/A	1.00 %	1.00 %	2.00 %	2.00 %
Ultimate healthcare cost trend rate (post-65 participants) (a)	N/A	— %	N/A	2.00 %	2.00 %
Interest crediting rate – cash balance pension plans	4.51 %	4.66 %	4.66 %	4.54 %	4.50 %

(a) The Company has decided and has communicated to retirees that the increase in 2026 will be 1% with no further indexation in future years. Therefore, no assumption is being made for the Post-65 HRA subsidy trend rate.

In selecting the pretax expected long-term rate of return on plan assets, we consider past performance and economic forecasts for the types of investments held by the plan. For 2026, we are assuming a 6.90% long-term rate of return for pension assets and 7.00% (before tax) for other benefit assets, which we believe is reasonable given our asset allocation in relation to historical and expected performance.

In selecting our healthcare trend rates, we consider past performance and forecasts of healthcare costs.

Plan Assets

The Board of Directors has delegated oversight of the pension and other postretirement benefit plans' assets to an Investment Management Committee ("Committee"). The Committee has adopted investment policy statements ("IPS") for the pension and the other postretirement benefit plans' assets. The investment strategies for these plans include external management of plan assets.

The overall strategy of the pension plan's IPS is to achieve an adequate level of trust assets relative to the benefit obligations. To achieve this objective, the plan's investment policy provides for mixes of investments including long-term fixed income assets and return-seeking assets. The target allocation between return-seeking and long-term fixed income assets is defined in the IPS. The plan's funded status is reviewed on at least a monthly basis.

Changes in the value of long-term fixed income assets, also known as liability-hedging assets, are intended to offset changes in the benefit obligations due to changes in interest rates. Long-term fixed income assets consist primarily of fixed income debt securities issued by the U.S. Treasury and other government agencies, U.S. Treasury futures contracts, and fixed income debt securities issued by corporations. Long-term fixed income assets may also include interest rate swaps, and other instruments.

Return-seeking assets are intended to provide a reasonable long-term rate of investment return with a prudent level of volatility. Return-seeking assets are composed of U.S. equities, international equities, and alternative investments. International equities include investments in both developed and emerging markets. Alternative investments may include investments in real estate, private debt and various other strategies. The plan may also hold investments in return-seeking assets by holding securities in partnerships, common and collective trusts, and mutual funds.

Based on the IPS, the target and actual allocation for the pension plan at December 31, 2025, are as follows:

	Target Allocation	Actual Allocation
Long-term fixed income assets	80 %	78 %
Return-seeking assets	20 %	22 %
Total	100 %	100 %

The permissible range is within +/-5% of the target allocation shown in the above table, and also considers the plan's funded status.

The following table presents the additional target allocations, as a percent of total pension plan assets, for the return-seeking assets:

	Target Allocation
Equities in US and other developed markets	12 %
Equities in emerging markets	4 %
Alternative investments	4 %
Total	20 %

The pension plan IPS does not provide for a specific mix of long-term fixed income assets but does expect the average credit quality of such assets to be investment grade.

As of December 31, 2025, the asset allocation for other postretirement benefit plan assets is governed by the IPS for those plans, which provides for different asset allocation target mixes depending on the characteristics of the liability. The following table presents the actual allocations of the investment for the other postretirement benefit plan at December 31, 2025:

	Actual Allocation
Long-term fixed income assets	59 %
Return-seeking assets	41 %
Total	100 %

See Note 17 for a discussion on the fair value hierarchy and how fair value methodologies are applied. The plans invest directly in fixed income, U.S. Treasury futures contracts, and equity securities, in addition to investing indirectly in fixed income securities, equity securities and real estate through the use of mutual funds, partnerships and common and collective trusts. Equity securities held directly by the plans are valued using quoted active market prices from the published exchange on which the equity security trades and are classified as Level 1. U.S. Treasury futures contracts are valued using the quoted active market prices from the exchange on which they trade and are classified as Level 1. Fixed income securities issued by the U.S. Treasury held directly by the plans are valued using quoted active market prices and are classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies are primarily valued using quoted inactive market prices, or quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield, maturity, and credit quality. These instruments are classified as Level 2.

Mutual funds, partnerships, and common and collective trusts are valued utilizing a net asset value (“NAV”) concept or its equivalent. Mutual funds, which includes exchange traded funds (“ETFs”), are classified as Level 1, and valued using a NAV that is observable and based on the active market in which the fund trades.

Common and collective trusts are maintained by banks or investment companies and hold certain investments in accordance with a stated set of objectives (such as tracking the performance of the S&P 500 Index). The trust’s shares are offered to a limited group of investors and are not traded in an active market. Investments in common and collective trusts are valued using NAV as a practical expedient and, accordingly, are not classified in the fair value hierarchy. The NAV for trusts investing in exchange traded equities, and fixed income securities is derived from the market prices of the underlying securities held by the trusts. The NAV for trusts investing in real estate is derived from the appraised values of the trust’s underlying real estate assets.

Investments in partnerships are also valued using the concept of NAV as a practical expedient and, accordingly, are not classified in the fair value hierarchy. The NAV for these investments is derived from the value of the partnerships’ underlying assets. The plan’s partnerships holdings relate to investments in high-yield fixed income instruments. Certain partnerships also include funding commitments that may require the plan to contribute up to $50 million to these partnerships; as of December 31, 2025, approximately $38 million of these commitments have been funded.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The plans' trustee provides valuation of our plan assets by using pricing services that utilize methodologies described to determine fair market value. We have internal control procedures to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee's internal operating controls and valuation processes.

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2025, by asset category, are as follows (dollars in thousands):

	Level 1	Level 2	Other (a)	Total
Pension Plan:				
Cash and cash equivalents	$ 1,756	$ —	$ —	$ 1,756
Fixed income securities:				
Corporate	—	1,300,163	—	1,300,163
U.S. Treasury	607,621	—	—	607,621
Other (b)	—	120,483	—	120,483
Common stock equities (c)	73,548	—	—	73,548
Mutual funds (d)	115,478	—	—	115,478
Common and collective trusts:				
Equities	—	—	266,624	266,624
Real estate	—	—	114,782	114,782
Other (e)	—	—	70,066	70,066
Total	$ 798,403	$ 1,420,646	$ 451,472	$ 2,670,521
Other Benefits:				
Cash and cash equivalents	$ 475	$ —	$ —	$ 475
Fixed income securities:				
Corporate	—	200,469	—	200,469
U.S. Treasury	165,294	—	—	165,294
Other (b)	—	10,997	—	10,997
Common stock equities (c)	98,296	—	—	98,296
Mutual funds (d)	27,986	—	—	27,986
Common and collective trusts:				
Equities	—	—	167,103	167,103
Real estate	—	—	20,228	20,228
Other (e)	69,954	—	6,514	76,468
Total	$ 362,005	$ 211,466	$ 193,845	$ 767,316

(a) These investments primarily represent assets valued using NAV as a practical expedient and have not been classified in the fair value hierarchy.
(b) This category consists primarily of debt securities issued by municipalities and asset backed securities.
(c) This category primarily consists of U.S. common stock equities.
(d) These funds invest in international common stock equities.
(e) Primarily relates to short-term investment funds and includes plan receivables and payables.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2024, by asset category, are as follows (dollars in thousands):

	Level 1	Level 2	Other (a)	Total
Pension Plan:				
Cash and cash equivalents	$ 9,055	$ —	$ —	$ 9,055
Fixed income securities:				
Corporate	—	1,325,833	—	1,325,833
U.S. Treasury	561,317	—	—	561,317
Other (b)	—	133,254	—	133,254
Common stock equities (c)	74,939	—	—	74,939
Mutual funds (d)	102,722	—	—	102,722
Common and collective trusts:				
Equities	—	—	244,734	244,734
Real estate	—	—	127,397	127,397
Other (e)	—	—	60,611	60,611
Total	$ 748,033	$ 1,459,087	$ 432,742	$ 2,639,862
Other Benefits:				
Cash and cash equivalents	$ 840	$ —	$ —	$ 840
Fixed income securities:				
Corporate	—	186,435	—	186,435
U.S. Treasury	204,274	—	—	204,274
Other (b)	—	12,585	—	12,585
Common stock equities (c)	89,685	—	—	89,685
Mutual funds (d)	23,415	—	—	23,415
Common and collective trusts:				
Equities	—	—	140,178	140,178
Real estate	—	—	19,474	19,474
Other (e)	19,145	—	6,161	25,306
Total	$ 337,359	$ 199,020	$ 165,813	$ 702,192

(a) These investments primarily represent assets valued using NAV as a practical expedient and have not been classified in the fair value hierarchy.
(b) This category consists primarily of debt securities issued by municipalities and asset backed securities.
(c) This category primarily consists of U.S. common stock equities.
(d) These funds invest in U.S. and international common stock equities.
(e) Primarily relates to short-term investment funds and includes plan receivables and payables.

Contributions

Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. In 2025 and 2024, we did not make any contributions to our pension plan. The expected minimum required cash contributions for the pension plan are zero for the next three years and we do not expect to make any voluntary contributions in 2026, 2027 or 2028; however, we continue to evaluate and assess our ongoing contribution strategy. With regard to contributions to our other postretirement benefit plan, we did not make a contribution in 2025 or 2024 and do not expect to make any contributions in 2026, 2027 or 2028. For retiree medical claims from the other postretirement benefit plan trust assets, there was not a reimbursement received in 2025. The Company was reimbursed $27 million in 2024, and $23 million in 2023 for prior years retiree medical claims from the other postretirement benefit plan trust assets.

Estimated Future Benefit Payments

Benefit payments, which reflect estimated future employee service, for the next five years and the succeeding five years thereafter, are estimated to be as follows (dollars in thousands):

Year	Pension Plans	Other Benefits Plans
2026	$ 244,947	$ 28,075
2027	232,977	27,751
2028	235,256	27,443
2029	235,980	27,357
2030	235,953	27,206
Years 2031-2035	1,149,488	137,689

Electric plant participants contribute to the above amounts in accordance with their respective participation agreements.

Employee Savings Plan Benefits

Pinnacle West sponsors a defined contribution savings plan for eligible employees of Pinnacle West and its subsidiaries. In 2025, costs related to APS's employees represented 99% of the total cost of this plan. In a defined contribution savings plan, the benefits a participant receives result from regular contributions participants make to their own individual account, the Company's matching contributions and earnings or losses on their investments. Under this plan, the Company matches a percentage of the participants' contributions in cash which is then invested in the same investment mix as participants elect to invest their own future contributions. Pinnacle West recorded expenses for this plan of approximately $14 million for 2025, $14 million for 2024, and $12 million for 2023.

10. Stock-Based Compensation

Pinnacle West has incentive compensation plans under which stock-based compensation is granted to officers, key employees, and non-officer members of the Board of Directors. Awards granted under the 2021 Long-Term Incentive Plan, as amended ("2021 Plan"), may be in the form of stock grants, restricted stock units, stock units, performance shares, restricted stock, dividend equivalents, performance share units, performance cash, incentive and non-qualified stock options, and stock appreciation rights. The 2021 Plan authorizes up to 4.3 million common shares to be available for grant. As of December 31, 2025, 2.5 million common shares were available for issuance under the 2021 Plan. During 2025, 2024 and 2023, the Company granted awards in the form of restricted stock units, stock units, stock grants, and performance shares. Awards granted from 2012 to May 2021 were issued under the 2012 Long-Term Incentive Plan ("2012 Plan"), and awards granted from 2007 to 2011 were issued under the 2007 Long-Term Incentive Plan ("2007 Plan"). No new awards may be granted under the 2012 or 2007 Plans.

Stock-Based Compensation Expense and Activity

Compensation cost included in net income for stock-based compensation plans was $27 million in 2025, $24 million in 2024, and $17 million in 2023. The compensation cost capitalized is immaterial for all years. Income tax benefits related to stock-based compensation arrangements were $12 million in 2025, $6 million in 2024, and $3 million in 2023.

As of December 31, 2025, there were approximately $42 million of unrecognized compensation costs related to nonvested stock-based compensation arrangements. We expect to recognize these costs over a weighted-average period of 2 years.

The total fair value of shares vested was $27 million in 2025, $24 million in 2024, and $24 million in 2023.

The following table is a summary of awards granted and the weighted-average grant date fair value for each of the last 3 years:

	Restricted Stock Units, Stock Grants, and Stock Units (a)			Performance Shares (b)		
	2025	2024	2023	2025	2024	2023
Units granted	204,886	261,808	192,295	164,220	225,516	202,562
Weighted-average grant date fair value	$ 90.25	$ 71.10	$ 74.32	$ 97.72	$ 72.89	$ 79.61

(a) The units granted do not include awards that will be cash settled in 2025, 2024 or 2023. See below for additional information on restricted stock unit grants.
(b) Reflects the target payout level.

The following table shows the change of nonvested awards:

	Restricted Stock Units, Stock Grants, and Stock Units		Performance Shares	
	Shares	Weighted-Average Grant Date Fair Value	Shares (b)	Weighted-Average Grant Date Fair Value
Nonvested at December 31, 2024	460,791	$ 71.72	390,551	$ 77.29
Granted	204,886	90.25	164,220	97.72
Vested	(186,883)	73.77	(169,682)	77.94
Forfeited (c)	(15,856)	79.59	(13,535)	85.01
Nonvested at December 31, 2025	462,938 (a)	78.82	371,554	83.48
Vested Awards Outstanding at December 31, 2025	76,758		169,682	

(a) Includes no awards that will be cash settled.
(b) The performance shares are reflected at target payout level.
(c) We account for forfeitures as they occur.

Share-based liabilities paid relating to restricted stock units were $14 million, $8 million, and $6 million in 2025, 2024 and 2023, respectively. This includes cash used to settle restricted stock units of $1 million, $2 million, and $3 million in 2025, 2024 and 2023, respectively. Restricted stock units that are cash settled are classified as liability awards. All performance shares are classified as equity awards.

Restricted Stock Units, Stock Grants, and Stock Units

Restricted stock units are granted to officers and key employees and typically vest and settle in equal annual installments over a 4-year period after the grant date. Vesting is typically dependent upon continuous service during the vesting period.

Beginning in 2022, restricted stock unit awards are issued in stock. Awards include a dividend equivalent feature that allows each award to accrue dividends and treat them as reinvested, from the date of grant until the applicable vesting date. If the award is forfeited the employee is not entitled to the accrued reinvested dividends on those shares. Awards granted to retirement-eligible employees will vest on a pro-rata basis upon the employee's retirement.

Prior to 2022, awardees typically elected to receive payment in either 100% stock, 100% cash, or 50% in cash and 50% in stock. Awards included a dividend equivalent feature that accrued dividend rights from the date of grant until the applicable vesting date, plus interest compounded quarterly. If the award was forfeited, the employee was not entitled to the accrued dividends on those shares. Awards granted to retirement-eligible employees typically vested upon the employee's retirement.

Compensation cost for restricted stock unit awards is based on the fair value of the award, with the fair value being the market price of our stock on the measurement date. Restricted stock unit awards that will be settled in cash are accounted for as liability awards, with compensation cost initially calculated on the date of grant using the Company's closing stock price and remeasured at each balance sheet date. Restricted stock unit awards that will be settled in shares are accounted for as equity awards, with compensation cost calculated using the Company's closing stock price on the date of grant. Compensation cost is recognized over the requisite service period based on the fair value of the award.

Stock grants are issued to non-officer members of the Board of Directors. They may elect to receive the stock grant, or to defer receipt until a later date and receive stock units in lieu of the stock grant. Beginning in 2023, payments for stock units are issued in stock and include a dividend equivalent feature that allows each award to accrue dividends and treat them as reinvested, from the date of grant until the applicable vesting date. Prior to 2023, members of the Board of Directors who elected to defer could elect to receive payment in either 100% stock, 100% cash, or 50% in cash and 50% in stock. The stock units prior to 2023 included a dividend equivalent feature that accrues dividend rights from the date of grant to the date of payment, plus interest compounded quarterly.

Performance Share Awards

Performance share awards are granted to officers and key employees. The awards contain separate performance metric criteria that affect the number of shares that may be received if, after the end of a 3-year performance period, the performance criteria are met.

Beginning in 2022, performance share awards contain three separate, unrelated performance criteria. The first performance criteria is based upon Pinnacle West's total shareholder return ("TSR") in relation to the TSR of other companies in a specified utility index (i.e., the TSR component). The second performance criteria is based upon Pinnacle West's earnings per share ("EPS") performance relative to an approved target (i.e., the EPS component). The third performance criteria is based upon APS's clean MW installed of renewable or other carbon free resources compared to the approved target (i.e., the Clean component). The exact number of shares issued is calculated separately for each performance component and can vary from 0% to 200% of the target award for each separate performance criteria. Shares received include a dividend equivalent feature that treats accrued dividends as reinvested, from the date of grant until the date of payment, equal to the number of vested performance shares. If the award is forfeited or if the performance criteria are not achieved, the employee is not entitled to the dividends on those shares. Awards granted to retirement-eligible employees will vest on a pro-rata basis upon the employee's retirement.

Prior to 2022, performance share awards had two performance criteria. The first performance criteria was based upon non-financial performance metrics (i.e., the Metric component). The second performance criteria was based upon Pinnacle West's TSR in relation to the TSR of other companies in a specified utility index (i.e., the TSR component). The exact number of shares issued will vary from 0% to 200% of the target award. Shares received included a dividend equivalent feature that allows accrued dividend rights from the date of grant until the date of payment, plus interest compounded quarterly, equal to the number of vested performance shares. If the award was forfeited, the employee was not entitled to the accrued dividends on those shares. Awards granted to retirement-eligible employees typically vested upon the employee's retirement.

Performance share awards are accounted for as equity awards, with compensation cost based on the fair value of the award on the grant date. Compensation cost relating to the EPS and Clean metric component of the respective awards is based on the Company's closing stock price on the date of grant, with compensation cost recognized over the requisite service period based on the number of shares expected to vest. Management evaluates the probability of meeting the EPS and Clean metric component at each balance sheet date. If the EPS and Clean metric component criteria are not ultimately achieved, no compensation cost is recognized relating to the EPS and Clean metric component, and any previously recognized compensation cost is reversed. Compensation cost relating to the TSR component of the respective awards is determined using a Monte Carlo simulation valuation model, with compensation cost recognized ratably over the requisite service period, regardless of the number of shares that actually vest.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

11. Jointly-Owned Facilities

APS shares ownership of some of its generating and transmission facilities with other companies. We are responsible for our share of operating costs which are included in the corresponding operating expenses on our Consolidated Statements of Income. We are also responsible for providing our own financing. Our share of operating expenses and utility plant costs related to these facilities is accounted for using proportional consolidation. The following table shows APS's interests in those jointly-owned facilities recorded on the Consolidated Balance Sheets at December 31, 2025 (dollars in thousands):

	Percent Owned		Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating facilities:					
Palo Verde Units 1 and 3	29.1 %		$ 2,094,060	$ 1,079,823	$ 13,230
Palo Verde Unit 2 (a)	23.9 %		925,562	567,731	7,343
Palo Verde Common	26.2 %	(b)	977,526	431,023	58,899
Palo Verde sale leaseback (a)			142,921	110,886	—
Four Corners Generating Station	63.0 %		1,941,053	747,931	19,378
Transmission facilities:					
Arizona Nuclear Power Project 500kV System	33.1 %	(b)	141,348	60,579	5,350
Navajo Southern System	25.1 %	(b)	89,856	40,548	1,645
Palo Verde — Yuma 500kV System	16.1 %	(b)	44,505	9,060	136
Four Corners Switchyards	56.9 %	(b)	86,706	25,810	118
Phoenix — Mead System	17.5 %	(b)	36,290	19,568	609
Palo Verde — Rudd 500kV System	50.0 %		96,428	35,842	3,343
Morgan — Pinnacle Peak System	63.2 %	(b)	119,104	31,283	75
Round Valley System	50.0 %		548	224	—
Palo Verde — Morgan System	87.5 %	(b)	268,202	52,822	392
Hassayampa — North Gila System	80.0 %		154,329	31,361	—
Cholla 500kV Switchyard	85.7 %		8,456	3,114	190
Saguaro 500kV Switchyard	60.0 %		42,795	16,324	800
Kyrene — Knox System	50.0 %		578	359	—

(a) See Note 12 for information related to the Palo Verde sale leaseback purchases.
(b) Weighted-average of interests.

12. Variable Interest Entities

Pinnacle West

Captive Insurance Cell VIE

To support our overall insurance program, Pinnacle West established a captive insurance cell to insure certain risks of Pinnacle West and our subsidiaries. The Captive is a protected separate cell captive insurance company sponsored by Energy Insurance Services, Inc ("EISI"). EISI is owned by Energy Insurance Mutual Limited Company and allows participating member sponsoring organizations, such as Pinnacle West, to insure risks using captive entities. Pinnacle West, through its contractual rights, has a controlling financial interest in the separate protected Captive cell's assets. Pinnacle West obtains all the benefits from the Captive and makes all the primary controlling decisions that economically impact the Captive. As a separate protected cell, Pinnacle West is the Captive's only participant. The Captive is a VIE for which Pinnacle West is the primary beneficiary. Accordingly, Pinnacle West consolidates the Captive.

Under a mutual business program participation agreement between the Captive and EISI, EISI will issue policies, make claim disbursements, claim expenses and other underwriting fees on behalf of the Captive, as necessary.

The Captive insures Pinnacle West and its subsidiaries for terrorism coverage, excess liability including certain wildfire coverage, excess property insurance, and excess employment practice liability. The Captive policies exclude nuclear liability at Palo Verde. See Note 14 for details regarding nuclear liability insurance. Claim payments to the insureds can only be made up to the amount of the Captive's available assets. In the event that claims exceed the Captive's available assets, Pinnacle West may be required to provide additional funding to the Captive. In addition to policies obtained through the Captive, Pinnacle West also has commercial and mutual insurance policies purchased through third-party insurers that may provide coverage if a loss event occurs.

As a result of consolidation, we eliminate intercompany transactions between Pinnacle West and the Captive and record the Captive's assets, liabilities and third-party operating activities. In consolidation, the Captive's insurance premium revenues derived from Pinnacle West policies are eliminated against the insurance premium expense recorded by Pinnacle West and our subsidiaries relating to insurance policy coverage provided by the Captive. Consolidation primarily resulted in Pinnacle West reflecting the Captive's investment holdings on its Consolidated Balance Sheets, and the Captive's investment gains and losses reflected through earnings on Pinnacle West's Consolidated Statements of Income.

Consolidation of the Captive resulted in an increase in Pinnacle West net income of the year ended December 31, 2025, 2024, and 2023 of $5 million, $5 million, and zero, respectively. These amounts are fully attributable to Pinnacle West shareholders. Consolidation impacts Pinnacle West Consolidated Income Statement's operations and maintenance expense, other income and other expense line items.

Pinnacle West's Consolidated Balance Sheets as of December 31, 2025 and 2024 include $40 million and $34 million of assets relating to the Captive that is reported within the other special use funds line item. See Notes 17 and 18 for additional details on these investment holdings.

APS's financial statements are not impacted by Pinnacle West's consolidation of the Captive VIE.

APS

Palo Verde Sale Leaseback VIEs

In 1986, APS entered into agreements with three separate VIE lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. As further described below, in September 2025, APS purchased two of the three leased interests, the two related lease agreements were terminated and VIE consolidation treatment was discontinued for those two leases. As of December 31, 2025, one VIE lease arrangement remains in effect.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In June 2025, APS executed purchase agreements relating to two of the three VIE lease arrangements and subsequently submitted filings with FERC requesting authorization of the acquisitions. On September 10, 2025, FERC issued an order authorizing the APS acquisition of these leased interests. On September 22, 2025, all closing conditions were satisfied and APS acquired the two leased Palo Verde interests from the VIE noncontrolling interest lessor owners for a combined total of approximately $199 million. The two related lease agreements were terminated, and APS no longer has payment obligations to these two VIE noncontrolling interest lessors. As a result of the acquisition and lease terminations, effective September 22, 2025, APS no longer holds a variable interest in these lessor trust entities and therefore no longer consolidates these two lessor VIEs. In accordance with GAAP, the purchase is accounted for as the acquisition of the VIE's noncontrolling interests. As a result of the purchases, APS's Consolidated Balance Sheet as of September 30, 2025, included $47 million of property, plant and equipment, net of accumulated depreciation, that was reclassified from the Palo Verde sale leaseback asset line item. The remaining $152 million of the $199 million purchase price represents the incremental market value above the VIE's net book value included in the consideration to acquire the noncontrolling interest. The $152 million was recorded as a new regulatory asset on the APS Consolidated Balance Sheet as of September 30, 2025.

As a result of these September 2025 purchases, APS' Consolidated Balance Sheets as of December 31, 2025, includes $47 million of property, plant, and equipment, net of accumulated depreciation; and a $152 million regulatory asset. In the 2025 Rate Case, APS has requested to recover the acquisition of the leased interests in future customer rates as an investment in plant assets, seeking a full cost of capital return on the $199 million investment. See Note 8. APS did not recognize a gain or loss as a result of deconsolidating these two VIE entities; accordingly, for the year ended December 31, 2025, the acquisition of the VIE leased interests had no impact on the APS Consolidated Statements of Income.

As of December 31, 2025, APS owns these previously leased interests, providing APS a total ownership interest in Palo Verde Unit 2 of 23.9%. APS's remaining leased interest in Palo Verde Unit 2 as of December 31, 2025, is approximately 5.2%. The VIE lease agreement that was not subject to the purchase agreements remains in effect and is not impacted by the purchase transactions.

Under the current remaining lease in effect, APS will retain the leased asset through 2033 and will be required to make payments relating to the lease in total of approximately $9 million annually for the period 2026 through 2033. At the end of the lease period, APS will have the option to purchase the leased asset at its fair market value, extend the lease for up to two years, or return the asset to the lessor. The lease terms give APS the ability to utilize the asset for a significant portion of the asset's economic life, and therefore provide APS with the power to direct activities of the VIE that most significantly impact the VIE's economic performance. Predominantly due to the lease terms, APS has been deemed the primary beneficiary of this VIE and therefore consolidates the VIE.

As a result of consolidation of the VIEs, we eliminate lease accounting and instead recognize depreciation expense, resulting in an increase in net income of $15 million in 2025 and $17 million for each of 2024 and 2023. The increase in net income is entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

Our Consolidated Balance Sheets include the following amounts relating to these VIEs (dollars in thousands):

	December 31, 2025	December 31, 2024 (a)
Palo Verde sale leaseback property, plant and equipment, net of accumulated depreciation	$ 32,035	$ 82,556
Equity — Noncontrolling interests	40,617	103,167

(a) Includes the two VIEs subject to the September 2025 purchase transactions described above.

Assets of the VIE are restricted and may only be used for payment to the noncontrolling interest holders. These assets are reported on our Consolidated Financial Statements.

APS is exposed to losses relating to the VIE upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to make specified payments to the VIE's noncontrolling equity participants and take title to the leased Unit 2 interest, which, if appropriate, may be required to be written-down in value. If such an event were to occur during the lease period, APS may be required to pay the noncontrolling equity participant approximately $177 million in 2026 and up to $267 million over the lease term.

For regulatory ratemaking purposes, the lease agreement continues to be treated as an operating lease, and as a result, we have recorded a regulatory asset relating to the arrangement.

13. Derivative Accounting

Derivative financial instruments are used to manage exposure to commodity price and transportation costs of electricity, natural gas, emissions allowances, and interest rates. Risks associated with market volatility are managed by utilizing various physical and financial derivative instruments, including futures, forwards, options, and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and natural gas. Derivative instruments that meet certain hedge accounting criteria may be designated as cash flow hedges and are used to limit our exposure to cash flow variability on forecasted transactions. The changes in market value of such instruments have a high correlation to price changes in the hedged transactions. Derivative instruments are also entered into for economic hedging purposes. While economic hedges may mitigate exposure to fluctuations in commodity prices, these instruments have not been designated as accounting hedges. Contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow are netted, which reduces both revenues and fuel and purchased power costs in our Consolidated Statements of Income, but does not impact our financial condition, net income, or cash flows.

Our derivative instruments, excluding those qualifying for a scope exception, are recorded on the Consolidated Balance Sheets as an asset or liability and are measured at fair value. See Note 17 for a discussion of fair value measurements. Derivative instruments may qualify for the normal purchases and normal sales scope exception if they require physical delivery, and the quantities represent those transacted in the normal course of business. Derivative instruments qualifying for the normal purchases and sales scope exception are accounted for under the accrual method of accounting and excluded from our derivative instrument discussion and disclosures below.

See Note 16 for details relating to Pinnacle West's equity forward sale agreements and convertible notes. These equity-linked transactions are indexed to Pinnacle West common stock and qualify for a derivative scope exception and as such are not subject to mark-to-market accounting and are excluded from the derivative disclosures below.

Energy Derivatives

For its regulated operations, APS defers for future rate treatment 100% of the unrealized gains and losses on energy derivatives pursuant to the PSA mechanism that would otherwise be recognized in income. Realized gains and losses on energy derivatives are deferred in accordance with the PSA to the extent the amounts are above or below the Base Fuel Rate. See Note 8. Gains and losses from energy derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

The following table shows the outstanding gross notional volume of energy derivatives, which represent both purchases and sales (does not reflect net position):

		Quantity	
Commodity	**Unit of Measure**	**December 31, 2025**	**December 31, 2024**
Power	Gigawatt-hour	542	1,051
Gas	Billion cubic feet	211	235

Gains and Losses from Energy Derivative Instruments

For the years ended December 31, 2025, 2024 and 2023, APS had no energy derivative instruments in designated accounting hedging relationships.

The following table provides information about gains and losses from energy derivative instruments not designated as accounting hedging instruments (dollars in thousands):

	Financial Statement	Year Ended December 31,		
Commodity Contracts	**Location**	**2025**	**2024**	**2023**
Net Loss Recognized in Income	Fuel and purchased power (a)	$ (50,566)	$ (88,522)	$ (370,145)

(a) Amounts are before the effect of PSA deferrals.

Energy Derivative Instruments in the Consolidated Balance Sheets

Our energy derivative transactions are typically executed under standardized or customized agreements, which include collateral requirements and, in the event of a default, would allow for the netting of positive and negative exposures associated with a single counterparty. Agreements that allow for the offsetting of positive and negative exposures associated with a single counterparty are considered master netting arrangements. Transactions with counterparties that have master netting arrangements are offset and reported net on the Consolidated Balance Sheets. Transactions that do not allow for offsetting of positive and negative positions are reported gross on the Consolidated Balance Sheets.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

We do not offset a counterparty's current energy derivative contracts with the counterparty's non-current energy derivative contracts, although our master netting arrangements would allow current and non-current positions to be offset in the event of a default. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, trade receivables and trade payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting tables presented below.

The following tables provide information about the fair value of APS's risk management activities reported on a gross basis and the impacts of offsetting. These amounts relate to commodity contracts and are located in the assets and liabilities from risk management activities lines of APS's Consolidated Balance Sheets (dollars in thousands):

As of December 31, 2025	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amounts Reported on Balance Sheets
Current assets	$ 12,640	$ (9,395)	$ 3,245	$ 5	$ 3,250
Investments and other assets	6,707	(1,570)	5,137	—	5,137
Total assets	19,347	(10,965)	8,382	5	8,387
Current liabilities	(41,970)	9,395	(32,575)	(2,566)	(35,141)
Deferred credits and other	(3,065)	1,570	(1,495)	—	(1,495)
Total liabilities	(45,035)	10,965	(34,070)	(2,566)	(36,636)
Total	$ (25,688)	$ —	$ (25,688)	$ (2,561)	$ (28,249)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to or received by counterparties, that is subject to offsetting.
(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $2,566 thousand and cash margin provided to counterparties of $5 thousand.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As of December 31, 2024	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amounts Reported on Balance Sheets
Current assets	$ 13,718	$ (3,158)	$ 10,560	$ 18	$ 10,578
Investments and other assets	6,610	(630)	5,980	—	5,980
Total assets	20,328	(3,788)	16,540	18	16,558
Current liabilities	(52,527)	3,158	(49,369)	(2,971)	(52,340)
Deferred credits and other	(10,076)	630	(9,446)	—	(9,446)
Total liabilities	(62,603)	3,788	(58,815)	(2,971)	(61,786)
Total	$ (42,275)	$ —	$ (42,275)	$ (2,953)	$ (45,228)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to or received by counterparties, that is subject to offsetting.
(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $2,971 thousand and cash margin provided to counterparties of $18 thousand.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by energy derivative counterparties and have risk management contracts with many energy derivative counterparties. As of December 31, 2025, we have four counterparties for which our exposure represents approximately 73% of Pinnacle West's $8.4 million of net risk management assets. This exposure relates to ISDA master agreements with the respective counterparties. The ISDA counterparties have an investment grade credit rating by either Standard & Poor's and/or Moody's. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of our trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these counterparties could default, resulting in a material impact on consolidated results of operations for a given period. Counterparties in the portfolio consist principally of financial institutions, major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. To manage credit risk, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

Certain of our energy derivative instrument contracts contain credit-risk-related contingent features including, among other things, investment grade credit rating provisions, credit-related cross-default provisions, and adequate assurance provisions. Adequate assurance provisions allow a counterparty with reasonable grounds for uncertainty to demand additional collateral based on subjective events and/or conditions. For those energy derivative instruments in a net liability position, with investment grade credit contingencies, the counterparties could demand additional collateral if our debt credit rating were to fall below investment grade (below BBB- for Standard & Poor's or Fitch or Baa3 for Moody's).

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides information about our energy derivative instruments that have credit-risk-related contingent features (dollars in thousands):

	December 31, 2025
Aggregate fair value of derivative instruments in a net liability position	$ 45,035
Additional collateral in the event credit-risk related contingent features were fully triggered (a)	11,171

(a) This amount is after counterparty netting and includes those contracts which qualify for scope exceptions, which are excluded from the derivative details above.

As of December 31, 2025, we also have energy related non-derivative instrument contracts, with investment grade credit-related contingent features, which could also require us to post additional collateral of approximately $710 million if our debt credit ratings were to fall below investment grade.

14. Commitments and Contingencies

Palo Verde Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the DOE in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE's breach of the Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste ("Standard Contract") for failing to accept Palo Verde's spent nuclear fuel and high level waste from January 1, 2007, through June 30, 2011, pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, which required DOE to pay the Palo Verde owners for certain specified costs paid by Palo Verde during the period January 1, 2007, through June 30, 2011. In addition, the settlement agreement provided APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2016, which was extended to December 31, 2025. APS is currently evaluating a proposed extension to the settlement to cover costs paid through December 31, 2028.

APS has recovered costs for eleven claims pursuant to the terms of the August 15, 2014 settlement agreement, for eleven separate time periods during July 1, 2011, through October 31, 2024. The DOE has approved and paid approximately $174.3 million for these claims (APS's share is approximately $50.7 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the ACC's decision from the 2017 rate case, this regulatory liability is being refunded to customers. On October 31, 2025, APS submitted its twelfth claim pursuant to the terms of the settlement agreement in the amount of approximately $15.4 million (APS's share is approximately $4.5 million). In February 2026, the DOE approved approximately $15.4 million of this claim.

Nuclear Insurance

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act ("Price-Anderson Act"), which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry-wide retrospective payment plan. This insurance limit is subject to an adjustment every five years based upon the aggregate percentage change in the Consumer Price Index. The most recent adjustment took effect on January 1, 2024. As of that date, in accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident up to approximately $16.3 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $500 million, which is provided by American Nuclear Insurers. The remaining balance of approximately $15.8 billion of liability coverage is provided through a mandatory, industry-wide retrospective premium program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be responsible for retrospective premiums. The maximum retrospective premium per reactor under the program for each nuclear liability incident is approximately $165.9 million, subject to a maximum annual premium of approximately $24.7 million per incident. Based on APS's ownership interest in the three Palo Verde units, APS's maximum retrospective premium per incident for all three units is approximately $144.9 million, with a maximum annual retrospective premium of approximately $21.6 million.

The Palo Verde participants maintain insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion. APS has also secured accidental outage insurance for a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and accidental outage insurance are provided by NEIL. APS is subject to retrospective premium adjustments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $24.2 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. Additionally, at the sole discretion of the NEIL Board of Directors, APS would be liable to provide approximately $66.4 million in deposit premium within 20 days of request as assurance to satisfy any site obligation of retrospective premium assessment. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions, sublimits, and exclusions.

Nuclear Wage Class Action Lawsuit

On July 11, 2025, APS, together with all 25 other U.S. nuclear power plant operators, was named in a class action lawsuit brought in the U.S. District Court in Maryland. The lawsuit alleges the country's nuclear operators have violated antitrust laws by agreeing to exchange compensation information and suppress compensation. The class action complaint has been brought on behalf of all persons employed in nuclear power generation in the U.S. from May 1, 2003 until the present and alleges violations of the Sherman Act. We are unable at this time to predict the outcome of this matter and whether it will have a material impact on our financial position, results of operations, or cash flows.

Captive Insurance Cell

Pinnacle West has established a captive insurance program to supplement commercial and mutual insurance coverage for certain risks. The Captive insures Pinnacle West and its subsidiaries for terrorism coverage, excess liability including certain wildfire coverage, excess property insurance, and excess employment practice liability. These coverages may be supplemented with commercial and mutual insurance coverage. The Captive policies exclude nuclear liability at Palo Verde. The Captive may hold investment assets in cash, cash equivalents, and equity and fixed income instruments, which in the event of an insured loss would be available to pay covered claims. In the event of an insured loss event, Pinnacle West may be required to provide additional funding to the Captive. The Captive is a VIE, and Pinnacle West is the primary beneficiary of the VIE and consolidates the assets and liabilities of the Captive. In addition to the policies obtained through the Captive, Pinnacle West also has commercial and mutual insurance policies purchased through third-party insurers that may provide coverage if a loss event occurs. See Note 12 for additional details.

Fuel and Purchased Power Commitments and Purchase Obligations

APS is party to various fuel and purchased power contracts and purchase obligations with terms expiring between 2026 and 2054 that include required purchase provisions. As of December 31, 2025, APS estimates the contract requirements to be approximately $1,811 million in 2026; $1,988 million in 2027; $2,149 million in 2028; $2,146 million in 2029; $2,392 million in 2030; and $32.2 billion thereafter. Fuel and purchased power commitments include purchases of coal, electricity, natural gas, renewable energy, nuclear fuel, and natural gas transportation. Purchase obligations may include commitments for capital expenditures and other obligations. However, these amounts may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances. These amounts include estimated commitments relating to purchased power lease contracts. In January 2026, certain purchased power lease contracts were modified resulting in an additional $694 million of purchase obligations, primarily relating to periods after 2030. See Note 20.

Of the various fuel and purchased power contracts mentioned above, some of those contracts for coal supply include take-or-pay provisions. The current coal contracts with take-or-pay provisions have terms expiring through 2031.

The following table summarizes our estimated coal take-or-pay commitments (dollars in thousands):

	Year Ended December 31,					
	2026	2027	2028	2029	2030	Thereafter (b)
Coal take-or-pay commitments (a)	$ 206,489	$ 206,813	$ 213,825	$ 221,098	$ 228,639	$ 236,461

(a) Total take-or-pay commitments are approximately $1.3 billion. The total net present value of these commitments using a 4.81% discount rate is approximately $1.1 billion.
(b) Through 2031.

APS may spend more to meet its actual fuel requirements than the minimum purchase obligations in our coal take-or-pay contracts. The following table summarizes actual amounts purchased under the coal contracts which include take-or-pay provisions for each of the last three years (dollars in thousands):

	Year Ended December 31,		
	2025	2024	2023
Total purchases	$ 213,113	$ 237,821	$ 255,219

Renewable Energy Credits

APS has entered into contracts to purchase renewable energy credits to comply with the RES. APS estimates the contract requirements to be approximately $24 million in 2026; $21 million in 2027; $18 million in 2028; $16 million in 2029; $14 million in 2030; and $21 million thereafter. These amounts do not include purchases of renewable energy credits that are bundled with energy.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Coal Mine Reclamation Obligations

APS must reimburse certain coal providers for final and contemporaneous coal mine reclamation. We account for contemporaneous reclamation costs as part of the cost of the delivered coal. We utilize site-specific studies of costs expected to be incurred in the future to estimate our final reclamation obligation. These studies utilize various assumptions to estimate the future costs. Based on the most recent reclamation studies, APS recorded an obligation for the coal mine final reclamation of approximately $160 million at December 31, 2025, and $171 million at December 31, 2024. Under our current coal supply agreements, APS expects to make payments for the final mine reclamation as follows: $21 million in 2026; $22 million in 2027; and $23 million in 2028. These funds are held in an escrow account and will be distributed to certain coal providers under the terms of the applicable coal supply agreements. Any amendments to current coal supply agreements may change the timing of the contribution or cost of final reclamation. The annual payments to the escrow account and final distribution to certain coal providers may be subject to adjustments based on escrow earnings.

Superfund and Other Related Matters

CERCLA establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who released, generated, transported to, or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible (each a “PRP”). PRPs may be strictly, jointly, and severally liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, OU3, in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater RI/FS. The RI/FS for OU3 was finalized and submitted to EPA at the end of 2022. EPA notified APS that the RI/FS was approved on September 11, 2024. On September 25, 2025, EPA executed a final ROD adopting the OU3 remedies proposed in the approved RI/FS OU3. APS’s expenditures related to this investigation and study are approximately $3 million. APS anticipates it may incur additional expenditures in the future, but because the final costs associated with remediation requirements set forth in the RI/FS and ROD are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated; however, APS does not expect the outcome to have a material impact on its financial position, results of operations, or cash flows.

In connection with APS’s status as a PRP for OU3, since 2013 APS and at least two dozen other parties have been defendants in various CERCLA lawsuits stemming from allegations that contamination from OU3 and elsewhere has impacted groundwater wells operated by the Roosevelt Irrigation District. At this time, only one active lawsuit remains pending in the U.S. District Court for Arizona, which concerns $8.3 million in remediation legal expenses. APS is unable to predict the outcome of any further litigation related to this claim or APS’s share of liability related to that claim; however, APS does not expect the outcome to have a material impact on its financial position, results of operations, or cash flows.

On February 28, 2022, EPA provided APS with a request for information under CERCLA related to APS’s Ocotillo power plant site located in Tempe, Arizona. In particular, EPA seeks information from APS regarding APS’s use, storage, and disposal of substances containing PFAS at the Ocotillo power plant site in order to aid EPA’s investigation into actual or threatened releases of PFAS into groundwater within the South Indian Bend Wash Superfund site. The South Indian Bend Wash Superfund site includes the

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APS Ocotillo power plant site. APS filed its response to this information request on April 29, 2022. On January 17, 2023, EPA contacted APS to inform APS that it would be commencing on-site investigations within the South Indian Bend Wash site, including the Ocotillo power plant, and performing a remedial investigation and feasibility study related to potential PFAS impacts to groundwater over the next two to three years. APS estimates that its costs to oversee and participate in the remedial investigation work will be approximately $1.7 million. At the present time, we are unable to predict the outcome of this matter, and any further expenditures related to necessary remediation, if any, or further investigations cannot be reasonably estimated.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of both conventional pollutants and GHG, water quality, wastewater discharges, solid waste, hazardous waste, and CCRs. These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates but cannot predict whether it will obtain such recovery. The following proposed and final rules could involve material compliance costs to APS.

Coal Combustion Waste

On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCRs, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the RCRA and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Such closure requirements are deemed “forced closure” or “closure for cause” of unlined surface impoundments and are the subject of the regulatory and judicial activities described below.

Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

- Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to either authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. ADEQ has taken steps to develop a CCR permitting program and proposed state regulations governing CCR permitting in the summer of 2024. On April 1, 2025, the Arizona Governor’s Regulatory Review Council approved ADEQ’s proposed rulemaking governing CCR permitting. ADEQ will submit an approval package to

EPA, which will have to approve the entire state program before it is operational. It remains unclear when EPA would approve that permitting program pursuant to the Water Infrastructure Improvements for the Nation Act. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits, which would impact facilities like Four Corners located on the Navajo Nation. The proposal remains pending.

- On March 1, 2018, as a result of a settlement with certain environmental groups, EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019 to add a specific health-based groundwater protection standard for boron, EPA has yet to take action on this proposal.

We cannot predict the outcome of these regulatory proceedings or when EPA will take final action on those matters that are still pending. Depending on the eventual outcome, the costs associated with APS's management of CCR could materially increase, which could affect our financial condition, results of operations, or cash flows.

On April 25, 2024, EPA took final action on a proposal to expand the scope of federal CCR regulations to address the impacts from historical CCR disposal activities that would have ceased prior to 2015. This new class of CCRMUs, which contain at least 1,000 tons of CCR, broadly encompass any location at an operating coal-fired power plant where CCRs would have been placed on land. As proposed, this would include not only historically closed landfills and surface impoundments but also prior applications of CCR beneficial use (with exceptions for historical roadbed and embankment applications). Existing CCR regulatory requirements for groundwater monitoring, corrective action, closure, post-closure care, and other requirements will be imposed on such CCRMUs. Under EPA's legacy 2024 CCRMU rule, initial CCRMU site surveys originally due to be completed by February 2026 and final site investigation reports by February 2027.

On February 10, 2026, EPA published a final rule extending multiple compliance deadlines applicable to CCRMUs established under the prior rule. The final rule extends the deadline for completing Parts One and Two of Facility Evaluation Reports by one year to February 2027 and February 2028, respectively. EPA also extended associated compliance deadlines for groundwater monitoring and certain closure requirements. On February 9, 2026, EPA sent to the Office of Management and Budget for review a rule proposal that is anticipated to provide more substantive changes to certain aspects of the legacy 2024 CCRMU rule.

APS is still in the process of evaluating the impacts of these CCRMU regulations on its business and cannot predict the outcome of any future rulemaking or other regulatory proceedings aimed at changing the current EPA CCRMU rules. Based on the information available to APS at this time, APS cannot reasonably estimate the cost of the entire CCRMU asset retirement obligation. Depending on the outcome of the pending legacy 2024 CCRMU rule amendments and APS's evaluations, the costs associated with APS's management of CCR could materially increase, which could affect our financial condition, results of operations, or cash flows.

APS currently disposes of CCR in ash ponds and dry storage areas at Four Corners. The Navajo Plant disposed of CCR only in a dry landfill storage area. The Cholla Plant disposed of CCR in ash ponds and dry storage areas prior to ceasing coal-fired operations. Additionally, the CCR rule requires ongoing, phased groundwater monitoring. As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must have ceased operating and initiated closure as of April 11, 2021 (except for those disposal units at Cholla that had been subject to alternative closure, which initiated closure work on June 30, 2025). APS completed the assessments of corrective measures on June 14, 2019; however, additional investigations and engineering analyses that will support the remedy selection are still underway. In addition, APS has also solicited input from the public and hosted public hearings as part of this process. APS's estimates for its share of corrective action and monitoring costs at Four Corners and Cholla are captured within the Asset Retirement Obligations, and Removal Costs within Regulatory Liabilities. As APS continues to implement the CCR rule's corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until we have fully completed the corrective action assessment and final remedy selection process, we cannot predict any ultimate impacts to APS; however, at this time APS does not believe that any potential changes to the cost estimate from the CCR rule's corrective action assessment process for Four Corners or Cholla would have a material impact on its financial condition, results of operations, or cash flows.

EPA Power Plant Carbon Regulations

EPA's regulation of carbon dioxide emissions from electric utility power plants has proceeded in fits and starts over most of the last decade. Starting on August 3, 2015, EPA finalized the Clean Power Plan, which was the agency's first effort at such regulation through system-wide generation dispatch shifting. Those regulations were subsequently repealed by EPA on June 19, 2019 and replaced by the Affordable Clean Energy regulations, which were a far narrower set of rules. While the U.S. Court of Appeals for the D.C. Circuit subsequently vacated the Affordable Clean Energy regulations on January 19, 2021, and ordered a remand for EPA to develop replacement regulations consistent with the original 2015 Clean Power Plan, the U.S. Supreme Court subsequently reversed that decision on June 30, 2022, holding that the Clean Power Plan exceeded EPA's authority under the Clean Air Act.

In the latest final regulations governing power plant carbon dioxide emissions, released April 25, 2024, EPA issued emission standards and guidelines for various subcategories of new and existing power plants. Unlike EPA's Clean Power Plan regulations from 2015, which took a broad, system-wide approach to regulating carbon emissions from electric utility fossil-fuel burning power plants, these new federal regulations are limited to measures that can be installed at individual power plants to limit planet-warming carbon-dioxide emissions.

Under current rules, carbon emission performance standards apply based on the annual capacity factors for new natural gas-fired combustion turbine power plants. The highest utilization combustion turbines must be retrofitted for CCS by 2032. Intermediate or low-load natural gas fired combustion turbines with 40% or less capacity factors do not require add-on pollution controls. Instead, natural gas-fired combustion turbines with capacity factors of up to 20% are effectively unregulated, while turbines with capacity factors over 20% and up to 40% are subject to carbon dioxide emission rate limitations.

For coal-fired power plants, instead of imposing regulations based on capacity and utilization, EPA finalized subcategories based on planned retirement dates. Facilities retiring before 2032 are effectively exempt from regulation; those that retire between 2032 and 2038 must co-fire with natural gas starting in 2030; and those that retire in 2039 or later must install CCS controls by 2032.

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As of May 10, 2024, several states, electric utility companies, affiliated trade associations, and other entities filed petitions for review of these regulations in the D.C. Circuit Court of Appeals. APS is participating in that litigation as part of an ad hoc coalition of electric utility companies, independent power producers, and trade groups, called Electric Generators for a Sensible Transition. On February 5, 2025, EPA filed an unopposed motion requesting that the D.C. Circuit Court of Appeals hold the GHG regulations case in abeyance for 60 days and withhold issuing an opinion while the new leadership at EPA evaluates the rule and determines how it wishes to proceed. On February 19, 2025, the Court granted EPA's motion. EPA subsequently filed a second motion asking the Court to keep the GHG regulations case in abeyance for an indefinite period of time given EPA's anticipated reconsideration of the rules, with EPA providing status reports every 90 days. The D.C. Circuit granted EPA's motion for an indefinite abeyance on April 25, 2025. We cannot predict the outcome of the litigation challenging EPA's current carbon emission standards for power plants.

If the current regulations were to remain in effect, they would likely lead to a material increase in APS's costs to build, operate, and maintain new, frequently operated gas-fired power plants. The regulatory deadlines in 2032 by which new, frequently operated gas-fired power plants must install CCS and achieve 90% capture efficiency may not be feasible. Future resource plans and procurement efforts implicating the development of such new generation remain pending and, as such, at this time APS is not able to quantify the financial impact associated with EPA's existing GHG regulations for power plants.

On June 11, 2025, EPA put forth a proposed rule with two scenarios for repealing the GHG regulations finalized in 2024. EPA's primary proposal entails a full repeal of the GHG regulations based on a finding that GHG emissions from fossil fuel-fired power plants do not present a "significant contribution" to dangerous air pollution, thereby eliminating the 2024 GHG power plant regulations in their entirety.

Under EPA's alternative proposal, only certain portions of the 2024 GHG regulations would be repealed based on a finding that they are unlawful, including the section 111(d) emission guidelines for existing fossil fuel-fired steam generating units (coal-fired power plants), the CCS-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base-load stationary combustion turbines (i.e., those operating at greater than 40% annual capacity factors). This targeted approach would eliminate the CCS and natural gas co-firing technology-based pollution limits that would apply to both existing coal-fired power plants and new gas-fired combustion turbine power plants. However, efficiency-based standards for new combustion turbines would remain in place under this alternative proposal.

EPA's proposed rule to repeal the 2024 GHG regulations was published in the Federal Register on June 17, 2025. Comments were due by August 7, 2025. We cannot predict the outcome of future rulemaking or other regulatory proceedings aimed at changing or eliminating the current EPA emission standards for power plants. Further changes to these regulations may also face judicial review. APS cannot predict the outcome of any such litigation.

Effluent Limitation Guidelines

EPA published ELG on October 13, 2020, and, based off those guidelines, APS completed a NPDES permit modification for Four Corners on December 1, 2023. The ELG standards finalized in October 2020 relaxed the "zero discharge" standard for bottom ash transport waters EPA finalized in September 2015. However, on April 25, 2024, EPA finalized new ELG regulations that once again require "zero discharge" standards for flows of bottom ash transport water at power plants like Four Corners. For power plants that permanently cease operations by December 31, 2034, such facilities can continue to comply with the 2020 ELG standards. APS is currently evaluating its compliance options for Four Corners based on the ELG regulations finalized in April 2024 and is assessing what impacts the new standards will have on our financial condition, results of operations, or cash flows.

On December 31, 2025, EPA published a final rule extending by five years the compliance deadlines for achieving the 2024 zero-discharge standards for bottom ash transport wastewater from year-end 2029 to year-end 2034, among other changes to the 2024 rulemaking. EPA is also collecting additional information on zero-discharge technologies, including cost and performance data, to inform future potential rulemakings to modify or relax the current zero-discharge ELG standards. We cannot predict the outcome of any future rulemaking or other regulatory proceedings aimed at modifying the current ELG standards.

EPA Good Neighbor Proposal for Arizona

On March 15, 2023, EPA issued its final Good Neighbor Plan for 23 states in order to ensure that the cross-state transport of ozone forming emissions does not interfere with downwind state compliance with the NAAQS. Thermal power plant emission limitations are a key aspect of these regulations, which involve emission allowance trading for NOx emissions. While Arizona was not among the 23 states subject to EPA's March 2023 final action, EPA announced on January 23, 2024, that it was proposing to add Arizona and New Mexico (along with two other additional states) to EPA's NOx emission allowance trading program finalized last year. That proposal involves adding these states to the Good Neighbor Plan and disapproving the corresponding provisions of each state's State Implementation Plan. Because APS operates thermal power plants within Arizona and those portions of the Navajo Nation within New Mexico, APS's power plants would be subject to EPA's Good Neighbor Plan upon finalization of this proposal. EPA's final Good Neighbor Plan is subject to ongoing judicial review in the D.C. Circuit Court of Appeals. On June 27, 2024, the U.S. Supreme Court granted a motion to stay the effectiveness of EPA's final Good Neighbor Plan pending the resolution of the litigation. As such, APS will not be impacted by the Good Neighbor Plan until the outcome of this litigation is finalized. In addition, on December 19, 2024, EPA announced that it was withdrawing its proposal to add Arizona (along with other western states) to the federal Good Neighbor Plan. On March 12, 2025, EPA announced its intention to reconsider the Good Neighbor Plan and on January 30, 2026, EPA published a proposed rule in the Federal Register that would approve Arizona's and New Mexico's State Implementation Plans concerning the cross-state transport of ozone forming emissions. Such approval, if finalized as proposed, would remove APS's operations in Arizona and New Mexico from the scope of future efforts to regulate such emissions. APS cannot predict the outcome of this pending regulatory action nor when EPA may take final action on this proposal. If finalized as proposed, this action would then be subject to judicial review and APS cannot predict the outcome of such litigation, if any arises. In addition, APS cannot predict the outcome of any future EPA efforts to add Arizona or New Mexico to a future federal program addressing the cross-state transport of ozone-forming emissions. Should a federal program like the Good Neighbor Plan ultimately be imposed on APS and its operations in Arizona and New Mexico, it would have material impact on both the costs to operate current APS power plants and APS's ability to develop new thermal generation to serve load. At this time, APS cannot predict the impact on the Company's financial condition, results of operations, or cash flows.

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Revised Mercury and Air Toxics Standard Proposal

On February 20, 2026, EPA issued a final rule repealing the 2024 revisions to MATS regulations governing emissions of toxic air pollution from existing coal-fired power plants. The repeal of the 2024 amendment means that MATS regulations revert to the pre-existing framework for MATS emission limits established in 2012. As a result, the 2024 revisions that would have increased the stringency of filterable particulate matter limits used to demonstrate compliance with MATS and required the use of continuous emissions monitoring systems to ensure compliance (as opposed to periodic performance testing) will not take effect for existing coal-fired power plants, such as Four Corners.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standard and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, RCRA, Superfund, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of APS's fossil-fuel powered plants or the willingness or ability of power plant participants to fund any required equipment upgrades or continue their participation in these plants. The economics of continuing to own certain resources, particularly our coal plants, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants, as well as other costs related to early retirement, but cannot predict whether it would obtain such recovery.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support commodity contract collateral obligations and other transactions. As of December 31, 2025, standby letters of credit totaled approximately $30.4 million and will expire through 2026, and surety bonds totaled approximately $23.3 million and will expire through 2028. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

We enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements. Most significantly, APS has agreed to indemnify the equity participants and other parties in the remaining Palo Verde sale leaseback transaction with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

Pinnacle West has issued parental guarantees and has provided indemnification under certain surety bonds for APS which were not material as of December 31, 2025. In connection with the sale of Pinnacle West's wholly-owned subsidiary, 4C Acquisition, LLC's 7% interest in Units 4 and 5 of Four Corners to NTEC, Pinnacle West guaranteed certain obligations that NTEC has to the other owners of Four Corners. Pinnacle West has not needed to perform under this guarantee. A maximum obligation is not explicitly stated in the guarantee and, therefore, the overall maximum amount of the obligation under such guarantee cannot be reasonably estimated; however, we consider the fair value of this guarantee, including expected credit losses, to be immaterial.

In connection with PNW Power's investments in minority ownership positions in the Clear Creek wind farm in Missouri and Nobles 2 wind farm in Minnesota, Pinnacle West has guaranteed the obligations of PNW Power to make PTC funding payments to borrowers of the projects (the "PTC Guarantees"). The amounts guaranteed by Pinnacle West are reduced as payments are made under the respective guarantee agreements. As of December 31, 2025, there is approximately $26.3 million remaining relating to these PTC Guarantees that are expected to terminate by 2031.

Pinnacle West issued various performance guarantees in connection with a joint venture project, the Kūpono Solar Project, by Pinnacle West's BCE subsidiary. BCE was sold to Ameresco in 2024 (the "BCE Sale"). See Note 22. Subsequent to the BCE Sale, Pinnacle West continues to maintain these Kūpono Solar Project investment financing guarantees and is exposed to losses relating to these guarantees upon the occurrence of certain events that we consider to be remote. Under the Kūpono Solar Project sale-leaseback financing, Pinnacle West has committed to certain performance guarantees that may apply upon the occurrence of specified events, such as uninsured loss events. Ameresco, the owner of the Kūpono Solar Project, has agreed to make efforts to refinance the project and eliminate these guarantees prior to 2030. Pinnacle West has not needed to perform under these guarantees. Maximum obligations are not explicitly stated in the guarantees and cannot be reasonably estimated. Ameresco is obligated to reimburse Pinnacle West for any payments made by Pinnacle West under such guarantees. We consider the fair value of these guarantees, including expected credit losses, to be immaterial.

15. Other Income and Other Expense

The following table provides detail of Pinnacle West's consolidated other income and other expense for the years ended 2025, 2024, and 2023 (dollars in thousands):

	2025	2024	2023
Other income:			
Interest income	$ 18,037	$ 24,322 (a)	$ 27,242 (a)
Investment gain — net (b)	26,720	—	—
Gain on sale of BCE (Note 22)	—	22,988	6,205
Miscellaneous	4,649	1,304	219
Total other income	$ 49,406	$ 48,614	$ 33,666
Other expense:			
Non-operating costs	$ (21,332)	$ (27,370) (c)	$ (15,260)
Investment losses — net	—	(1,418)	(3,402)
Miscellaneous	(8,933)	(5,348)	(6,394)
Total other expense	$ (30,265)	$ (34,136)	$ (25,056)

(a) 2023 and 2024 Interest income is primarily related to PSA interest. See Note 8.
(b) Investment gain is primarily related to El Dorado's equity investment in SAI. See Note 23.
(c) The 2024 Non-operating cost is primarily related to corporate giving.

The following table provides detail of APS's other income and other expense for the years ended 2025, 2024, and 2023 (dollars in thousands):

	2025	2024	2023
Other income:			
Interest income	$ 15,933	$ 21,088 (a)	$ 26,853 (a)
Miscellaneous	281	6	219
Total other income	$ 16,214	$ 21,094	$ 27,072
Other expense:			
Non-operating costs	$ (19,650)	$ (26,588) (b)	$ (14,070)
Miscellaneous	(6,732)	(3,110)	(4,194)
Total other expense	$ (26,382)	$ (29,698)	$ (18,264)

(a) 2023 and 2024 Interest income is primarily related to PSA interest. See Note 8.
(b) The 2024 Non-operating cost is primarily related to corporate giving.

16. Common Stock Equity and Earnings Per Share

At-the-Market Program

On November 8, 2024, Pinnacle West opened its ATM Program, pursuant to which Pinnacle West may sell, from time to time, up to $900 million of its common stock through an at-the-market equity distribution program, which includes the ability to enter into forward sale agreements. Approximately $700 million of common stock is available to be sold under the ATM Program, which takes into account the forward sale agreements in effect as of December 31, 2025.

As of December 31, 2025, Pinnacle West had four outstanding forward sale agreements under its ATM Program (collectively, the "ATM Forward Sale Agreements"). These agreements relate to approximately $200 million of common stock and may be settled at Pinnacle West's discretion by issuing shares at the applicable forward sales price or, alternatively, by delivering cash in lieu of shares. Pinnacle West also entered into a contract to begin a fifth ATM forward sale agreement in December 2025, transacting a total of $10.7 million with an effective date of January 5, 2026, and a maturity date of July 2, 2027.

The following table presents information about the outstanding ATM Forward Sale Agreements, including details of the outstanding forward sale agreements as of December 31, 2025:

ATM Forward Sale Agreements	Maturity Date	Number of Shares	Forward Sales Price Per Share (a)	Aggregate Value (in thousands)
November 2024	June 30, 2026	552,833	$ 89.73	$ 49,606
March 2025	September 14, 2026	544,959	$ 90.83	$ 49,499
August 2025	February 16, 2027	543,001	$ 91.21	$ 49,527
September 2025	February 22, 2027	558,622	$ 88.69	$ 49,544
		2,199,415	$ 90.10 (b)	$ 198,176

(a) Subject to certain adjustments.
(b) Weighted-average price for the total ATM Program.

Non-ATM February 2024 Forward Sale Agreements

In addition to the ATM Forward Sale Agreements, Pinnacle West also has Forward Sale Agreements that were entered into on February 28, 2024 (the "February 2024 Forward Sales Agreements"). These agreements may be settled at Pinnacle West's discretion by issuing shares of Pinnacle West common stock and receiving cash, if any, at the then-applicable forward sales price. The terms of the February 2024 Forward Sale Agreements also allow Pinnacle West, at its option, to settle the agreements with the counterparties by delivering cash, in lieu of shares. The February 2024 Forward Sale Agreements were partially settled in December 2024, September 2025, and December 2025. In August 2025, APS amended the February 2024 Forward Sale Agreements with Wells Fargo Bank, National Association, to extend the maturity date of those forward confirmations to December 31, 2026.

The following table presents information about the outstanding February 2024 Forward Sale Agreements as of December 31, 2025 (dollars in thousands, except price per share):

February 2024 Forward Sale Agreements	Number of Shares		Forward Sales Price Per Share		Aggregate Value	
Initial Price	11,240,601		$ 64.51	(a)	$ 725,131	
Settlements						
December 23, 2024	5,377,115	(b)	$ 64.17		$ 345,049	(c)
September 4, 2025	243,186	(b)	$ 63.12		$ 15,350	(c)
December 18, 2025	1,193,950	(b)	$ 62.82		$ 75,004	(c)

(a) Subject to certain adjustments.
(b) Physical delivery.
(c) Proceeds recorded in common equity on the Consolidated Balance Sheets.

Convertible Notes

In June 2024, Pinnacle West issued $525 million of 4.75% Convertible Senior Notes due 2027, which are senior unsecured obligations of Pinnacle West and will mature on June 15, 2027. Interest is payable semiannually in arrears on June 15 and December 15 of each year, beginning on December 15, 2024.

Prior to March 15, 2027, the holders of the Convertible Notes may elect at their option to convert all or any portion of their Convertible Notes under the following limited circumstances:

- during any calendar quarter (and only during such calendar quarter), if the sale price of Pinnacle West 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;

- during the five business day period after any 10 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 Pinnacle West common stock and the conversion rate on such trading day; or

- upon the occurrence of certain corporate events, as defined in the Convertible Notes' indenture.

On or after March 15, 2027, until the maturity date, the holders of the Convertible Notes may elect at their option to convert all or any portion of their notes. Upon conversion, Pinnacle West will pay cash up to the aggregate principal amount of the Convertible Notes converted and at Pinnacle West's sole discretion, pay or deliver cash, shares of Pinnacle West common stock or a combination of both, in respect to the remainder, if any, of Pinnacle West's conversion obligation in excess of the aggregate principal amount of the Convertible Notes being converted. The initial conversion rate, which is subject to certain adjustments as set forth in the indenture, is 10.8338 shares of common stock per $1,000 principal amount of Convertible Notes, which is equivalent to an initial conversion price of approximately $92.30 per share. The conversion rate is not subject to adjustment for any accrued and unpaid interest.

If Pinnacle West undergoes a fundamental change, as defined in the Convertible Notes' indenture, then, subject to certain conditions, holders of the Convertible Notes may require Pinnacle West to repurchase for cash all or any portion of its Convertible Notes at a 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.

As of December 31, 2025, the conditions allowing holders to convert their Convertible Notes were not met, and as a result, the Convertible Notes were classified as long term debt on Pinnacle West's Consolidated Balance Sheets with a carrying amount of $525 million, net of $4 million in unamortized debt issuance costs. The estimated fair value of the Convertible Notes as of December 31, 2025 was $561 million (Level 2 within the fair value hierarchy).

As of December 31, 2025, based on Pinnacle West's average stock price and the relevant terms of the Convertible Notes, there were no shares of Pinnacles West's common stock included in basic or diluted EPS relating to the potential conversion of the Convertible Notes.

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Earnings Per Share

The following table presents the calculation of Pinnacle West's basic and diluted EPS (dollars in thousands, except earnings per share amounts):

	As of December 31,		
	2025	2024	2023
Net income attributable to common shareholders	$ 616,531	$ 608,806	$ 501,557
Weighted average common shares outstanding — basic	119,687	113,846	113,442
Net effect of dilutive securities:			
Contingently issuable performance shares and restricted stock units	568	480	362
Dilutive shares related to equity forward sale agreements (a)	1,716	1,906	—
Total contingently issuable shares	2,284	2,386	362
Weighted average common shares outstanding — diluted	121,971	116,232	113,804
Earnings per weighted-average common share outstanding			
Net income attributable to common shareholders — basic	$ 5.15	$ 5.35	$ 4.42
Net income attributable to common shareholders — diluted	$ 5.05	$ 5.24	$ 4.41

(a) For the years ended December 31, 2025, 2024 and 2023 the diluted weighted-average common shares excludes 148,098, 1,038,463 and 0 shares, respectively relating to the ATM Program and the Convertible Notes. These potentially issuable shares were excluded from the calculation of diluted shares as their inclusion would have been antidilutive.

Pinnacle West's forward sale agreements are classified as equity transactions and are not recorded on the Pinnacle West Consolidated Balance Sheets until shares are settled. Delivery of shares to settle equity forward agreements will result in dilution to basic EPS upon settlement. Prior to settlement, the potentially issuable shares are reflected in our diluted EPS calculations using the treasury stock method. Under this method, the number of shares, if any, that would be issued upon settlement is reduced by the number of shares that could be purchased by Pinnacle West in the market with the proceeds received from issuance (based on the average market price during the reporting period). Share dilution occurs when the average market price of our stock during the reporting period is higher than the adjusted forward sale price as of the end of the reporting period.

On May 21, 2025, Pinnacle West shareholders approved an amendment to the Company's Articles of Incorporation to increase the number of authorized shares of common stock from 150,000,000 to 300,000,000. This amendment was subsequently filed with the ACC on May 22, 2025.

17. Fair Value Measurements

We classify our assets and liabilities that are carried at fair value within the fair value hierarchy. This hierarchy ranks the quality and reliability of the inputs used to determine fair values, which are then classified and disclosed in one of three categories. The three levels of the fair value hierarchy are:

Level 1 — Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date.

Level 2 — Other significant observable inputs, including quoted prices in active markets for similar assets or liabilities; quoted prices in markets that are not active, and model-derived valuations whose inputs are observable (such as yield curves).

Level 3 — Valuation models with significant unobservable inputs that are supported by little or no market activity. Instruments in this category may include long-dated derivative transactions where valuations are unobservable due to the length of the transaction, options, and transactions in locations where observable market data does not exist. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Thus, a valuation may be classified in Level 3 even though the valuation may include significant inputs that are readily observable. We maximize the use of observable inputs and minimize the use of unobservable inputs. We rely primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities. If market data is not readily available, inputs may reflect our own assumptions about the inputs market participants would use. Our assessment of the inputs and the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities as well as their placement within the fair value hierarchy levels. We assess whether a market is active by obtaining observable broker quotes, reviewing actual market activity, and assessing the volume of transactions. We consider broker quotes observable inputs when the quote is binding on the broker, we can validate the quote with market activity, or we can determine that the inputs the broker used to arrive at the quoted price are observable.

Certain instruments have been valued using the concept of Net Asset Value ("NAV") as a practical expedient. These instruments are typically structured as investment companies offering shares or units to multiple investors for the purpose of providing a return. These instruments are similar to mutual funds; however, their NAV is generally not published and publicly available, nor are these instruments traded on an exchange. Instruments valued using NAV as a practical expedient are included in our fair value disclosures; however, in accordance with GAAP are not classified within the fair value hierarchy levels.

Recurring Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, and investments held in the nuclear decommissioning trusts and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefit plans. See Note 7 for fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

Cash equivalents represent certain investments in money market funds that are valued using quoted prices in active markets.

Risk Management Activities — Energy Derivative Instruments

Exchange traded commodity contracts are valued using unadjusted quoted prices. For non-exchange traded commodity contracts, we calculate fair value based on the average of the bid and offer price, discounted to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed out or hedged. The credit valuation adjustment represents estimated credit losses on our net exposure to counterparties, taking into account netting agreements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. We maintain credit policies that management believes minimize overall credit risk.

Certain non-exchange traded commodity contracts are valued based on unobservable inputs due to the long-term nature of contracts, characteristics of the product, or the unique location of the transactions. Long-dated energy transactions may consist of observable valuations for the near-term portion and unobservable valuations for the long-term portions of the transaction. We rely primarily on broker quotes to value these instruments. When our valuations utilize broker quotes, we perform various control procedures to ensure the quote has been developed consistent with fair value accounting guidance. These controls include assessing the quote for reasonableness by comparison against other broker quotes, reviewing historical price relationships, and assessing market activity. When broker quotes are not available, the primary valuation technique used to calculate the fair value is the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at more illiquid delivery points.

When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3.

Investments Held in Nuclear Decommissioning Trusts and Other Special Use Funds

The nuclear decommissioning trusts and other special use funds invest in fixed income and equity securities. Other special use funds include the coal reclamation escrow account, the active union employee medical account, and the Captive. See Note 18 for additional discussion about our investment accounts.

We value investments in fixed income and equity securities using information provided by our trustees and escrow agent. Our trustees and escrow agent use pricing services that utilize the valuation methodologies described below to determine fair market value. We have internal control procedures designed to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustees' and escrow agent's internal operating controls and valuation processes.

Fixed Income Securities

Fixed income securities issued by the U.S. Treasury are valued using quoted active market prices and are typically classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies, including mortgage-backed instruments, are valued using quoted inactive market prices, quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield curves and spreads relative to such yield curves. These fixed income instruments are classified as Level 2. Whenever possible, multiple market quotes are obtained which enables a cross-check validation. A primary price source is identified based on asset type, class, or issue of securities.

Fixed income securities may also include short-term investments in certificates of deposit, variable rate notes, time deposit accounts, U.S. Treasury and Agency obligations, U.S. Treasury repurchase agreements, commercial paper, and other short-term instruments. These instruments are valued using active market prices or utilizing observable inputs described above.

Equity Securities

The nuclear decommissioning trusts' equity security investments are held indirectly through commingled funds. The commingled funds are valued using the funds' NAV as a practical expedient. The funds' NAV is primarily derived from the quoted active market prices of the underlying equity securities held by the funds. We may transact in these commingled funds on a daily basis at the NAV. The commingled funds are maintained by a bank and hold investments in accordance with the stated objective of tracking the performance of the S&P 500 Index. Because the commingled funds' shares are offered to a limited group of investors, they are not considered to be traded in an active market. As these instruments are valued using NAV, as a practical expedient, they have not been classified within the fair value hierarchy.

The nuclear decommissioning trusts and other special use funds may also hold equity securities that include exchange traded mutual funds and money market accounts for short-term liquidity purposes. These short-term, highly-liquid investments are valued using active market prices.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Fair Value Tables

The following table presents the fair value as of December 31, 2025 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
ASSETS						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 19,347	$ —	$ (10,960)	(a)	$ 8,387
Nuclear decommissioning trusts:						
Equity securities	18,970	—	—	(3,799)	(b)	15,171
U.S. commingled equity funds	—	—	—	500,592	(c)	500,592
U.S. Treasury debt	364,943	—	—	—		364,943
Corporate debt	—	242,176	—	—		242,176
Mortgage-backed securities	—	230,695	—	—		230,695
Municipal bonds	—	37,572	—	—		37,572
Other fixed income	—	23,017	—	—		23,017
Subtotal nuclear decommissioning trusts	383,913	533,460	—	496,793		1,414,166
Other special use funds:						
Equity securities	62,573	—	—	3,199	(b)	65,772
U.S. Treasury debt	369,055	—	—	—		369,055
Subtotal other special use funds (d)	431,628	—	—	3,199		434,827
Total assets	$ 815,541	$ 552,807	$ —	$ 489,032		$ 1,857,380
LIABILITIES						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (21,325)	$ (23,710)	$ 8,399	(a)	$ (36,636)

(a) Represents counterparty netting, margin, and collateral. See Note 13.
(b) Represents net pending securities sales and purchases.
(c) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.
(d) All amounts relate to APS, with the exception of $40.3 million related to Pinnacle West's Captive investments that are classified within Level 1 equity securities. See Note 12.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value at December 31, 2024 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
ASSETS						
Cash equivalents	$ 23	$ —	$ —	$ —		$ 23
Risk management activities — derivative instruments:						
Commodity contracts	—	13,152	7,176	(3,770)	(a)	16,558
Nuclear decommissioning trusts:						
Equity securities	11,859	542	—	3,335	(b)	15,736
U.S. commingled equity funds	—	—	—	423,069	(c)	423,069
U.S. Treasury debt	367,396	—	—	—		367,396
Corporate debt	—	203,180	—	—		203,180
Mortgage-backed securities	—	208,533	—	—		208,533
Municipal bonds	—	37,429	—	—		37,429
Other fixed income	—	27,502	—	—		27,502
Subtotal nuclear decommissioning trusts	379,255	477,186	—	426,404		1,282,845
Other special use funds:						
Cash equivalents	25,000	—	—	—	(d)	25,000
Equity securities	24,962	—	—	2,851	(b) (d)	27,813
U.S. Treasury debt	355,544	—	—	—		355,544
Subtotal other special use funds (d)	405,506	—	—	2,851		408,357
Total assets	$ 784,784	$ 490,338	$ 7,176	$ 425,485		$ 1,707,783
LIABILITIES						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (40,388)	$ (22,215)	$ 817	(a)	$ (61,786)

(a) Represents counterparty netting, margin, and collateral. See Note 13.
(b) Represents net pending securities sales and purchases.
(c) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.
(d) All amounts relate to APS, with the exception of $34.2 million related to Pinnacle West's Captive investments that are classified within Level 1, $25.0 million in cash equivalents and $9.2 million related to equity securities. See Note 12.

Fair Value Measurements Classified as Level 3

The significant unobservable inputs used in the fair value measurement of our energy derivative contracts include broker quotes that cannot be validated as an observable input primarily due to the long-term nature of the quote or other characteristics of the product. Significant changes in these inputs in isolation would result in significantly higher or lower fair value measurements. Changes in our derivative contract fair values, including changes relating to unobservable inputs, typically will not impact net income due to regulatory accounting treatment.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Because our forward commodity contracts classified as Level 3 are currently in a net purchase position, we would expect price increases of the underlying commodity to result in increases in the net fair value of the related contracts. Conversely, if the price of the underlying commodity decreases, the net fair value of the related contracts would likely decrease.

Other unobservable valuation inputs include credit and liquidity reserves, which do not have a material impact on our valuations; however, significant changes in these inputs could also result in higher or lower fair value measurements.

The following tables provide information regarding our significant unobservable inputs used to value our risk management derivative Level 3 instruments as of December 31, 2025 and December 31, 2024 (dollars in thousands):

	December 31, 2025 Fair Value		Valuation	Significant		Weighted-Average
Commodity Contracts	**Assets**	**Liabilities**	**Technique**	**Unobservable Input**	**Range**	**(b)**
Electricity Forward Contracts (a)	$ —	$ 21,913	Discounted cash flows	Electricity forward price (per MWh)	$41.51 - $149.37	$80.20
Natural Gas Forward Contracts (a)	—	1,797	Discounted cash flows	Natural gas forward price (per Million British Thermal Units (“MMBtu”))	$(0.07) - $0.36	$0.04
Total	$ —	$ 23,710				

(a) Includes swaps and physical and financial contracts.
(b) Unobservable inputs were weighted by the relative fair value of the instrument.

	December 31, 2024 Fair Value		Valuation	Significant		Weighted-Average
Commodity Contracts	**Assets**	**Liabilities**	**Technique**	**Unobservable Input**	**Range**	**(b)**
Electricity Forward Contracts (a)	$ 708	$ 21,890	Discounted cash flows	Electricity forward price (per MWh)	$ 25.25 - $151.11	$106.06
Natural Gas Forward Contracts (a)	6,468	325	Discounted cash flows	Natural gas forward price (per MMBtu)	$(0.89) - $1.47	$0.71
Total	$ 7,176	$ 22,215				

(a) Includes swaps and physical and financial contracts.
(b) Unobservable inputs were weighted by the relative fair value of the instrument.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the changes in fair value for our risk management activities' assets and liabilities that are measured at fair value on a recurring basis using Level 3 inputs (dollars in thousands):

	Year Ended December 31,	
Commodity Contracts	**2025**	**2024**
Balance at beginning of period	$ (15,039)	$ 4,921
Total net losses realized/unrealized:		
Deferred as a regulatory asset or liability	(30,006)	(60,965)
Settlements	21,907	44,156
Transfers into Level 3 from Level 2	(1,240)	(4,635)
Transfers from Level 3 into Level 2	668	1,484
Balance at end of period	$ (23,710)	$ (15,039)
Net unrealized gains/losses included in earnings related to instruments still held at end of period	$ —	$ —

Transfers in or out of Level 3 are typically related to our long-dated energy transactions that extend beyond available quoted periods.

Financial Instruments Not Carried at Fair Value

The carrying values of our short-term borrowings approximate fair value and are classified within Level 2 of the fair value hierarchy. See Note 6 for our long-term debt fair values.

18. Investments in Nuclear Decommissioning Trusts and Other Special Use Funds

We have investments in debt and equity securities held in nuclear decommissioning trusts and other special use funds. Investments in debt securities are classified as available-for-sale securities. We record both debt and equity security investments at their fair value on our Consolidated Balance Sheets. See Note 17 for a discussion of how fair value is determined and the classification of the investments within the fair value hierarchy. The investments in each trust or account are restricted for use and are intended to fund specified costs and activities as further described for each fund below.

Nuclear Decommissioning Trusts

APS established external decommissioning trusts in accordance with NRC regulations to fund the future costs APS expects to incur to decommission Palo Verde. Third-party investment managers are authorized to buy and sell securities per stated investment guidelines. The trust funds are invested in fixed income securities and equity securities. Earnings and proceeds from sales and maturities of securities are reinvested in the trusts. Because of the ability of APS to recover decommissioning costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including credit losses) in regulatory liabilities.

Coal Reclamation Escrow Account

APS has investments restricted for the future coal mine reclamation funding related to Four Corners. This escrow account is primarily invested in fixed income securities. Earnings and proceeds from sales of securities are reinvested in the escrow account. Because of the ability of APS to recover coal reclamation costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including credit losses) in regulatory liabilities. Activities relating to APS coal mine reclamation escrow account investments are included within the other special use funds in the table below.

Active Union Employee Medical Account

APS has investments restricted for paying active union employee medical costs. These investments may be used to pay active union employee medical costs incurred in the current and future periods. In 2024, APS was reimbursed $14 million for prior year active union employee medical claims from the active union employee medical account. The account is invested primarily in fixed income securities. In accordance with the ratemaking treatment, APS has deferred the unrealized gains and losses (including credit losses) in other regulatory assets. Activities relating to active union employee medical account investments are included within the other special use funds in the table below.

Captive Insurance Cell

Pinnacle West has investments held by the Captive that may be used to pay insurance losses in the event of certain insured loss events. The Captive may hold investment assets in cash, cash equivalents, and equity and fixed income instruments. These investments are restricted for insured loss events.

Pinnacle West consolidated investment holdings reflected in the tables below primarily relate to APS, with the exception of the Captive's investments included within other special use funds.

The following tables present the unrealized gains and losses based on the original cost of the investment and summarize the fair value of the nuclear decommissioning trusts and other special use fund assets (dollars in thousands):

	December 31, 2025					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 519,562	$ 62,573	$ 582,135		$ 433,044	$ (1)
Available for sale-fixed income securities	898,403	369,055	1,267,458	(a)	18,765	(14,993)
Other	(3,799)	3,199	(600)	(b)	—	—
Total	$ 1,414,166	$ 434,827	$ 1,848,993	(c)	$ 451,809	$ (14,994)

(a) As of December 31, 2025, the amortized cost basis of these available-for-sale investments is $1,265 million.
(b) Represents net pending securities sales and purchases.
(c) All amounts pertain to APS, with the exception of $40.3 million of other special use fund investments in equity securities and $3.2 million of unrealized gains relating to investments held by the Captive.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	December 31, 2024					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 435,470	$ 24,962	$ 460,432		$ 359,127	$ (176)
Available for sale-fixed income securities	844,040	355,544	1,199,584	(a)	7,717	(31,960)
Other	3,335	27,851	31,186	(b)	—	—
Total	$ 1,282,845	$ 408,357	$ 1,691,202	(c)	$ 366,844	$ (32,136)

(a) As of December 31, 2024, the amortized cost basis of these available-for-sale investments is $1,224 million.
(b) Represents net pending securities sales and purchases.
(c) All amounts pertain to APS, with the exception of $34.2 million of other special use fund investments in equity securities relating to investments held by the Captive.

The following table sets forth realized gains and losses relating to the sale and maturity of available-for-sale debt securities and equity securities, and the proceeds from the sale and maturity of these investment securities (dollars in thousands):

	Year Ended December 31,			
	Nuclear Decommissioning Trusts	Other Special Use Funds		Total
2025				
Realized gains	$ 12,826	$ 242		$ 13,068
Realized losses	$ (11,749)	$ —		$ (11,749)
Proceeds from the sale of securities (a)	$ 1,478,088	$ 377,112	(b)	$ 1,855,200
2024				
Realized gains	$ 75,690	$ 372		$ 76,062
Realized losses	$ (21,966)	$ —		$ (21,966)
Proceeds from the sale of securities (a)	$ 1,330,940	$ 355,154		$ 1,686,094
2023				
Realized gains	$ 111,922	$ 172		$ 112,094
Realized losses	$ (41,212)	$ (568)		$ (41,780)
Proceeds from the sale of securities (a)	$ 1,324,978	$ 354,744		$ 1,679,722

(a) Proceeds are reinvested in the nuclear decommissioning trusts and other special use funds, excluding amounts reimbursed to the Company for active union employee medical claims from the active union employee medical account.
(b) All amounts pertain to APS, with the exception of $51.4 million of other special use fund proceeds from the sale of securities relating to investments held by Captive.

Fixed Income Securities Contractual Maturities

The fair value fixed income securities summarized by contractual maturities as of December 31, 2025 is as follows (dollars in thousands):

	Nuclear Decommissioning Trusts	Coal Reclamation Escrow Account	Active Union Employee Medical Account	Total
Less than one year	$ 36,726	$ 87,421	$ 39,617	$ 163,764
1 year – 5 years	272,413	68,348	157,116	497,877
5 years – 10 years	173,131	—	16,553	189,684
Greater than 10 years	416,133	—	—	416,133
Total	$ 898,403	$ 155,769	$ 213,286	$ 1,267,458

19. Changes in Accumulated Other Comprehensive Loss

The following table shows the changes in Pinnacle West's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component (dollars in thousands):

	Pension and Other Postretirement Benefits		Derivative Instruments	Total
Balance at December 31, 2023	$ (34,754)		$ 1,610	$ (33,144)
Other comprehensive income/(loss) before reclassifications	1,039		(891)	148
Amounts reclassified from accumulated other comprehensive loss	2,054	(a)	—	2,054
Balance at December 31, 2024	(31,661)		719	(30,942)
Other comprehensive loss before reclassifications	(3,210)		(147)	(3,357)
Amounts reclassified from accumulated other comprehensive loss	1,891	(a)	—	1,891
Balance at December 31, 2025	$ (32,980)		$ 572	$ (32,408)

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 9.

The following table shows the changes in APS's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component (dollars in thousands):

	Pension and Other Postretirement Benefits	
Balance at December 31, 2023	$ (17,219)	
Other comprehensive income before reclassifications	1,255	
Amounts reclassified from accumulated other comprehensive loss	1,848	(a)
Balance at December 31, 2024	(14,116)	
Other comprehensive loss before reclassifications	(2,889)	
Amounts reclassified from accumulated other comprehensive loss	1,548	(a)
Balance at December 31, 2025	$ (15,457)	

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 9.

20. Leases

We lease certain land, buildings, vehicles, equipment, and other property through operating rental agreements with varying terms, provisions, and expiration dates. APS also has certain power purchase or PPAs and energy storage agreements that qualify as lease arrangements. Our leases have remaining terms that expire in 2026 through 2073. Substantially all of our leasing activities relate to APS.

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. The lessor trust entities have been deemed VIEs for which APS is the primary beneficiary. As the primary beneficiary, APS consolidated these lessor trust entities. The impacts from these sale leaseback transactions are excluded from our lease disclosures as lease accounting is eliminated upon consolidation. In September 2025, two of the three leased interests were purchased by APS. As of December 31, 2025, one VIE lease arrangement remains in effect. See Note 12 for discussion of VIEs and the 2025 acquisition of the VIE's noncontrolling interest.

APS is a party to PPAs that allow it the right to the generation capacity from certain natural-gas fueled generators during certain months of each year throughout the term of the arrangements. As APS only has rights to use the assets during certain periods of each year, the leases have non-consecutive periods of use. APS does not operate or maintain the leased assets. APS controls the dispatch of the leased assets during the months of use and is required to pay a fixed monthly capacity payment during these periods of use. For these types of leased assets, APS has elected to combine both the lease and non-lease payment components and accounts for the entire fixed payment as a lease obligation. In addition to the fixed monthly capacity payments, APS must also pay variable charges based on the actual production volume of the assets. The variable consideration is not included in the measurement of our lease obligation.

APS has executed various energy storage PPAs that allow APS the right to charge and discharge energy storage facilities. APS pays a fixed monthly capacity price for rights to use the lease assets. The agreements generally have 20-year lease terms and provide APS with the exclusive use of the energy storage assets through the lease term. APS does not operate or maintain the energy storage facilities and has no purchase options or residual value guarantees relating to these lease assets. For this class of energy storage lease assets, APS has elected to separate the lease and non-lease components. These leases are accounted for as operating leases, with lease terms that commenced between September 2023 and July 2025.

The following table provides information related to our lease costs (dollars in thousands):

	Year Ended December 31,		
	2025	2024	2023
Operating Lease Cost - PPAs and Energy Storage PPA Lease Contracts	$ 292,625	$ 147,313	$ 126,655
Operating Lease Cost - Land, Property, and Other Equipment	22,120	20,120	19,235
Total Operating Lease Cost	314,745	167,433	145,890
Variable Lease Cost (a)	124,707	144,108	135,007
Short-term Lease Cost	2,250	20,653	21,530
Total Lease Cost	$ 441,702	$ 332,194	$ 302,427

(a) Primarily relates to PPA lease contracts.

Lease costs are primarily included as a component of operating expenses on our Consolidated Statements of Income. Lease costs relating to PPAs and energy storage PPA lease contracts are recorded in fuel and purchased power on the Consolidated Statements of Income and are subject to recovery under the PSA or RES. See Note 8. The tables above reflect the lease cost amounts before the effect of regulatory deferral under the PSA and RES. Variable lease costs are recognized in the period the costs are incurred, and primarily relate to renewable PPA lease contracts. Payments under most renewable PPA lease contracts are dependent upon environmental factors, and due to the inherent uncertainty associated with the reliability of the fuel source, the payments are considered variable and are excluded from the measurement of lease liabilities and right-of-use lease assets. Certain of our lease agreements have lease terms with non-consecutive periods of use. For these agreements, we recognize lease costs during the periods of use. Leases with initial terms of 12 months or less are considered short-term leases and are not recorded on the balance sheets.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides information related to the maturity of our operating lease liabilities (dollars in thousands):

	December 31, 2025		
Year	PPAs and Energy Storage PPA Lease Contracts	Land, Property and Equipment Leases	Total
2026	$ 364,197	$ 21,141	$ 385,338
2027	390,260	18,858	409,118
2028	394,202	16,166	410,368
2029	398,287	14,033	412,320
2030	402,416	9,811	412,227
Thereafter	3,590,042	59,700	3,649,742
Total lease commitments	5,539,404	139,709	5,679,113
Less imputed interest	1,899,993	42,169	1,942,162
Total lease liabilities	$ 3,639,411	$ 97,540	$ 3,736,951

We recognize lease assets and liabilities upon lease commencement. As of December 31, 2025, we have various lease arrangements that have been executed, but have not yet commenced. We expect the total fixed consideration paid for these arrangements, which includes both lease and non-lease payments, will approximate $11.4 billion over the terms of the agreements. These arrangements primarily relate to energy storage PPA assets. We expect lease commencement dates ranging from April 2026 through June 2028, with lease terms expiring through June 2048. The lease commencement dates for certain arrangements have experienced delays. As a result of these delays and other events, APS has received cash proceeds from certain lessors prior to lease commencement. Proceeds received from lessors relating to energy storage PPA leases are accounted for as lease incentives on our Consolidated Balance Sheets, and upon lease commencement are amortized over the associated lease term. For regulatory purposes, the proceeds received by APS relating to these PPA leases are treated as a reduction to fuel and purchased power costs through the PSA in the period proceeds are received. See Note 8.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following tables provide other additional information related to operating lease liabilities (dollars in thousands):

	Year Ended December 31,								
	2025			2024			2023		
Cash paid for amounts included in the measurement of lease liabilities — operating cash flows:	$	226,484		$	143,950		$	123,472	
Right-of-use operating lease assets obtained in exchange for operating lease liabilities:	$	2,195,728	(a)	$	393,702	(b)		602,301	(c)

	December 31, 2025	December 31, 2024
Weighted average remaining lease term	15 years	11 years
Weighted average discount rate (d)	5.48 %	4.90 %

(a) Primarily relates to nine new energy storage PPA operating leases that commenced in 2025.
(b) Primarily relates to the three new energy storage operating lease agreements that commenced in 2024.
(c) Primarily relates to the two purchased power operating lease agreements that were modified in January 2023.
(d) Most of our lease agreements do not contain an implicit rate that is readily determinable. For these agreements we use our incremental borrowing rate to measure the present value of lease liabilities. We determine our incremental borrowing rate at lease commencement based on the rate of interest that we would have to pay to borrow, on a collateralized basis over a similar term, an amount equal to the lease payments in a similar economic environment. We use the implicit rate when it is readily determinable.

21. Asset Retirement Obligations

In 2025, the Company revised its cost estimates for existing AROs for the following:

- Cholla coal-fired power plant related to the closure of ponds and facilities, which resulted in an increase to the ARO of approximately $49 million, primarily due to increased cost estimates associated with the CCR Rule.
- Four Corners coal-fired power plant, which resulted in an increase of approximately $16 million.
- Navajo, a decommissioned coal-fired power plant, which resulted in a decrease of approximately $4 million.
- Ironwood, a solar power plant, recorded a new obligation of approximately $15 million.

APS has also recorded the initial investigation and assessment costs related to the newly signed EPA rule for legacy CCR surface impoundments and CCRMUs. At this time, APS is still evaluating the financial impacts of this final regulation on its business, with initial CCRMU site surveys due to be completed by February 2027 and final site investigation reports to be finalized by February 2028 in accordance with the rule published by EPA on February 10, 2026, extending the compliance deadlines. Based on the information available to APS at this time, APS cannot reasonably estimate the fair value of the entire CCRMU ARO. Depending on the outcome of those evaluations and site investigations, the costs associated with APS's management of CCR could materially increase, which could affect our financial condition, results of operations, or cash flows.

In 2024, the Company revised its cost estimates for existing ARO for the following:

- Cholla coal-fired power plant related to the closure of ponds and facilities, which resulted in an increase to the ARO of approximately $63 million, primarily due to cost estimates associated with the CCR Rule.
- Four Corners coal-fired power plant, which resulted in an increase of approximately $82 million, primarily due to cost estimates associated with the CCR Rule.
- Navajo, a decommissioned coal-fired power plant, which resulted in an increase of approximately $8 million.
- Palo Verde nuclear plant, which resulted in an increase of approximately $1 million.
- Solar, which resulted in a decrease to the ARO of approximately $11 million, primarily due to the reduced cost of solar panel disposal.

See additional details in Notes 8 and 14.

The following table shows the change in our ARO's (dollars in thousands):

	2025	2024
Asset retirement obligations at the beginning of year	$ 1,146,586	$ 966,001
Changes attributable to:		
Accretion expense	64,552	56,143
Settlements	(16,570)	(18,379)
Estimated cash flow revisions	61,080	142,821
Newly incurred obligation	14,651	—
Asset retirement obligations at the end of year	$ 1,270,299	$ 1,146,586

In accordance with regulatory accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal. See Note 8 for detail of regulatory liabilities.

22. Sale of Bright Canyon Energy

On August 4, 2023, Pinnacle West entered into an agreement pursuant to which we agreed to sell all of our equity interest in our wholly-owned subsidiary, BCE. The BCE Sale was accounted for as the sale of a business and was structured to close in multiple stages that were completed on January 12, 2024. Certain investments and assets that BCE previously held, including the TransCanyon joint venture and holdings in the two Tenaska wind farm investments, were not included in the BCE Sale and were instead transferred to PNW Power, a wholly-owned subsidiary of Pinnacle West. The BCE Sale did not include a $31 million equity bridge loan relating to BCE's Los Alamitos project, which was paid in full by Pinnacle West on August 4, 2023. Other than these retained investments and the debt instrument, all BCE assets and liabilities were included in the BCE Sale and were transferred to Ameresco.

The total carrying value of net assets transferred to Ameresco as a result of the BCE Sale was $79 million, with total consideration received by Pinnacle West of $108 million, resulting in a total pre-tax gain of $29 million, which was recognized between August 4, 2023 and January 12, 2024. The net assets transferred included $41 million of liabilities that have been assumed by Ameresco. The consideration received by Pinnacle West included both cash and interest-bearing promissory notes. The stages of the BCE Sale and timing of net assets transferring to Ameresco and related gain recognition are as follows:

- The first stage of the BCE Sale was completed on August 4, 2023. In the first stage, the net assets transferred to Ameresco totaled $44 million, which included a $36 million construction term loan. The assets and liabilities transferred in the first stage related to the BCE Los Alamitos project and were previously primarily classified as construction work in progress and current maturities of long-term debt, respectively. A gain of $6 million was recognized on our Consolidated Statements of Income for the year ended December 31, 2023 relating to the first stage of the BCE Sale.

- The final stage of the BCE Sale was completed on January 12, 2024. In the final stage, the net assets transferred to Ameresco totaled $35 million. The assets transferred in the final stage related primarily to equity method investments in the Kūpono Solar Project and other development stage projects. Our Consolidated Statements of Income for the year ended 2024, included a $23 million gain relating to the final stage of the BCE Sale.

As of January 12, 2024, all stages of the BCE Sale had been completed. As of December 31, 2024 the interest-bearing promissory note had been paid in full.

On January 30, 2024, Pinnacle West entered into a tax credit transfer agreement to purchase from Ameresco $23 million of investment tax credits from the BCE Los Alamitos project for $21 million.

Additionally, Pinnacle West continues to maintain certain guarantees relating to the Kūpono Solar Project sale-leaseback financing, which were not transferred in the BCE Sale transaction. See Note 14.

23. El Dorado Equity Investments

Equity Method Investments

El Dorado holds investments in equity securities accounted for under the equity method. The equity method of accounting is applied when we have the ability to exercise significant influence over the operating and financial policies of an investee. The equity method has been applied to El Dorado's equity investment holdings in SAI and AZ-VC.

SAI — SAI is a private corporation that manufactures electrical switchgear equipment used by data centers. El Dorado holds common stock in SAI and maintains a seat on SAI's board of directors.

AZ-VC — AZ-VC is a limited liability company fund focused on analyzing, investing, managing, and otherwise dealing with investments in privately-held early stage and emerging growth technology companies and businesses primarily based in Arizona, or based in other jurisdictions and having existing or potential strategic or economic ties to companies or other interests in Arizona. El Dorado holds Class A Membership interests in the fund.

These equity method investments are included in the other assets line item on Pinnacle West's Consolidated Balance Sheets. The following table presents El Dorado's ownership percentages and carrying value of investments accounted for under the equity method (dollars in millions):

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Investee	Pinnacle West Ownership Percentage as of December 31, 2025	December 31, 2025	December 31, 2024
SAI (a)	17 %	$ 21	$ —
AZ-VC (b)	24 %	15	11
Total equity method investments		$ 36	$ 11

(a) El Dorado has no further funding commitments to SAI.
(b) El Dorado has a $25.0 million funding commitment to AZ-VC, of which approximately $15.5 million has been funded as of December 31, 2025.

Our share of the investees' earnings or losses are recognized in other income and other expense on Pinnacle West's Consolidated Statements of Income. For the year ended December 31, 2025, the net equity method earnings relating to these investments was $29.0 million. For the year ended December 31, 2024, the net equity method earnings relating to these investments was $0.3 million.

Other Investments

El Dorado holds investments in other equity securities to which the equity method of accounting does not apply due to lack of significant influence over the investees' operating and financial policies. These equity investments do not have readily determinable fair values, and we have elected the measurement alternative for these investments. Investments accounted for under the measurement alternative are carried at cost adjusted for impairments or observable price changes. The Pinnacle West Consolidated Balance Sheets as of December 31, 2025 and December 31, 2024 include $25.1 million and $23.1 million, respectively, relating to these other El Dorado equity investments. These investments are carried at cost, as no impairments or observable price changes have occurred as of December 31, 2025.

PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(dollars in thousands)

	Year Ended December 31,		
	2025	**2024**	**2023**
Operating expenses	$ 9,667	$ 9,931	$ 11,249
Other			
Equity in earnings of subsidiaries	699,155	643,703	539,962
Other income (expense)	(1,917)	23,835	2,823
Total	697,238	667,538	542,785
Interest expense	90,233	65,261	47,251
Income before income taxes	597,338	592,346	484,285
Income tax benefit	(19,193)	(16,460)	(17,272)
Net income attributable to common shareholders	616,531	608,806	501,557
Other comprehensive income (loss) — attributable to common shareholders	(1,466)	2,202	(1,709)
Total comprehensive income — attributable to common shareholders	$ 615,065	$ 611,008	$ 499,848

See Combined Notes to Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED BALANCE SHEETS
(dollars in thousands)

	December 31,	
	2025	2024
ASSETS		
Current assets		
Cash and cash equivalents	$ 2,461	$ 23
Accounts receivable	162,006	163,203
Income tax receivable	7,856	6,673
Other current assets	848	434
Total current assets	173,171	170,333
Investments and other assets		
Investments in subsidiaries	9,020,104	8,435,150
Other assets	30,854	21,966
Total investments and other assets	9,050,958	8,457,116
TOTAL ASSETS	$ 9,224,129	$ 8,627,449
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 7,685	$ 3,471
Accrued taxes	10,013	4,799
Common dividends payable	110,022	106,592
Short-term borrowings	249,700	228,550
Current maturities of long-term debt	350,000	500,000
Operating lease liabilities	149	138
Other current liabilities	30,282	11,389
Total current liabilities	757,851	854,939
Long-term debt less current maturities	1,315,736	867,770
Deferred income taxes	43,167	24,536
Pension liabilities	2,744	4,462
Operating lease liabilities	1,044	1,194
Other	16,512	17,070
Total deferred credits and other	63,467	47,262
COMMITMENTS AND CONTINGENCIES		
Common stock equity		
Common stock	3,228,049	3,118,294
Accumulated other comprehensive loss	(32,408)	(30,942)
Retained earnings	3,850,817	3,666,959
Total Pinnacle West Shareholders' equity	7,046,458	6,754,311
Noncontrolling interests	40,617	103,167
Total Equity	7,087,075	6,857,478
TOTAL LIABILITIES AND EQUITY	$ 9,224,129	$ 8,627,449

See Combined Notes to Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF CASH FLOWS
(dollars in thousands)

	Year Ended December 31,		
	2025	2024	2023
Cash flows from operating activities			
Net income	$ 616,531	$ 608,806	$ 501,557
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of subsidiaries — net	(699,155)	(643,703)	(539,962)
Gain on sale relating to BCE	—	(22,988)	(6,423)
Depreciation and amortization	68	75	76
Deferred income taxes	18,675	40,231	(13,955)
Accounts receivable	(1,672)	15,268	(28,273)
Accounts payable	4,213	(4,869)	1,839
Accrued taxes and income tax receivables — net	4,030	(4,584)	9,505
Dividends received from subsidiaries	429,700	401,400	393,600
Other	30,457	22,959	(14,201)
Net cash provided by operating activities	402,847	412,595	303,763
Cash flows from investing activities			
Proceeds from sale relating to BCE	—	84,322	23,400
Investments in subsidiaries	(382,338)	(827,752)	(119,682)
Repayments of loans from subsidiaries and other	13,756	1,132	6,526
Advances of loans to subsidiaries	(10,202)	(11,336)	(59,349)
Net cash used for investing activities	(378,784)	(753,634)	(149,105)
Cash flows from financing activities			
Issuance of long-term debt	795,404	867,387	175,000
Repayment of long-term debt	(500,000)	(625,000)	—
Short-term borrowings and (repayments) — net	46,150	(48,100)	60,930
Short-term debt borrowings under term loan facility	175,000	200,000	—
Short-term debt repayments under term loan facility	(200,000)	—	—
Dividends paid on common stock	(422,792)	(394,663)	(386,486)
Common stock equity issuance and purchases — net	84,613	341,429	(4,093)
Net cash provided by (used for) financing activities	(21,625)	341,053	(154,649)
Net increase in cash and cash equivalents	2,438	14	9
Cash and cash equivalents at beginning of year	23	9	—
Cash and cash equivalents at end of year	$ 2,461	$ 23	$ 9

See Combined Notes to Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY
NOTES TO FINANCIAL STATEMENTS OF HOLDING COMPANY

The Combined Notes to Consolidated Financial Statements in Part II, Item 8 should be read in conjunction with the Pinnacle West Capital Corporation Holding Company Financial Statements.

The Pinnacle West Capital Corporation Holding Company Financial Statements have been prepared to present the financial position, results of operations and cash flows of Pinnacle West on a stand-alone basis as a holding company. Investments in subsidiaries are accounted for using the equity method. The noncontrolling interests relate to the Palo Verde sale leaseback VIE.

See Combined Notes to Consolidated Financial Statements.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Disclosure Controls and Procedures

The term “disclosure controls and procedures” means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Securities Exchange Act of 1934 (the “Exchange Act”) (15 U.S.C. 78a *et seq*.) is recorded, processed, summarized, and reported, within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to a company’s management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Pinnacle West’s management, with the participation of Pinnacle West’s Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of Pinnacle West’s disclosure controls and procedures as of December 31, 2025. Based on that evaluation, Pinnacle West’s Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, Pinnacle West’s disclosure controls and procedures were effective.

APS’s management, with the participation of APS’s Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of APS’s disclosure controls and procedures as of December 31, 2025. Based on that evaluation, APS’s Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, APS’s disclosure controls and procedures were effective.

(b) Management’s Annual Reports on Internal Control Over Financial Reporting

Reference is made to “Management’s Report on Internal Control over Financial Reporting (Pinnacle West Capital Corporation)” in Item 8 of this report and “Management’s Report on Internal Control over Financial Reporting (Arizona Public Service Company)” in Item 8 of this report.

(c) Attestation Reports of the Registered Public Accounting Firm

Reference is made to “Report of Independent Registered Public Accounting Firm” in Item 8 of this report and “Report of Independent Registered Public Accounting Firm” in Item 8 of this report on the internal control over financial reporting of Pinnacle West and APS, respectively.

(d) Changes In Internal Control Over Financial Reporting

No change in Pinnacle West’s or APS’s internal control over financial reporting occurred during the fiscal quarter ended December 31, 2025, that materially affected, or is reasonably likely to materially affect, Pinnacle West’s or APS’s internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Rule 10b5-1 Trading Plans

During the year ended December 31, 2025, none of our directors or executive officers adopted or terminated any contract, instruction or written plan for the purchase or sale of our securities to satisfy the affirmative defense conditions of Rule 10b5-1(c) or any "non-Rule 10b5-1 trading arrangement."

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Reference is hereby made to "Information About Our Board and Corporate Governance" and "Proposal 1 — Election of Directors" in the Pinnacle West Proxy Statement relating to the Annual Meeting of Shareholders to be held on May 14, 2026 (the "2026 Proxy Statement") and to the "Information about our Executive Officers" section in Part I of this report.

Pinnacle West has adopted a Code of Ethics for Financial Executives that applies to financial executives including Pinnacle West's Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer, Controller, Treasurer, and General Counsel, the President and Chief Operating Officer of APS and other persons designated as financial executives by the Chair of the Audit Committee. The Code of Ethics for Financial Executives is posted on Pinnacle West's website (*www.pinnaclewest.com)*. Pinnacle West intends to satisfy the requirements under Item 5.05 of Form 8-K regarding disclosure of amendments to, or waivers from, provisions of the Code of Ethics for Financial Executives by posting such information on Pinnacle West's website.

Pinnacle West has adopted an insider trading policy governing the purchase, sale, and/or other dispositions of its securities by directors, officers and employees, and Pinnacle West itself, that Pinnacle West believes are reasonably designed to promote compliance with insider trading laws, rules and regulations, and New York Stock Exchange listing standards. This policy is set forth in our Securities Trading Policy included as Exhibit 19.1 to this report.

ITEM 11. EXECUTIVE COMPENSATION

Reference is hereby made to "Director Compensation," "Executive Compensation," and "Human Resources Committee Interlocks and Insider Participation" in the 2026 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Reference is hereby made to "Ownership of Pinnacle West Stock" in the 2026 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth information as of December 31, 2025, with respect to the 2021 Plan, 2012 Plan, the 2007 Plan, under which our equity securities are outstanding or currently authorized for issuance.

Equity Compensation Plan Information

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	1,624,697	—	2,477,607
Equity compensation plans not approved by security holders	—	—	—
Total	1,624,697	—	2,477,607

(a) This amount includes shares subject to outstanding performance share awards and restricted stock unit awards at the maximum amount of shares issuable under such awards. However, payout of the performance share awards is contingent on the Company reaching certain levels of performance during a three-year performance period. If the performance criteria for these awards are not fully satisfied, the award recipient will receive less than the maximum number of shares available under these grants and may receive nothing from these grants.

(b) The weighted-average exercise price in this column does not take performance share awards or restricted stock unit awards into account, as those awards have no exercise price.

(c) Awards under the 2021 Plan, as amended, can take the form of options, stock appreciation rights, restricted stock, performance shares, performance share units, performance cash, stock grants, stock units, dividend equivalents, and restricted stock units. Additional shares cannot be awarded under the 2012 Plan, as amended, or the 2007 Plan. However, if an award under the 2012 Plan, as amended, or the 2007 Plan is forfeited, terminated or canceled or expires, the shares subject to such award, to the extent of the forfeiture, termination, cancellation, or expiration, may be added back to the shares available for issuance under the 2021 Plan.

Equity Compensation Plans Approved By Security Holders

Amounts in column (a) in the table above include shares subject to awards outstanding under three equity compensation plans that were previously approved by our shareholders: (a) the 2007 Plan, which was approved by our shareholders at our 2007 Annual Meeting of Shareholders, under which no new stock awards may be granted; (b) the 2012 Plan, which was approved by our shareholders at our 2012 Annual Meeting of Shareholders, as amended by the First Amendment to the 2012 Plan, which was approved by our shareholders at our 2017 Annual Meeting of Shareholders, under which no new stock awards may be granted; and (c) the 2021 Plan, which was approved by our shareholders at our 2021 Annual Meeting of Shareholders, as amended by the First Amendment to the 2021 Plan, which was approved by our shareholders at our 2023 Annual Meeting of Shareholders. See Note 10 of the Notes to Consolidated Financial Statements for additional information regarding these plans.

Equity Compensation Plans Not Approved by Security Holders

The Company does not have any equity compensation plans under which shares can be issued that have not been approved by the shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Reference is hereby made to "Information About Our Board and Corporate Governance" and "Related Party Transactions" in the 2026 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pinnacle West

Reference is hereby made to "Audit Matters — Audit Fees and — Pre-Approval Policies" in the 2026 Proxy Statement.

APS

The following fees were paid to APS's independent registered public accountants, Deloitte & Touche LLP, for the last two fiscal years:

Type of Service	2025	2024
Audit Fees (1)	$ 2,971,594	$ 2,967,862
Audit-Related Fees (2)	403,620	384,372
Tax Fees	—	—

(1) The aggregate fees billed for services rendered for the audit of annual financial statements and for review of financial statements included in Reports on Form 10-K and Form 10-Q, respectively.

(2) The aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of the financial statements and are not included in Audit Fees reported above, which primarily consist of fees for employee benefit plan audits in 2025 and 2024.

The Audit Committee pre-approves each audit service and non-audit service to be provided by Deloitte and Touche LLP for APS. The Audit Committee has delegated to the Chair of the Audit Committee the authority to pre-approve audit and non-audit services to be performed by the independent public accountants if the services are not expected to cost more than $100,000. The Chair must report any pre-approval decisions to the Audit Committee at its next scheduled meeting. All of the services performed by Deloitte & Touche LLP for APS in 2025 were pre-approved by the Audit Committee or the Chair consistent with the pre-approval policy.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Financial Statements and Financial Statement Schedules

See the Index to Financial Statements and Financial Statement Schedule in Part II, Item 8.

Exhibits Filed

The documents listed below are being filed or have previously been filed on behalf of Pinnacle West or APS and are incorporated herein by reference from the documents indicated and made a part hereof. Exhibits not identified as previously filed are filed herewith.

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
3.1	Pinnacle West	Articles of Incorporation, restated as of May 22, 2025	3.1 to Pinnacle West/APS June 30, 2025 Form 10-Q Report	8/6/2025
3.2	Pinnacle West	Pinnacle West Capital Corporation Bylaws, amended as of February 19, 2020	3.1 to Pinnacle West/APS February 25, 2020 Form 8-K Report	2/25/2020
3.3	APS	APS Articles of Incorporation, restated as of May 16, 2012	3.3 to Pinnacle West/APS June 30, 2025 Form 10-Q Report	8/6/1993
3.4	APS	APS Bylaws, amended as of December 16, 2008	3.4 to Pinnacle West/APS 2008 Form 10-K Report	2/20/2009
4.1	Pinnacle West	Specimen Certificate of Pinnacle West Capital Corporation Common Stock, no par value	4.1 to Pinnacle West June 20, 2017 Form 8-K Report	6/20/2017
4.2	Pinnacle West	Indenture dated as of December 1, 2000 between the Company and The Bank of New York, as Trustee, relating to Senior Unsecured Debt Securities	4.1 to Pinnacle West's Registration Statement No. 333-52476	12/21/2000
4.2(a)	Pinnacle West	Fifth Supplemental Indenture dated as of June 10, 2024	4.1 to Pinnacle West June 5, 2024 Form 8-K Report	6/10/2024
4.2(b)	Pinnacle West	Sixth Supplemental Indenture dated as of May 15, 2025	4.1 to Pinnacle West May 15, 2025 Form 8-K Report	5/15/2025
4.3	Pinnacle West APS	Indenture dated as of January 15, 1998 between APS and The Bank of New York Mellon Trust Company N.A. (successor to JPMorgan Chase Bank, N.A., formerly known as The Chase Manhattan Bank), as Trustee	4.10 to APS's Registration Statement Nos. 333-15379 and 333-27551 by means of APS January 13, 1998 Form 8-K Report	1/16/1998
4.3(a)	Pinnacle West APS	Seventh Supplemental Indenture dated as of May 1, 2003	4.1 to APS's Registration Statement No. 333-90824 by means of APS May 7, 2003 Form 8-K Report	5/9/2003
4.3(b)	Pinnacle West APS	Ninth Supplemental Indenture dated as of August 15, 2005	4.1 to APS's Registration Statements Nos. 333-106772 and 333-121512 by means of APS August 17, 2005 Form 8-K Report	8/22/2005
4.3(c)	APS	Tenth Supplemental Indenture dated as of August 1, 2006	4.1 to APS July 31, 2006 Form 8-K Report	8/3/2006

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
4.3(d)	Pinnacle West APS	Twelfth Supplemental Indenture dated as of August 25, 2011	4.6f to Pinnacle West/APS 2014 Form 10-K Report	2/20/2015
4.3(e)	Pinnacle West APS	Thirteenth Supplemental Indenture dated as of January 13, 2012	4.6g to Pinnacle West/APS 2014 Form 10-K Report	2/20/2015
4.3(f)	Pinnacle West APS	Fourteenth Supplemental Indenture dated as of January 10, 2014	4.6h to Pinnacle West/APS 2014 Form 10-K Report	2/20/2015
4.3(g)	Pinnacle West APS	Eighteenth Supplemental Indenture dated as of November 6, 2015	4.1 to Pinnacle West/APS November 3, 2015 Form 8-K Report	11/6/2015
4.3(h)	Pinnacle West APS	Nineteenth Supplemental Indenture dated as of May 6, 2016	4.1 to Pinnacle West/APS May 3, 2016 Form 8-K Report	5/6/2016
4.3(i)	Pinnacle West APS	Twentieth Supplemental Indenture dated as of September 20, 2016	4.1 to Pinnacle West/APS September 15, 2016 Form 8-K Report	9/20/2016
4.3(j)	Pinnacle West APS	Twenty-First Supplemental Indenture dated as of September 11, 2017	4.1 to Pinnacle West/APS September 11, 2017 Form 8-K Report	9/11/2017
4.3(k)	Pinnacle West APS	Twenty-Second Supplemental Indenture dated as of August 9, 2018	4.1 to Pinnacle West/APS August 9, 2018 Form 8-K Report	8/9/2018
4.3(l)	Pinnacle West APS	Twenty-Third Supplemental Indenture dated as of February 28, 2019	4.1 to Pinnacle West/APS February 28, 2019 Form 8-K Report	2/28/2019
4.3(m)	Pinnacle West APS	Twenty-Fourth Supplemental Indenture dated as of August 19, 2019	4.1 to Pinnacle West/APS August 16, 2019 Form 8-K Report	8/16/2019
4.3(n)	Pinnacle West APS	Twenty-Fifth Supplemental Indenture dated as of November 20, 2019	4.1 to Pinnacle West/APS November 20, 2019 Form 8-K Report	11/20/2019
4.3(o)	Pinnacle West APS	Twenty-Sixth Supplemental Indenture dated as of May 22, 2020	4.1 to Pinnacle West/APS May 22, 2020 Form 8-K Report	5/22/2020
4.3(p)	Pinnacle West APS	Twenty-Seventh Supplemental Indenture dated as of September 11, 2020	4.1 to Pinnacle West/APS September 11, 2020 Form 8-K Report	9/11/2020
4.3(q)	Pinnacle West APS	Twenty-Eighth Supplemental Indenture dated as of August 16, 2021	4.1 to Pinnacle West/APS August 16, 2021 Form 8-K Report	8/16/2021
4.3(r)	Pinnacle West APS	Twenty-Ninth Supplemental Indenture dated as of November 8, 2022	4.1 to Pinnacle West/APS November 8, 2022 Form 8-K Report	11/8/2022
4.3(s)	Pinnacle West APS	Thirtieth Supplemental Indenture dated as of June 30, 2023	4.1 to Pinnacle West/APS June 30, 2023 Form 8-K Report	6/30/2023
4.3(t)	Pinnacle West APS	Thirty-First Supplemental Indenture dated as of May 9, 2024	4.1 to Pinnacle West/APS May 9, 2024 Form 8-K Report	5/9/2024
4.3(u)	Pinnacle West APS	Thirty-Second Supplemental Indenture Dated as of August 15, 2025	4.2 to Pinnacle West/APS August 15, 2025 Form 8-K Report	8/15/2025
4.4	Pinnacle West	Third Amended and Restated Pinnacle West Capital Corporation Investors Advantage Plan dated as of November 25, 2008	4.1 to Pinnacle West's Form S-3 Registration Statement No. 333-155641	11/25/2008
4.5	Pinnacle West APS	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934		
4.6	Pinnacle West	Indenture, dated as of June 6, 2024, between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee	4.1 to Pinnacle West June 6, 2024 Form 8-K Report	6/6/2024

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
10.1	Pinnacle West APS	Two separate Decommissioning Trust Agreements (relating to PVGS Units 1 and 3, respectively), each dated July 1, 1991, between APS and Mellon Bank, N.A., as Decommissioning Trustee	10.2 to APS September 30, 1991 Form 10-Q Report	11/14/1991
10.1(a)	Pinnacle West APS	Amendment No. 1 to Decommissioning Trust Agreement (PVGS Unit 1), dated as of December 1, 1994	10.1 to APS 1994 Form 10-K Report	3/30/1995
10.1(b)	Pinnacle West APS	Amendment No. 1 to Decommissioning Trust Agreement (PVGS Unit 3), dated as of December 1, 1994	10.2 to APS 1994 Form 10-K Report	3/30/1995
10.1(c)	Pinnacle West APS	Amendment No. 2 to APS Decommissioning Trust Agreement (PVGS Unit 1) dated as of July 1, 1991	10.4 to APS 1996 Form 10-K Report	3/28/1997
10.1(d)	Pinnacle West APS	Amendment No. 2 to APS Decommissioning Trust Agreement (PVGS Unit 3) dated as of July 1, 1991	10.6 to APS 1996 Form 10-K Report	3/28/1997
10.1(e)	Pinnacle West APS	Amendment No. 3 to the Decommissioning Trust Agreement (PVGS Unit 1), dated as of March 18, 2002	10.2 to Pinnacle West March 31, 2002 Form 10-Q Report	5/15/2002
10.1(f)	Pinnacle West APS	Amendment No. 3 to the Decommissioning Trust Agreement (PVGS Unit 3), dated as of March 18, 2002	10.4 to Pinnacle West March 31, 2002 Form 10-Q Report	5/15/2002
10.1(g)	Pinnacle West APS	Amendment No. 4 to the Decommissioning Trust Agreement (PVGS Unit 1), dated as of December 19, 2003	10.3 to Pinnacle West 2003 Form 10-K Report	3/15/2004
10.1(h)	Pinnacle West APS	Amendment No. 4 to the Decommissioning Trust Agreement (PVGS Unit 3), dated as of December 19, 2003	10.5 to Pinnacle West 2003 Form 10-K Report	3/15/2004
10.1(i)	Pinnacle West APS	Amendment No. 5 to the Decommissioning Trust Agreement (PVGS Unit 1), dated as of May 1, 2007	10.1 to Pinnacle West/APS March 31, 2007 Form 10-Q Report	5/9/2007
10.1(j)	Pinnacle West APS	Amendment No. 5 to the Decommissioning Trust Agreement (PVGS Unit 3), dated as of May 1, 2007	10.2 to Pinnacle West/APS March 31, 2007 Form 10-Q Report	5/9/2007

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
10.2	Pinnacle West APS	Amended and Restated Decommissioning Trust Agreement (PVGS Unit 2) dated as of January 31, 1992, among APS, Mellon Bank, N.A., as Decommissioning Trustee, and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under two separate Trust Agreements, each with a separate Equity Participant, and as Lessor under two separate Facility Leases, each relating to an undivided interest in PVGS Unit 2	10.1 to Pinnacle West's 1991 Form 10-K Report	3/26/1992
10.2(a)	Pinnacle West APS	First Amendment to Amended and Restated Decommissioning Trust Agreement (PVGS Unit 2), dated as of November 1, 1992	10.2 to APS 1992 Form 10-K Report	3/30/1993
10.2(b)	Pinnacle West APS	Amendment No. 2 to Amended and Restated Decommissioning Trust Agreement (PVGS Unit 2), dated as of November 1, 1994	10.3 to APS 1994 Form 10-K Report	3/30/1995
10.2(c)	Pinnacle West APS	Amendment No. 3 to Amended and Restated Decommissioning Trust Agreement (PVGS Unit 2), dated as of June 20, 1996	10.1 to APS June 30, 1996 Form 10-Q Report	8/9/1996
10.2(d)	Pinnacle West APS	Amendment No. 4 to Amended and Restated Decommissioning Trust Agreement (PVGS Unit 2) dated as of December 16, 1996	APS 10.5 to APS 1996 Form 10-K Report	3/28/1997
10.2(e)	Pinnacle West APS	Amendment No. 5 to the Amended and Restated Decommissioning Trust Agreement (PVGS Unit 2), dated as of June 30, 2000	10.1 to Pinnacle West March 31, 2002 Form 10-Q Report	5/15/2002
10.2(f)	Pinnacle West APS	Amendment No. 6 to the Amended and Restated Decommissioning Trust Agreement (PVGS Unit 2), dated as of March 18, 2002	10.3 to Pinnacle West March 31, 2002 Form 10-Q Report	5/15/2002
10.2(g)	Pinnacle West APS	Amendment No. 7 to the Amended and Restated Decommissioning Trust Agreement (PVGS Unit 2), dated as of December 19, 2003	10.4 to Pinnacle West 2003 Form 10-K Report	3/15/2004
10.2(h)	Pinnacle West APS	Amendment No. 8 to the Amended and Restated Decommissioning Trust Agreement (PVGS Unit 2), dated as of April 1, 2007	10.1.2h to Pinnacle West 2007 Form 10-K Report	2/27/2008
10.3[a]	Pinnacle West APS	Arizona Public Service Company Directors' Deferred Compensation Plan, as restated, effective January 1, 1986	10.1 to APS June 30, 1986 Form 10-Q Report	8/13/1986
10.3(a)[a]	Pinnacle West APS	Second Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of January 1, 1993	10.2A to APS 1993 Form 10-K Report	3/30/1994

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
10.3(b)[a]	Pinnacle West APS	Third Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of May 1, 1993	10.1 to APS September 30, 1994 Form 10-Q Report	11/10/1994
10.3(c)[a]	Pinnacle West APS	Fourth Amendment to the Arizona Public Service Company Directors Deferred Compensation Plan, effective as of January 1, 1999	10.8A to Pinnacle West 1999 Form 10-K Report	3/30/2000
10.4[a]	Pinnacle West APS	Deferred Compensation Plan of 2005 for Employees of Pinnacle West Capital Corporation and Affiliates (as amended and restated effective January 1, 2016)	10.2.5 to Pinnacle West/APS 2015 Form 10-K Report	2/19/2016
10.5[a]	Pinnacle West APS	Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan of 2005 (as amended and restated effective January 1, 2016)	10.3.2 to Pinnacle West/APS 2015 Form 10-K Report	2/19/2016
10.5(a)[a]	Pinnacle West APS	First Amendment to the Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan of 2005 (as amended and restated effective January 1, 2016)	10.3.2a to Pinnacle West/APS 2016 Form 10-K Report	2/24/2017
10.5(b)[a]	Pinnacle West APS	Second Amendment to the Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan of 2005 (as amended and restated effective January 1, 2016)	10.3.2b to Pinnacle West/APS 2017 Form 10-K Report	2/23/2018
10.6[a]	Pinnacle West APS	Offer of Employment Letter dated May 19, 2022 between APS and Adam Heflin	10.4(8) to Pinnacle West/APS 2022 Form 10-K Report	2/27/2023
10.7[ab]	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.4 to Pinnacle West/APS June 30, 2021 Form 10-Q Report	8/5/2021
10.8[a]	Pinnacle West	Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	Appendix B to the Proxy Statement for Pinnacle West's 2007 Annual Meeting of Shareholders	4/20/2007
10.8(a)[a]	Pinnacle West	First Amendment to the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.2 to Pinnacle West/APS April 18, 2007 Form 8-K Report	4/20/2007
10.8(b)[ab]	Pinnacle West	Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan (Supplemental 2010 Award)	10.6 to Pinnacle West/APS March 31, 2011 Form 10-Q Report	4/29/2011
10.9[a]	Pinnacle West APS	Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	Appendix A to the Proxy Statement for Pinnacle West's 2012 Annual Meeting of Shareholders	3/29/2012
10.9(a)[a]	Pinnacle West	First Amendment to the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	Appendix A to the Proxy Statement for Pinnacle West's 2017 Annual Meeting of Shareholders	3/31/2017

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
10.10[a]	Pinnacle West	Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan (as amended by the First Amendment)	Appendix A to the Proxy Statement for Pinnacle West's 2022 Annual Meeting of Shareholders	5/19/2023
10.10(a)[ab]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan	10.6.5n to Pinnacle West/APS 2020 Form 10-K Report	2/25/2022
10.10(b)[ab]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan	10.6.5o to Pinnacle West/APS 2020 Form 10-K Report	2/25/2022
10.10(c)[ab]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan	10.6.5p to Pinnacle West/APS 2020 Form 10-K Report	2/25/2022
10.10(d)[ab]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan	10.6.5q to Pinnacle West/APS 2020 Form 10-K Report	2/25/2022
10.10(e)[ab]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan	10.6.5r to Pinnacle West/APS 2020 Form 10-K Report	2/25/2022
10.10(f)[ab]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan	10.6.5s to Pinnacle West/APS 2020 Form 10-K Report	2/25/2022
10.10(g)[ab]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan		
10.10(h)[ab]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan		
10.11[a]	Pinnacle West APS	Summary of 2026 Variable Incentive Plan and Officer Variable Incentive Plan		
10.12	Pinnacle West APS	Indenture of Lease with Navajo Tribe of Indians, Four Corners Plant	5.01 to APS's Form S-7 Registration Statement, File No. 2-59644	9/1/1977
10.12(a)	Pinnacle West APS	Supplemental and Additional Indenture of Lease, including amendments and supplements to original lease with Navajo Tribe of Indians, Four Corners Plant	5.02 to APS's Form S-7 Registration Statement, File No. 2-59644	9/1/1977
10.12(b)	Pinnacle West APS	Amendment and Supplement No. 1 to Supplemental and Additional Indenture of Lease Four Corners, dated April 25, 1985	10.36 to Pinnacle West's Registration Statement on Form 8-B Report, File No. 1-8962	7/25/1985
10.12(c)	Pinnacle West APS	Amendment and Supplement No. 2 to Supplemental and Additional Indenture of Lease with the Navajo Nation dated March 7, 2011	10.1 to Pinnacle West/APS March 31, 2011 Form 10-Q Report	4/29/2011

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
10.12(d)	Pinnacle West APS	Amendment and Supplement No. 3 to Supplemental and Additional Indenture of Lease with the Navajo Nation dated March 7, 2011	10.2 to Pinnacle West/APS March 31, 2011 Form 10-Q Report	4/29/2011
10.13	Pinnacle West APS	Application and Grant of multi-party rights-of-way and easements, Four Corners Plant Site	5.04 to APS's Form S-7 Registration Statement, File No. 2-59644	9/1/1977
10.13(a)	Pinnacle West APS	Application and Amendment No. 1 to Grant of multi-party rights-of-way and easements, Four Corners Site dated April 25, 1985	10.37 to Pinnacle West's Registration Statement on Form 8-B, File No. 1-8962	7/25/1985
10.14	Pinnacle West APS	Application and Grant of APS rights-of-way and easements, Four Corners Site	5.05 to APS's Form S-7 Registration Statement, File No. 2-59644	9/1/1977
10.14(a)	Pinnacle West APS	Application and Amendment No. 1 to Grant of APS rights-of-way and easements, Four Corners Site dated April 25, 1985	10.38 to Pinnacle West's Registration Statement on Form 8-B, File No. 1-8962	7/25/1985
10.15	Pinnacle West APS	Four Corners Project Co-Tenancy Agreement, conformed copy up through and including Amendment No. 13, dated June 25, 2021, among APS, Public Service Company of New Mexico, SRP, Tucson Electric Power Company and Navajo	10.5 to Pinnacle West/APS June 30, 2021 Form 10-Q Report	8/5/2021
10.15(a)	Pinnacle West APS	Four Corners Project Co-Tenancy Agreement, Amendment to Amendment No. 13, dated July 1, 2024, among APS, Public Service Company of New Mexico, SRP, Tucson Electric Power Company and Navajo		
10.16	Pinnacle West APS	Arizona Nuclear Power Project ("ANPP") Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles, and amendments 1-12 thereto	10.1 to APS 1988 Form 10-K Report	3/8/1989
10.16(a)	Pinnacle West APS	Amendment No. 13, dated as of April 22, 1991, to ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.1 to APS March 31, 1991 Form 10-Q Report	5/15/1991

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
10.16(b)	Pinnacle West APS	Amendment No. 14 to ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	99.1 to Pinnacle West June 30, 2000 Form 10-Q Report	8/14/2000
10.16(c)	Pinnacle West APS	Amendment No. 15, dated November 29, 2010, to ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.9.1c to Pinnacle West/APS 2010 Form 10-K Report	2/18/2011
10.16(d)	Pinnacle West APS	Amendment No. 16, dated April 28, 2014, to ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.2 to Pinnacle West/APS March 31, 2014 Form 10-Q Report	5/2/2014
10.17	Pinnacle West APS	Asset Purchase and Power Exchange Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990 and as of July 18, 1991	10.1 to APS June 30, 1991 Form 10-Q Report	8/8/1991
10.18	Pinnacle West APS	Long-Term Power Transaction Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990, and as of July 8, 1991	10.2 to APS June 30, 1991 Form 10-Q Report	8/8/1991
10.18(a)	Pinnacle West APS	Amendment No. 1 dated April 5, 1995 to the Long-Term Power Transaction Agreement and Asset Purchase and Power Exchange Agreement between PacifiCorp and APS	10.3 to APS 1995 Form 10-K Report	3/29/1996
10.19	Pinnacle West APS	Restated Transmission Agreement between PacifiCorp and APS dated April 5, 1995	10.4 to APS 1995 Form 10-K Report	3/29/1996
10.20	Pinnacle West APS	Reciprocal Transmission Service Agreement between APS and PacifiCorp dated as of March 2, 1994	10.6 to APS 1995 Form 10-K Report	3/29/1996
10.21	Pinnacle West	Third Amended and Restated Five-Year Credit Agreements dated as of February 18, 2026, among Pinnacle West, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto	10.1 to Pinnacle West/APS February 17, 2026 Form 8-K Report	2/19/2026

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
10.22	Pinnacle West APS	Amended and Restated Five-Year Credit Agreement dated as of February 18, 2026, among APS, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto	10.2 to Pinnacle West/APS February 17, 2026 Form 8-K Report	2/19/2026
10.23	Pinnacle West APS	Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	4.3 to APS Form 18 Registration Statement, File No. 33-9480	10/24/1986
10.23(a)	Pinnacle West APS	Amendment No. 1, dated as of November 1, 1986, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.5 to APS September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	12/4/1986
10.23(b)	Pinnacle West APS	Amendment No. 2 dated as of June 1, 1987 to Facility Lease dated as of August 1, 1986 between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS 1988 Form 10-K Report	3/8/1989
10.23(c)	Pinnacle West APS	Amendment No. 3, dated as of March 17, 1993, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS 1992 Form 10-K Report	3/30/1993
10.23(d)	Pinnacle West APS	Amendment No. 4, dated as of September 30, 2015, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under a Trust Agreement with Emerson Finance LLC, as Lessor, and APS, as Lessee	10.2 to Pinnacle West/APS September 30, 2015 Form 10-Q Report	10/30/2015
10.24	Pinnacle West APS	Agreement for the Transfer and Use of Wastewater and Effluent by and between APS, SRP and PWE dated June 1, 2001	10.103 to Pinnacle West/APS 2004 Form 10-K Report	3/16/2005
10.25	Pinnacle West APS	Agreement for the Sale and Purchase of Wastewater Effluent dated November 13, 2000, by and between the City of Tolleson, Arizona, APS and SRP	10.104 to Pinnacle West/APS 2004 Form 10-K Report	3/16/2005

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
10.26	Pinnacle West APS	Operating Agreement for the Co-Ownership of Wastewater Effluent dated November 16, 2000 by and between APS and SRP	10.105 to Pinnacle West/APS 2004 Form 10-K Report	3/16/2005
10.27	Pinnacle West APS	Municipal Effluent Purchase and Sale Agreement dated April 29, 2010, by and between City of Phoenix, City of Mesa, City of Tempe, City of Scottsdale, City of Glendale, APS and SRP	10.1 to Pinnacle West/APS March 31, 2010 Form 10-Q Report	5/6/2010
10.28	Pinnacle West APS	Contract, dated July 21, 1984, with DOE providing for the disposal of nuclear fuel and/or high-level radioactive waste, ANPP	10.31 to Pinnacle West's Form S-14 Registration Statement, File No. 2-96386	3/13/1985
10.29	Pinnacle West APS	Territorial Agreement between APS and SRP	10.1 to APS March 31, 1998 Form 10-Q Report	5/15/1998
10.30	Pinnacle West APS	Power Coordination Agreement between APS and SRP	10.2 to APS March 31, 1998 Form 10-Q Report	5/15/1998
10.31	Pinnacle West APS	Memorandum of Agreement between APS and SRP	10.3 to APS March 31, 1998 Form 10-Q Report	5/15/1998
10.31(a)	Pinnacle West APS	Addendum to Memorandum of Agreement between APS and SRP dated as of May 19, 1998	10.2 to APS May 19, 1998 Form 8-K Report	6/26/1998
10.32	Pinnacle West	Forward Sale Agreement, dated February 28, 2024, between Pinnacle West and Wells Fargo Bank, National Association	10.1 to Pinnacle West February 28, 2024 Form 8-K Report	3/4/2024
10.32(a)	Pinnacle West	Additional Forward Sale Agreement, dated February 28, 2024, between Pinnacle West and Wells Fargo Bank, National Association	10.2 to Pinnacle West February 28, 2024 Form 8-K Report	3/4/2024
10.32(b)	Pinnacle West	Amendment, dated as of August 28, 2025, to Forward Sale Agreement, dated February 28, 2024, and Additional Forward Sale Agreement, dated February 29, 2024, between the Company and Wells Fargo Bank, National Association	10.1 to Pinnacle West September 2, 2025 Form 8-K Report	9/2/2025
19.1	Pinnacle West	Securities Trading Policy of Pinnacle West	19.1 to Pinnacle West/APS 2024 Form 10-K Report	2/25/2025
21.1	Pinnacle West	Subsidiaries of Pinnacle West	21.1 to Pinnacle West/APS 2024 Form 10-K Report	2/25/2025
23.1	Pinnacle West	Consent of Deloitte & Touche LLP		
23.2	APS	Consent of Deloitte & Touche LLP		
31.1	Pinnacle West	Certificate of Theodore N. Geisler, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended		
31.2	Pinnacle West	Certificate of Andrew Cooper, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended		

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
31.3	APS	Certificate of Theodore N. Geisler, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended		
31.4	APS	Certificate of Andrew Cooper, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended		
32.1[c]	Pinnacle West	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		
32.2[c]	APS	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		
97	Pinnacle West	Policy Relating to Recovery of Erroneously Awarded Compensation	97 to Pinnacle West/APS 2023 Form 10-K Report	2/27/2024
99.1	Pinnacle West APS	Participation Agreement, dated as of August 1, 1986, among PVGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.1 to APS September 30, 1992 Form 10-Q Report	11/9/1992
99.1(a)	Pinnacle West APS	Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1, 1986, among PVGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	10.8 to APS September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	12/4/1986

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
99.1(b)	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of August 1, 1986, among PVGS Funding Corp., Inc., PVGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.4 to APS 1992 Form 10-K Report	3/30/1993
99.2	Pinnacle West APS	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to APS Form 18 Registration Statement, File No. 33-9480	10/24/1986
99.2(a)	Pinnacle West APS	Supplemental Indenture No. 1, dated as of November 1, 1986 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.6 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	12/4/1986
99.2(b)	Pinnacle West APS	Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Lease Indenture Trustee	4.4 to APS 1992 Form 10-K Report	3/30/1993
99.3	Pinnacle West APS	Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.3 to APS Form 18 Registration Statement, File No. 33-9480	10/24/1986
99.3(a)	Pinnacle West APS	Amendment No. 1, dated as of November 1, 1986, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.10 to APS September 30, 1986 Form 10-Q Report by means of Amendment No. l on December 3, 1986 Form 8	12/4/1986

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
99.3(b)	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.6 to APS 1992 Form 10-K Report	3/30/1993
99.4	Pinnacle West APS	Indemnity Agreement dated as of March 17, 1993 by APS	28.3 to APS 1992 Form 10-K Report	3/30/1993
101.SCH	Pinnacle West APS	Inline XBRL Taxonomy Extension Schema Document		
101.CAL	Pinnacle West APS	Inline XBRL Taxonomy Extension Calculation Linkbase Document		
101.LAB	Pinnacle West APS	Inline XBRL Taxonomy Extension Label Linkbase Document		
101.PRE	Pinnacle West APS	Inline XBRL Taxonomy Extension Presentation Linkbase Document		
101.DEF	Pinnacle West APS	Inline XBRL Taxonomy Definition Linkbase Document		
104	Pinnacle West APS	The Cover Page Interactive Data File (formatted as Inline iXBRL and contained in Exhibit 101)		

(a) Management contract or compensatory plan or arrangement to be filed as an exhibit pursuant to Item 15(b) of Form 10-K.

(b) Additional agreements, substantially identical in all material respects to this Exhibit, have been entered into with additional persons. Although such additional documents may differ in other respects (such as dollar amounts and dates of execution), there are no material details in which such agreements differ from this exhibit.

(c) Furnished herewith.

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.

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Date: February 25, 2026

/s/ Theodore N. Geisler

(Theodore N. Geisler, Chairman of the Board of Directors, President and Chief Executive Officer)

Power of Attorney

We, the undersigned directors and executive officers of Pinnacle West Capital Corporation, hereby severally appoint Andrew Cooper and Shirley A. Baum, and each of them, our true and lawful attorneys with full power to them and each of them to sign for us, and in our names in the capacities indicated below, any and all amendments to this Annual Report on Form 10-K filed with the Securities and Exchange Commission.

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
/s/ Theodore N. Geisler (Theodore N. Geisler, Chairman of the Board of Directors, President and Chief Executive Officer)	Principal Executive Officer and Director	February 25, 2026
/s/ Andrew Cooper (Andrew Cooper, Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 25, 2026
/s/ Elizabeth A. Blankenship (Elizabeth A. Blankenship, Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 25, 2026

/s/ Glynis A. Bryan (Glynis A. Bryan)	Director	February 25, 2026
/s/ Ronald Butler, Jr. (Ronald Butler, Jr.)	Director	February 25, 2026
/s/ Gonzalo A. de la Melena, Jr. (Gonzalo A. de la Melena, Jr.)	Director	February 25, 2026
/s/ Carol S. Eicher (Carol S. Eicher)	Director	February 25, 2026
/s/ Susan T. Flanagan (Susan T. Flanagan)	Director	February 25, 2026
/s/ Richard P. Fox (Richard P. Fox)	Director	February 25, 2026
/s/ Paula J. Sims (Paula J. Sims)	Director	February 25, 2026
/s/ William H. Spence (William H. Spence)	Director	February 25, 2026
/s/ Kristine L. Svinicki (Kristine L. Svinicki)	Director	February 25, 2026
/s/ James E Trevathan, Jr. (James E. Trevathan, Jr.)	Director	February 25, 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.

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Date: February 25, 2026

/s/ Theodore N. Geisler
(Theodore N. Geisler, Chairman of the Board of Directors, President and Chief Executive Officer)

Power of Attorney

We, the undersigned directors and executive officers of Arizona Public Service Company, hereby severally appoint Andrew Cooper and Shirley A. Baum, and each of them, our true and lawful attorneys with full power to them and each of them to sign for us, and in our names in the capacities indicated below, any and all amendments to this Annual Report on Form 10-K filed with the Securities and Exchange Commission.

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
/s/ Theodore N. Geisler (Theodore N. Geisler, Chairman of the Board of Directors, President and Chief Executive Officer)	Principal Executive Officer and Director	February 25, 2026
/s/ Andrew Cooper (Andrew Cooper, Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 25, 2026
/s/ Elizabeth A. Blankenship (Elizabeth A. Blankenship Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 25, 2026

/s/ Glynis A. Bryan (Glynis A. Bryan)	Director	February 25, 2026
/s/ Ronald Butler, Jr. (Ronald Butler, Jr.)	Director	February 25, 2026
/s/ Gonzalo A. de la Melena, Jr. (Gonzalo A. de la Melena, Jr.)	Director	February 25, 2026
/s/ Carol S. Eicher (Carol S. Eicher)	Director	February 25, 2026
/s/ Susan T. Flanagan (Susan T. Flanagan)	Director	February 25, 2026
/s/ Richard P. Fox (Richard P. Fox)	Director	February 25, 2026
/s/ Paula J. Sims (Paula J. Sims)	Director	February 25, 2026
/s/ William H. Spence (William H. Spence)	Director	February 25, 2026
/s/ Kristine L. Svinicki (Kristine L. Svinicki)	Director	February 25, 2026
/s/ James E Trevathan, Jr. (James E. Trevathan, Jr.)	Director	February 25, 2026