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, 2024

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 Each Registrant as specified in its charter; State of Incorporation; Address; and Telephone Number	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	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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post 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.

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 Exchange 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	$	8,663,553,568	as of June 30, 2024
ARIZONA PUBLIC SERVICE COMPANY	$	0	as of June 30, 2024

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 20, 2025:	119,099,064
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of February 20, 2025:	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 21, 2025 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 that General Instruction.

TABLE OF CONTENTS

		Page
GLOSSARY OF NAMES AND TECHNICAL TERMS		ii
FORWARD-LOOKING STATEMENTS		1
PART I		3
Item 1.	Business	3
Item 1A.	Risk Factors	33
Item 1B.	Unresolved Staff Comments	48
Item 1C.	Cybersecurity	48
Item 2.	Properties	50
Item 3.	Legal Proceedings	52
Item 4.	Mine Safety Disclosures	52
Information about our Executive Officers		53
PART II		55
Item 5.	Market for Registrants' Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	55
Item 6.	[Reserved]	56
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	57
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	88
Item 8.	Financial Statements and Supplementary Data	89
	Pinnacle West Financial Statements	95
	APS Financial Statements	106
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	202
Item 9A.	Controls and Procedures	202
Item 9B.	Other Information	203
Item 9C.	Disclosure Regarding Foreign Jurisdictions that Prevent Inspections	203
PART III		203
Item 10.	Directors, Executive Officers and Corporate Governance of Pinnacle West	203
Item 11.	Executive Compensation	203
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	203
Item 13.	Certain Relationships and Related Transactions, and Director Independence	205
Item 14.	Principal Accountant Fees and Services	205
PART IV		206
Item 15.	Exhibits and Financial Statement Schedules	206
Item 16.	Form 10-K Summary	227
SIGNATURES		228

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. Item 8 also includes Combined Notes to Consolidated Financial Statements.

GLOSSARY OF NAMES AND TECHNICAL TERMS

AC	Alternating Current
ACC	Arizona Corporation Commission
ADEQ	Arizona Department of Environmental Quality
AFUDC	Allowance for Funds Used During Construction
ANPP	Arizona Nuclear Power Project, also known as Palo Verde
APS	Arizona Public Service Company, a subsidiary of the Company
ARO	Asset retirement obligations
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
CAISO	California Independent System Operator
Captive	Captive Insurance Cell
CCR	Coal combustion residuals
Cholla	Cholla Power Plant
DG	Distributed Generation
DOE	United States Department of Energy
DOI	United States Department of the Interior
DSM	Demand side management
EES	Energy Efficiency Standard
EGU	Electric generating unit
El Dorado	El Dorado Investment Company, a subsidiary of the Company
EPA	United States Environmental Protection Agency
FERC	United States Federal Energy Regulatory Commission
Four Corners	Four Corners Power Plant
GHG	Greenhouse gas
GWh	Gigawatt-hour, one billion watts per hour
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
Native Load	Retail and wholesale sales supplied under traditional cost-based rate regulation
Navajo Plant	Navajo Generating Station
NERC	North American Electric Reliability Corporation
NRC	United States Nuclear Regulatory Commission
NTEC	Navajo Transitional Energy Company, LLC
OCI	Other comprehensive income
Palo Verde	Palo Verde Generating Station or PVGS
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
Redhawk	Redhawk Power Plant
RES	Arizona Renewable Energy Standard and Tariff
Salt River Project or SRP	Salt River Project Agricultural Improvement and Power District
SCE	Southern California Edison Company
Sundance	Sundance Power Plant
TCA	Transmission cost adjustor
TEAM	Tax expense adjustor mechanism
VIE	Variable interest entity

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 Item 1A and in 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:

- uncertainties associated with the current and future economic environment, including economic growth rates, labor market conditions, inflation, supply chain delays, increased expenses, volatile capital markets, or other unpredictable effects;
- current and future economic conditions in Arizona, such as the housing market and overall business and regulatory environment;
- our ability to manage capital expenditures and operations and maintenance costs while maintaining reliability and customer service levels;
- 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;
- 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), the effects of energy conservation measures and DG, and technological advancements;
- 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;
- power plant and transmission system performance and outages;
- competition in retail and wholesale power markets;
- regulatory and judicial decisions, developments, and proceedings;
- new legislation, ballot initiatives, and regulation or interpretations of existing legislation or regulations, including those relating to environmental requirements, regulatory and energy policy, nuclear plant operations, and potential deregulation of retail electric markets;
- fuel and water supply availability;
- our ability to achieve timely and adequate rate recovery of our costs through our rates and adjustor recovery mechanisms, including returns on and of debt and equity capital investment;
- the ability of APS to meet renewable energy and energy efficiency mandates and recover related costs;
- the ability of APS to achieve its clean energy goals (including a goal by 2050 of 100% clean, carbon-free electricity) and, if these goals are achieved, the impact of such achievement on APS, its customers, and its business, financial condition, and results of operations;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- the development of new technologies which may affect electric sales or delivery, including as a result of delays in the development and application of new technologies;
- 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;
- environmental, economic, and other concerns surrounding coal-fired generation, including regulation of GHG;
- volatile fuel and purchased power costs;
- the investment performance of the assets of our nuclear decommissioning trust, captive insurance cell, pension, and other postretirement benefit plans, and the resulting impact on future funding requirements;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;

- potential shortfalls in insurance coverage;
- new accounting requirements or new interpretations of existing requirements;
- generation, transmission, and distribution facilities and system conditions and operating costs;
- our ability to meet the anticipated future need for additional generation and associated transmission facilities in our region;
- the willingness or ability of counterparties, power plant participants, and power plant landowners to meet contractual or other obligations or extend the rights for continued power plant operations; and
- restrictions on dividends or other provisions in our credit agreements and ACC orders.

These and other factors are discussed in the Risk Factors described in Item 1A of this report, and in 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 a holding company incorporated in Arizona that conducts business through its subsidiaries. We derive essentially all of our revenues and earnings from our wholly-owned subsidiary, APS. APS is incorporated in Arizona and is a vertically-integrated electric utility that provides either retail or wholesale electric service to most 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.

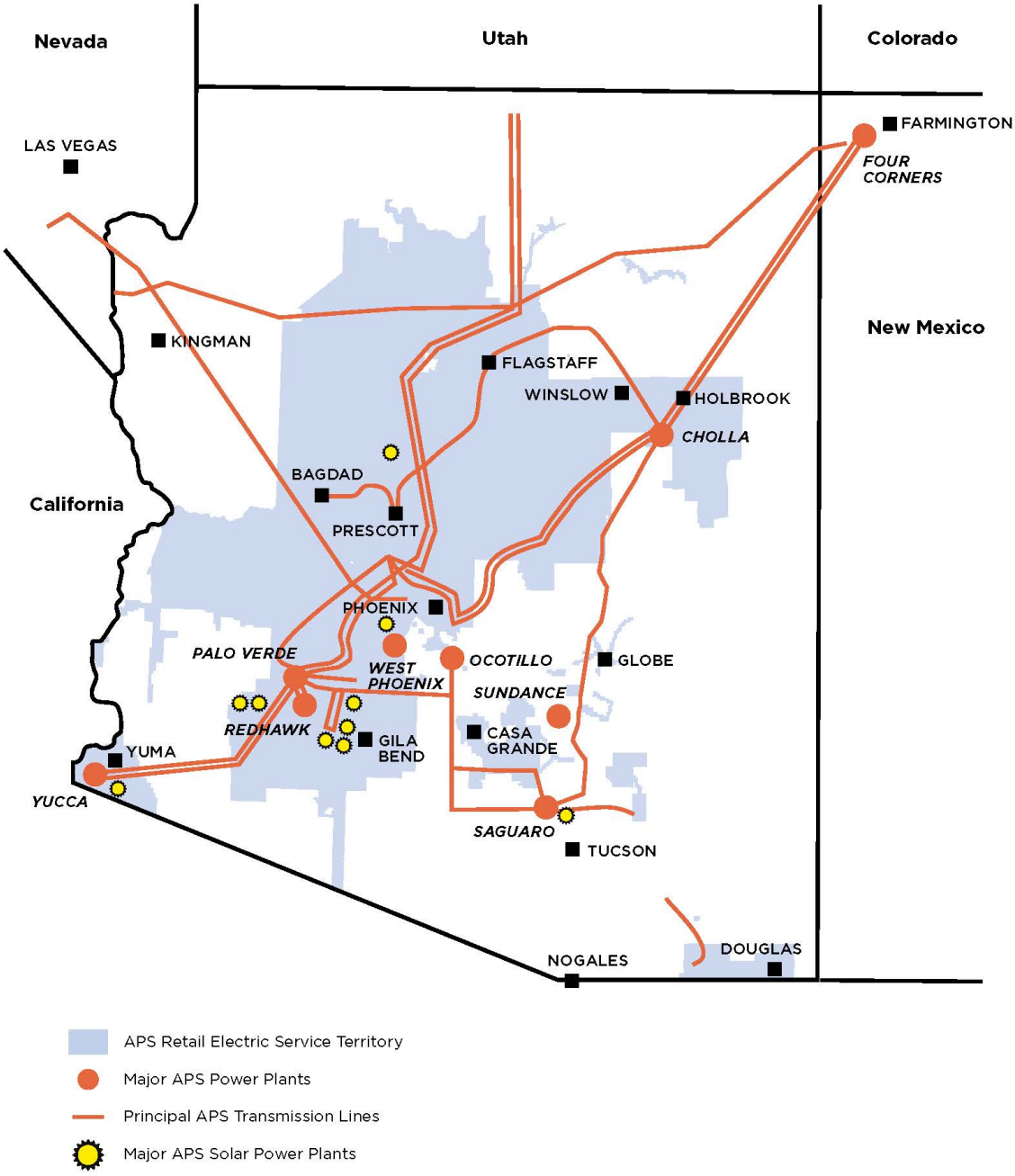
Pinnacle West's other active subsidiaries are El Dorado, an Arizona corporation, and PNW Power, a Delaware limited liability company. BCE was a subsidiary of Pinnacle West, but was sold in January 2024. Additional information related to these subsidiaries is provided later in this report.

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 6,540 MW of regulated generation capacity and we hold a mix of both long-term and short-term purchased power agreements for additional capacity. During 2024, no single purchaser or user of energy accounted for more than 1.4% of our electric revenues.

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



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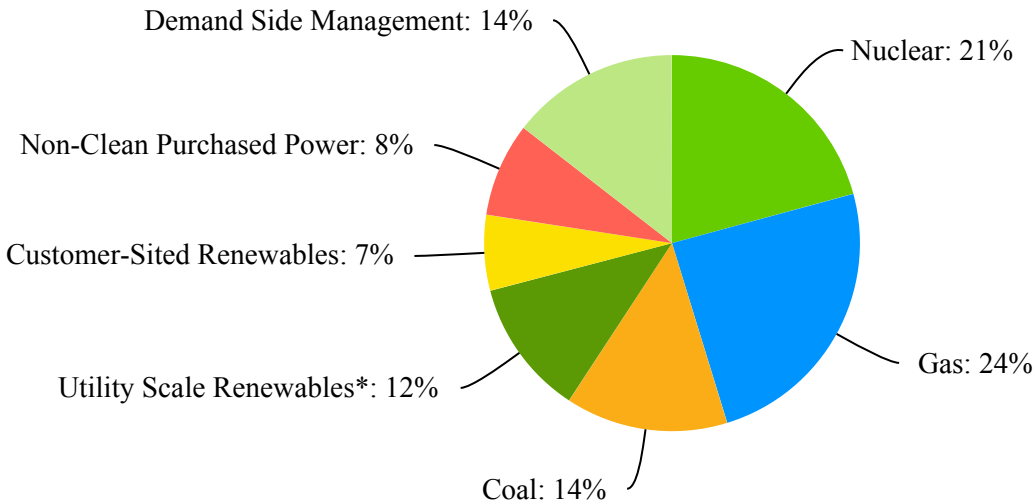
Energy Sources and Resource Planning

To serve its customers, APS obtains power through its various generation stations and through purchased power agreements. 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 2024 were approximately as follows:



*Utility Scale Renewables include energy from biogas, biomass, geothermal, solar, and wind.

The share of APS's energy supply being derived from clean resources was approximately 54% in 2024, which includes energy from nuclear, renewables and DSM.

Clean Energy Focus Initiatives

In response to climate change, APS has undertaken a number of initiatives to reduce carbon, including renewable energy procurement and development, and promotion of programs and rates that promote energy conservation, renewable energy use, and energy efficiency. See "Energy Sources and Resource Planning — Current and Future Resources" below for details of these plans and initiatives. APS currently has a diverse portfolio of renewable resources, including biogas, biomass, geothermal, solar, and wind. In addition, in January 2020, APS announced its Clean Energy Commitment, a three-pronged approach aimed at ultimately eliminating carbon-emitting resources from its electric generation resource portfolio.

APS's Clean Energy Commitment consists of three parts:

- A 2050 goal to provide 100% clean, carbon-free electricity;
- A 2030 target to achieve a resource mix that is 65% clean energy, with 45% of the generation portfolio coming from renewable energy; and
- A plan to exit from coal-fired generation by 2031.

Among other strategies, APS intends to achieve these goals through various methods such as relying on Palo Verde, one of the nation's largest producers of carbon-free energy; increasing clean energy resources, including renewables; developing energy storage; exiting from coal-generated electricity; managing demand with a modern interactive grid; promoting customer technology and energy efficiency; and optimizing regional resources. Management takes into consideration climate change and other environmental risks in its strategy development, business planning, and enterprise risk management processes. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information about APS's Clean Energy Commitment.

Over this same period of time, APS also intends to harden its infrastructure in order to improve climate resiliency, which involves system and operational improvements aimed at reducing the impact of extreme weather events and other climate-related disruptions upon APS's operations. Among other resiliency strategies, APS anticipates increasing investments in a modern and more flexible electricity grid with advanced distribution technologies. APS plans to continue its forest management programs aimed at reducing wildfires, as those risks become compounded by shorter, drier winters and longer, hotter summers as a result of climate change.

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 the EPA under the EPA GHG Reporting Program. In addition to reporting to the EPA, we publicly report Scope 1 and 2, as well as a limited number of Scope 3, GHG emissions. This data is then communicated to the public in Pinnacle West's annual Corporate Responsibility Report as performance data and in CDP Reports, which are available on our website (*www.pinnaclewest.com/corporate-responsibility*). The reports provide information related to the Company and its approach to sustainability and its workplace and environmental performance. The information on Pinnacle West's website, including Corporate Responsibility Reports and CDP Reports, is not incorporated by reference into or otherwise a part of this report.

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 17% of Unit 2. In addition, APS leases approximately 12.1% 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. The leaseback was originally scheduled to expire at the end of 2015 and contained options to renew the leases or to purchase the leased property for fair market value at the end of the lease terms. On July 7, 2014, APS exercised the fixed rate lease renewal options. The exercise of the renewal options originally resulted in APS retaining the assets through 2023 under one lease and 2033 under the other two leases. On April 1, 2021, APS executed an amendment relating to the lease agreement with the term ending in 2023. The amendment extends the lease term for this lease through 2033 and changes the lease payment. As a result of this amendment, APS will now retain the assets through 2033 under all three lease agreements. At the end of the lease renewal periods, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors. See Note 17 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 52% 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 has recovered costs for ten claims pursuant to the terms of the August 15, 2014 settlement agreement, for ten separate time periods during July 1, 2011 through October 31, 2023. The DOE has approved and paid approximately $156.7 million for these claims (APS's share is approximately $45.6 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 2017 Rate Case Decision, this regulatory liability is being refunded to customers. See Note 3. On October 31, 2024, APS filed its eleventh claim pursuant to the terms of the August 15, 2014, settlement agreement in the amount of approximately $18 million (APS's share is approximately $5.3 million). In February 2025, the DOE approved approximately $17.6 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. On August 8, 2016, the D.C. Circuit denied a petition for rehearing.

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 10 for a discussion of the insurance maintained by the Palo Verde participants, including APS, for Palo Verde.

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 3,573 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 are expected to be in service in 2026, and the addition of eight combustion turbines (approximately 397 MW total) at Redhawk, which are expected to be in service in 2028.

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. APS plans to exit coal-fired generation as part of its portfolio of electricity generating resources, including Four Corners, by 2031.

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 has 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 has committed to end the use of coal at its remaining Cholla units during 2025.

APS purchased all of Cholla coal requirements from a coal supplier that mines the coal under long-term leases of coal reserves with the federal and state governments and private landholders. APS elected not to extend the coal and transportation agreements that expired on December 31, 2024, as Cholla operations are expected to conclude in 2025.

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 is leased from the Navajo Nation and is also subject to an easement from the federal government.

The co-owners of the Navajo Plant and the Navajo Nation agreed that the Navajo Plant would remain in operation until December 2019 under the existing plant lease. 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 over its previously estimated life through 2026. APS will seek continued recovery in rates for the book value of its remaining investment in the plant. See Note 3 for details related to the resulting regulatory asset plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and which may be material.

See Note 10 for information regarding APS's coal mine reclamation obligations related to these coal-fired plants.

Solar Facilities

APS developed utility scale solar resources through the 180 MW ACC-approved AZ Sun Program, investing approximately $675 million in this program. These facilities are owned by APS and are located in multiple locations throughout Arizona. In addition to the AZ Sun Program, APS developed the 44 MW Red Rock Solar Plant and the 150 MW Agave Solar Plant, each of which it owns and operates, and has contracted for the construction of the 168 MW Ironwood Solar Plant.

APS owns and operates more than thirty small solar systems around the state. Together they have the capacity to produce approximately 4 MW of renewable energy. This fleet of solar systems includes a 3 MW facility located at the Prescott Airport and 1 MW of small solar systems in various locations across Arizona. APS has also developed solar photovoltaic DG systems installed as part of the Community Power Project in Flagstaff, Arizona. The Community Power Project, approved by the ACC on April 1, 2010, was a pilot program through which APS owns, operates, and receives energy from approximately 1 MW of solar photovoltaic DG systems located within a certain test area in Flagstaff, Arizona. The pilot program is now complete and as part of the 2017 Rate Case Decision, the participants have been transferred to the Solar Partner Program described below. Additionally, APS owns 13 MW of solar photovoltaic systems installed across Arizona through the ACC-approved Schools and Government Program.

In December 2014, the ACC voted that it had no objection to APS implementing an APS-owned rooftop solar research and development program aimed at learning how to efficiently enable the integration of rooftop solar and battery storage with the grid. The first stage of the program, called the "Solar Partner Program," placed 8 MW of residential rooftop solar on strategically selected distribution feeders in an effort to maximize potential system benefits, as well as made systems available to limited-income customers who could not easily install solar through transactions with third parties. The second stage of the program, which included an additional 2 MW of rooftop solar and energy storage, placed two energy storage systems sized at 2 MW on two different high solar penetration feeders to test various grid-related operation improvements and system interoperability, and was in operation by the end of 2016. The costs for this program have been included in APS's rate base as part of the 2017 Rate Case Decision.

In the 2017 Rate Case Decision, the ACC also approved the "APS Solar Communities" program. APS Solar Communities (formerly AZ Sun II) is a three-year program authorizing APS to spend $10

million to $15 million in capital costs each year to install utility-owned DG systems on low to moderate income residential homes, non-profit entities, Title I schools, and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES. Currently, APS has installed 14 MW of DG systems under the APS Solar Communities program. In the 2019 Rate Case decision, the ACC authorized APS to spend $20 million to $30 million in capital costs for the APS Solar Communities program each year for a period of three years from the effective date of the decision. Subsequently, on March 5, 2024, the ACC ordered APS not to expand or extend the APS Solar Communities program. Consistent with that decision, the Solar Communities program has been discontinued and APS stopped enrolling new customers. APS will continue work on projects that were enrolled prior to that decision.

Renewable Energy Portfolio

To date, APS has a diverse portfolio of existing and planned renewable resources totaling 7,660 MW, including biogas, biomass, geothermal, solar, and wind. Of this portfolio, 3,608 MW are currently in operation and 4,052 MW are under contract for development or are under construction. Renewable resources in operation include 416 MW of facilities owned by APS, 1,465 MW of long-term purchased power agreements, and an estimated 1,727 MW of customer-sited, third-party owned distributed energy resources.

On June 30, 2023, APS issued an ASRFP (the "2023 ASRFP") pursuant to which APS procured nearly 7,300 MW of new resources to be in service from 2026 to 2028.

On November 20, 2024, APS issued an ASRFP (the "2024 ASRFP") seeking 2,000 MW of resources. APS is seeking projects that can reach commercial operation beginning June 1, 2028 through June 1, 2030 but will consider projects that may achieve commercial operation as early as 2026. Additionally, APS is interested in projects that require longer planning, permitting, and construction and can be commercially operational after June 1, 2030. Bids for the 2024 ASRFP were due on February 5, 2025.

APS's strategy to achieve its RES requirements includes executing purchased power contracts for new facilities, ongoing development of distributed energy resources and procurement of new facilities to be owned by APS. See "Energy Sources and Resource Planning — Generation Facilities — Solar Facilities" above for information regarding APS-owned solar facilities and "Energy Sources and Resource Planning — Generation Facilities — Energy Storage" below for more information regarding APS-owned energy storage facilities.

The following table summarizes APS's renewable energy sources 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.

	Location	Actual/ Target Commercial Operation Date	Term (Years)	Net Capacity In Operation (MW AC)	Net Capacity Planned/ Under Development (MW AC)
APS Owned					
Solar:					
AZ Sun Program:					
Paloma	**Gila Bend, AZ**	**2011**		**17**	

Cotton Center	**Gila Bend, AZ**	**2011**		**17**	
Hyder Phase 1	**Hyder, AZ**	**2011**		**11**	
Hyder Phase 2	**Hyder, AZ**	**2012**		**6**	
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**	
Subtotal AZ Sun Program				**180**	—
Multiple Facilities	**AZ**	**Various**		**4**	
Red Rock	**Red Rock, AZ**	**2016**		**44**	
Agave Solar	**Arlington, AZ**	**2023**		**150**	
Ironwood Solar	**Dateland, AZ**	**2026**			**168**
Distributed Energy:					
APS Owned (a)	**AZ**	**Various**		**38**	
Total APS Owned				**416**	**168**
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 and 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				**1,465**	**3,821**
Distributed Energy					
Solar (b)					
Third-party Owned	**AZ**	**Various**		**1,694**	**63**
Agreement 1	**Bagdad, AZ**	**2011**	**25**	**15**	
Agreement 2	**AZ**	**2011-2012**	**20-21**	**18**	
Total Distributed Energy				**1,727**	**63**
Total Renewable Portfolio				**3,608**	**4,052**

(a) Includes Flagstaff Community Power Project, APS School and Government Program, APS Solar Partner Program, and APS Solar Communities Program.

(b) Includes rooftop solar facilities owned by third parties. DG is produced in direct current and is converted to alternating current for reporting purposes.

Energy Storage

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.

See "Item 7 — Management's Discussion and Analysis of Financial Condition — Clean Energy Commitment — Energy Storage" for a table summarizing the resources in APS's energy storage portfolio that are 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.

Purchased Power Contracts

In addition to its own available generating capacity, APS purchases electricity under various arrangements, including long-term contracts and purchases through short-term markets to supplement its owned or leased generation and hedge its energy requirements. A portion of APS's purchased power expense is netted against wholesale sales on the Consolidated Statements of Income. See Note 15. APS continually assesses its need for additional capacity resources to assure system reliability. In addition, APS has also entered into several PPAs for energy storage. See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Energy Storage" above for details on our energy storage PPAs.

Purchased Power Capacity — APS's purchased power capacity under long-term contracts as of the date of this report is summarized in the table below. All capacity values are based on net capacity unless otherwise noted.

Type	Dates Available	Capacity (MW)
Purchase Agreement (a)	Year-round through June 14, 2025	46
Demand Response Agreement	Summer seasons through 2025	75
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, 2020-2026	565
Extension Term	May 1 through October 31, 2026-2031	565
Tolling Agreement	June 1 through September 30, 2020-2026	570
Extension Term	May 1 through October 31, 2027-2034	600
Renewable Energy (b)	Various	1,465

(a) Up to 46 MW of capacity is available; however, the amount of electricity available to APS under this agreement is based in large part on customer demand and is adjusted annually.

(b) Does not include MW of capacity planned or under development. See "Energy Sources and Resource Planning — Generation Facilities — Renewable Energy Portfolio" for more details on renewable energy power purchase agreements.

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 2024 peak one-hour demand on its electric system was recorded on August 4, 2024, at 8,210 MW, compared to the 2023 peak of 8,162 MW recorded on July 15, 2023. APS's reserve margin at the time of the 2024 peak demand, calculated using system load serving capacity, was 15%. For 2025, APS is procuring market resources to maintain its minimum 16% planning reserve criteria.

Future Resources and Resource Plan

ACC rules require utilities to develop 15-year Integrated Resource Plans ("IRP") 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 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 to November 1. 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 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.

See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Clean Energy Focus Initiatives" and "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Energy Storage" above for information regarding future plans for energy storage.

See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Generation Facilities — Coal-Fueled Generating Facilities" above for information regarding plans for Cholla, Four Corners and the Navajo Plant.

Western Energy Imbalance Market and Wholesale Market

In 2016, APS began to participate in the Western Energy Imbalance Market ("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 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 Southwest Power Pool ("SPP"). The Markets+ tariff was filed with FERC on March 29, 2024 and was approved on January 16, 2025. APS announced a market decision to pursue participation in SPP Markets+. In addition, APS is participating in the Western Resource Adequacy Program administered by Western Power Pool and is transitioning to full binding participation as early as summer 2027. These regional efforts are driven by the objectives of reducing customer cost and improving reliability.

Energy Modernization Plan

In June 2021, the ACC adopted clean energy rules based on a series of ACC amendments to the final energy rules. The adopted rules require 100% clean energy by 2070 and the following interim standards for carbon reduction from a baseline carbon emissions level: 50% reduction by December 31, 2032; 65% reduction by December 31, 2040; 80% reduction by December 31, 2050, and 95% reduction by December 31, 2060. Since the adopted clean energy rules differed substantially from the original Recommended Opinion and Order ("ROO"), supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source request for proposals ("ASRFP") requirements and the IRP process. During the August 2022 ACC Open Meeting, the ACC voted to postpone a decision on the ASRFP and IRP rulemaking package until 2023. On May 26, 2023, the ACC opened a new docket to review articles within the Arizona Administrative Code related to Resource Planning, the Renewable Energy Standard and Tariff, and Electric Energy Efficiency Standards. On January 9, 2024, the ACC approved a rulemaking process to begin on this matter. During the ACC Open Meeting on February 6, 2024, the ACC approved motions to direct ACC Staff to include recommendations to repeal the current Electric Energy Efficiency and Renewable Energy Standard rules during the rulemaking process. On August 21, 2024, ACC Staff proposed amendments striking the rules and filed preliminary economic, small business, and consumer impact statements, consistent with the formal rulemaking process. APS cannot predict the outcome of this matter. See Note 3 for additional information related to these energy rules.

Renewable Energy Standard

In 2006, the ACC approved the RES. 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.

In June 2021, the ACC adopted a clean energy rules package which would require APS to meet certain clean energy standards and technology procurement mandates, obtain approval for its action plan included in its IRP, and seek cost recovery in a rate process. Since the adopted clean energy rules differed substantially from the original ROO, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider ASRFP requirements and the IRP process. See "Energy Modernization Plan" above for more information.

On July 1, 2021, APS filed its 2022 RES Implementation Plan and proposed a budget of approximately $93.1 million. APS filed an amended 2022 RES Implementation Plan on December 9, 2021, with a proposed budget of $100.5 million. This budget included funding for programs to comply with the decision in the 2019 Rate Case, including the ACC authorizing spending $20 million to $30 million in capital costs for the continuation of the APS Solar Communities program each year for a period of three years from the effective date of 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 2022. On May 18, 2022, the ACC approved the 2022 RES Implementation Plan, including an amendment requiring a stakeholder working group convene to develop a community solar program for the ACC's consideration at a future date.

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 2022. 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. 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 2023. The ACC has not yet ruled on the 2024 RES Implementation Plan. APS cannot predict the outcome of this proceeding.

On July 1, 2024, APS filed its 2025 RES Implementation Plan and proposed a budget of approximately $92.7 million. 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 2024. The ACC has not yet ruled on the 2025 RES Implementation Plan. APS cannot predict the outcome of this proceeding.

On June 14, 2021, APS filed an application for approval of its Green Power Partners Program ("GPP"). On September 1, 2021, the ACC approved the application. On June 28, 2024, APS filed an application for approval of modifications to the GPP and requested a renewable generation renewable energy credits waiver. The ACC has not yet ruled on the GPP application. APS cannot predict the outcome of this proceeding.

Demand Side Management

On January 1, 2011, Arizona regulators adopted an EES of 22% cumulative annual energy savings by 2020 to increase energy efficiency and other DSM programs encouraging customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. APS achieved the 22% EES in 2021. See Note 3 for information regarding energy efficiency, other DSM obligations and the Energy Modernization Plan.

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 3 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.

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC's retail electric competition rules. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACC's retail electric competition rules. During a July 15, 2020, ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. In April 2022, the Arizona Legislature passed, and the Governor signed a bill that repealed the electric deregulation law that had been in place in Arizona since 1998. On August 27, 2024, the ACC administratively closed this docket due to inactivity and obsolescence.

Wholesale

FERC regulates rates for wholesale power sales and transmission services. See Note 3 for information regarding APS's transmission rates. During 2024, approximately 4.2% 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 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 five critical transmission projects that comprise the APS strategic transmission portfolio, which represents a significant upgrade to APS's transmission system. These five projects, along with other projects included in the Ten-Year Transmission Plan, 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 is expected to issue regulations for these bills in 2025. Pinnacle West and APS are currently reviewing whether they 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 the EPA on June 19, 2019, and replaced by the Affordable Clean Energy ("ACE") regulations, which were a far narrower set of rules. While the U.S. Court of Appeals for the D.C. Circuit subsequently vacated the ACE 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 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.

As such, for new natural gas-fired combustion turbine power plants, EPA is proposing that carbon emission performance standards apply based on the annual capacity factors. For the highest utilization combustion turbines, EPA is therefore proposing that such facilities be retrofitted for carbon capture and sequestration or utilization controls ("CCS") by 2032. For intermediate or low-load natural gas fired combustion turbines, those with 40% or less capacity factors, EPA's regulations would not require add-on pollution controls. Instead, natural gas-fired combustion turbines with capacity factors of up to 20% would be effectively unregulated, while such turbines with capacity factors over 20% and up to 40% would be subject to carbon dioxide emission rate limitations. EPA did not finalize standards for existing natural gas-

fired combustion turbines but has indicated that it will propose a new set of standards, initiating a separate rulemaking, for these existing gas-fired power plants within the next year.

For coal-fired power plants, instead of imposing regulations based on capacity and utilization, EPA has finalized subcategories based on planned retirement dates. This means that 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. We cannot predict the outcome of the litigation challenging EPA's latest carbon emission standards for power plants. In addition, the Trump administration has stated that it intends to reverse or substantially revise these standards. 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.

If this regulation remains in effect, it will 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 carbon capture and sequestration and achieve 90% capture efficiency may not be feasible. Future resource plans and procurement efforts implicating the development of such new generation remains pending and, as such, at this time APS is not able to quantify the financial impact associated with EPA's GHG regulations for power plants.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standards ("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.

EPA Environmental Regulation

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, 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 recent 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 ("WIIN") 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. At this time, the Arizona Department of Environmental Quality ("ADEQ") has taken steps to develop a CCR permitting program. It remains unclear when the EPA would approve the permitting program pursuant to the WIIN 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.

- With respect to APS's Cholla facility, APS's application for alternative closure was submitted to EPA on November 30, 2020. While EPA has deemed APS's application administratively "complete," the Agency's approval remains pending. If granted, this application would allow the continued disposal of CCR within Cholla's existing unlined CCR surface impoundments until the required date for ceasing coal-fired boiler operations in April 2025. This application will be subject to public comment and, potentially, judicial review. We expect to have a proposed decision from EPA regarding Cholla in 2025.

We cannot at this time predict the outcome of these regulatory proceedings or when the 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 CCR management units ("CCRMUs"), which contain at least 1,000 tons of CCR, broadly encompass any location at an operating coal-fired power plant where CCR 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. At this time, APS is still evaluating the impacts of this final regulation on its business, with initial CCRMU site surveys due to be completed by February 2026 and final site investigation reports to be finalized by February 2027. Based on the information available to APS at this time, APS cannot reasonably estimate the fair value of the entire CCRMU asset retirement obligation. 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.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. The Navajo Plant disposed of CCR only in a dry landfill storage area. 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 subject to alternative closure). 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. 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 effluent limitation guidelines ("ELG") on October 13, 2020, and based off those guidelines, APS completed a National Pollutant Discharge Elimination System ("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. Nonetheless, 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.

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 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 EGU fleet is located were designated as in attainment. At this time, because proposed SIPs and FIPs implementing the revised ozone NAAQSs have yet to be released, APS is unable to predict what impact the adoption of these standards may have on APS. APS will continue to monitor these standards as they are implemented within the jurisdictions affecting APS.

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 National Ambient Air Quality Standards ("NAAQS"). Thermal power plant emission limitations are a key aspect of these regulations, which involve emission allowance trading for nitrogen oxide ("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. As such, while EPA may elect to resume work on and finalize this proposal in the future, it is unlikely to do so over a near-term horizon. APS cannot predict the outcome of any future EPA efforts to add Arizona to the federal Good Neighbor Plan (which depends on action disapproving the Arizona State Implementation Plan) or whether the Good Neighbor Plan itself will remain in effect pending the outcome of judicial review in the D.C. Circuit Court of Appeals. Should 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 April 25, 2024, EPA finalized revisions to the existing MATS regulations governing emissions of toxic air pollution from existing coal-fired power plants. The final regulations increase the stringency of filterable particulate matter limits used to demonstrate compliance with MATS and require the use of continuous emissions monitoring systems to ensure compliance (as opposed to periodic performance testing). These final regulations will take effect for existing coal-fired power plants, such as Four Corners, within three years of publication in the Federal Register. Based on APS's assessment of the revised MATS regulations, this final rule is unlikely to have a material impact on plant operations or require significant capital expenditures to ensure compliance.

Superfund-Related Matters. The Comprehensive Environmental Response Compensation and Liability Act ("Superfund" or "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. APS's estimated costs related to this investigation and study is approximately $3 million. APS anticipates incurring additional expenditures in the future, but

because the final costs associated with remediation requirements set forth in the RI/FS are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

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 ("RID"). 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 per-and polyfluoroalkyl ("PFAS") compounds 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 ("SIBW") Superfund site. The SIBW 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 SIBW 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 ("EAB") took up review of the Four Corners NPDES Permit. The EAB denied the environmental group petition on September 30, 2020. While on January 22, 2021, the environmental groups filed a petition for review of the EAB'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 requires investigation of thermal wastewater discharges from Four Corners, administratively closes the litigation filed in January of 2021, and APS does not expect the outcome to have a material impact on its financial condition, results of operations, or cash flows.

Water Supply

Based on a declaration from the U.S. Bureau of Reclamation, as of January 1, 2025, Arizona's supply of Colorado River water will remain subject to a Tier 1 shortage. This is the third 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. In addition, APS is a party to a water contract that allows the Company to secure water for Four Corners in the event of a water shortage in the San Juan River Basin.

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, that 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 below table presents the employee count as of December 31, 2024:

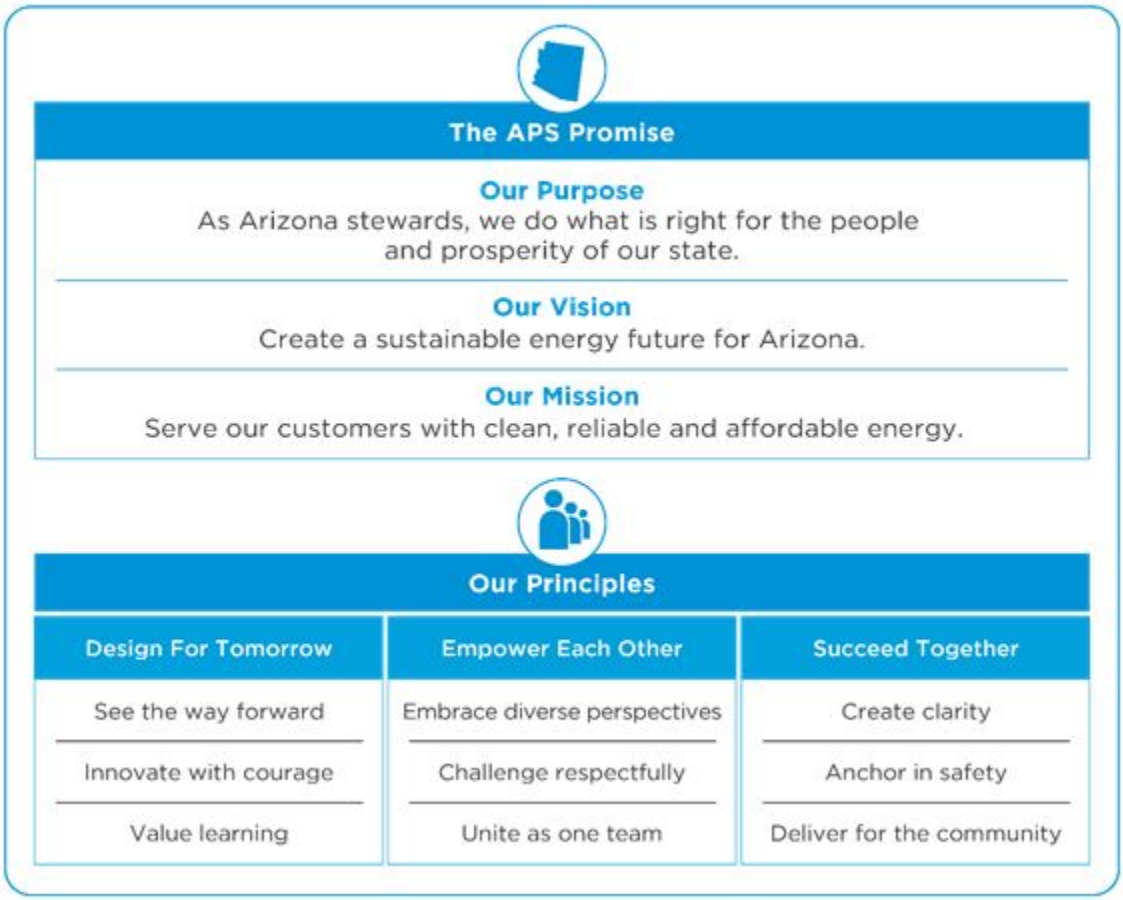
	Principal Executive Office Address	Year of Formation	Approximate Number of Employees at December 31, 2024	
Pinnacle West	400 North Fifth Street Phoenix, AZ 85004	1985	88	
APS	400 North Fifth Street P.O. Box 53999 Phoenix, AZ 85072-3999	1920	6,315	(a)
El Dorado	400 North Fifth Street Phoenix, AZ 85004	1983	—	
PNW Power	400 North Fifth Street Phoenix, AZ 85004	2023	—	
Total			6,403	

(a) Includes employees at jointly-owned generating facilities (approximately 2,300 employees) for which APS serves as the generating facility manager.

Approximately 1,180 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. Collective bargaining relating to these employees is ongoing.

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. The APS Promise continues to be reinforced and integrated throughout our Company programs and messaging.



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 2024, we had 80% participation in these surveys, and our Employee Experience Index was 87%. 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 is 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;
- Executive listening sessions to provide employees with opportunities to be heard; and
- An optional self-paced module available to all employees that explains how cultural competence drives inclusion.

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, including leadership academies, rotational programs, mentoring, industry certifications, and loaned executive programs. In 2024, we ran dedicated programs for individual contributors, new leaders, and high potential managers. We also launched an enterprise-wide on-demand learning platform to support a modern learning culture, with over 2,220 active users, encompassing engagement from every business unit and 5,650 hours of learning in 2024.
- *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. We partner closely with educational institutions and organizations to build a talent-ready pool for these critical roles.
- *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:* Palo Verde expanded its internship programs in 2024 to include nuclear operations, further strengthening our talent pipeline for the critically important licensed and non-licensed operators.

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. 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 among our most valuable assets, 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 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

On August 4, 2023, Pinnacle West entered into a purchase and sale agreement pursuant to which we agreed to sell all of our equity interest in our wholly-owned subsidiary BCE to Ameresco (the "BCE Sale"). The transaction was accounted for as the sale of a business and closed in multiple stages. The final closing of the BCE Sale was completed on January 12, 2024. See Note 20 for additional details. 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 Delaware limited liability corporation and a wholly-owned subsidiary of Pinnacle West.

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 venture partners' utility affiliates. The U.S. DOE's Grid Deployment Office selected TransCanyon to enter into capacity contract negotiations for up to 25% of the Cross-Tie 500-kilovolt transmission line ("Cross-Tie") as part of the Transmission Facilitation Program. The agreement was executed on June 12, 2024. The proposed Cross-Tie project 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.

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 power purchase agreements ("PPAs"). PNW Power indirectly owns 9.9% of Clear Creek and 5.1% of Nobles 2.

El Dorado

El Dorado is an Arizona corporation and a wholly-owned subsidiary of Pinnacle West. 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 holds the following:

- $25 million investment in the Energy Impact Partners fund, of which approximately $18.8 million has been funded as of December 31, 2024. 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 (formerly invisionAZ Fund), of which approximately $11.8 million has been funded as of December 31, 2024. 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 $1.2 million has been funded as of December 31, 2024. Westly Seed Fund is focused on supporting entrepreneurs involved in the energy, mobility, building, and industrial sectors.

- Equity investment in SAI Advanced Power Solutions ("SAI"), a private corporation that manufactures electrical switchgear equipment used by data centers. El Dorado accounts for this investment under the equity method, with a December 31, 2024 investment carrying value of zero. SAI has seen an increased demand for their customized switchgear products. El Dorado has no funding commitments to SAI.

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 Securities and Exchange Commission ("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 10.

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, and orders of agencies that regulate APS's business, including FERC, NRC, EPA, the ACC, and state and local governmental agencies. These 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.

Environmental Clean Up. APS has been named as a PRP for Superfund sites in Phoenix, Arizona, and it could be named a PRP in the future for other environmental clean-up at sites identified by a regulatory body. APS cannot predict with certainty the amount and timing of all future expenditures related to environmental matters because of the difficulty of estimating clean-up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all PRPs.

Coal Ash. In December 2014, the EPA issued final regulations governing the handling and disposal of CCR, which are generated as a result of burning coal and consist of, among other things, fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste. APS disposes of CCR in ash ponds and dry storage areas. To the extent the rule requires the closure or modification of these CCR units, modification or changes to the manner of closure of such units, or the construction of new CCR units beyond what we currently anticipate, APS would incur significant additional costs for CCR disposal. In addition, the rule may also require corrective action to address releases from CCR disposal units or the presence of CCR constituents within groundwater near CCR disposal units above certain regulatory thresholds.

Ozone National Ambient Air Quality Standards. In 2015, the EPA finalized revisions to the NAAQS for ozone, which set new, more stringent standards on emissions of nitrogen oxide, a precursor to ozone, in an effort to protect human health and human welfare. Depending on the final attainment designations for the new standards and the state implementation requirements, APS may be required to invest in new pollution control technologies and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas. In addition, the EPA may in the future further increase the stringency of various NAAQS, including for ozone or other pollutants, such as particulate matter. With regard to even more stringent NAAQS requirements, additional control measures and compliance costs may become necessary for APS as well as its current and potential future customers.

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.

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 CO_2, which is a major byproduct of the combustion of fossil fuel, and other GHG emissions.

Potential Financial Risks — Greenhouse Gas Regulation, the Clean Power Plan and Potential Litigation. On April 25, 2024, the 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. Additionally, the Trump administration has stated that it intends to reverse or substantially revise these standards. See Item 1 - Environmental Matters - Climate Change 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 3 for a discussion of the Navajo Plant and Cholla retirement and the related risks associated with APS's continued recovery of its remaining investment in the plant.

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

In November 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC's retail electric competition rules. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12,

2020, ACC Staff issued its second report regarding possible modifications to the ACC's retail electric competition rules. During a July 15, 2020, ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. The ACC continues to discuss matters related to retail electric competition, including the potential for additional buy-through programs or other pilot programs. In April 2022, the Arizona Legislature passed, and the Governor signed, a bill that repealed the electric deregulation law that had been in place in Arizona since 1998. On August 27, 2024, the ACC administratively closed this docket due to inactivity and obsolescence. Modification of the ACC's retail electric competition rules or other efforts of deregulation could result in 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 in energy efficiency and conservation programs and other demand-side management 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 requested a waiver of this requirement in the 2024 and 2025 RES Implementation Plans, which have not yet been approved by the ACC). 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. APS's actual sales growth, excluding weather-related variations, may differ from its projections as a result of numerous factors, such as economic conditions, customer growth, the legal, regulatory, and business environment in Arizona, usage patterns and energy conservation, slower than expected ramp-up of and/or fewer than expected data centers and large 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 $24 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 $6 million.

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 now receiving unprecedented incremental requests for service from extra-large commercial energy users (over 25 MW) with very high energy demands that persist virtually around-the-clock. These incremental requests for service by extra-large energy users far exceed available generation and transmission resource capacity in the Southwest region for the foreseeable future. APS is exploring available options for securing sufficient electric generation and transmission to meet these projections of future customer needs; however, there are difficulties in properly forecasting the demands of these extra-large customers due to factors such as the nascent nature of the industries (e.g., artificial intelligence) that these customers are supporting and the multiple variables that impact their usage ramp-up and ultimate level of demand. As data center and other extra-large customer opportunities evolve and develop, we may also enter into arrangements with customers and potential customers that require us to invest capital and assume credit risk related to such developments and the related generation and transmission investments before we receive any potential return. APS is implementing strategies to attempt to reduce this risk; however, 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 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 seasons, 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 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, governmental 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 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 inability to successfully develop, acquire or operate generation resources 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. The current regulatory standards, laws, and regulations create strategic challenges as to the appropriate generation portfolio and fuel diversification mix. In addition, 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. The development and operation of any generation facility is also subject to many risks, including those related to financing, siting, permitting, new and evolving technology, extreme weather events, workforce issues, cybersecurity attacks, supply

chain constraints for critical spare parts, and the construction of sufficient transmission capacity to support these facilities among others. APS needs to develop or acquire new generation 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 January 2020, APS announced its goal to provide 100% clean, carbon-free electricity by 2050 with an intermediate 2030 target of achieving a resource mix that is 65% clean energy, with 45% of the generation portfolio coming from renewable energy. APS's ability to successfully execute its clean energy commitment 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 also projected to exacerbate such drought conditions. In addition, Colorado River water supplies for Arizona are subject to a Tier 1 shortage declaration, which substantially limits the quantity of water available for the state. 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 cybersecurity risks and risks of 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.

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 would 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 Nuclear Electric Insurance Limited ("NEIL") for approximately $23.1 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 27.4% of employees eligible to retire by the end of 2029. 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 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 are also subject to risks related to the provision of employee healthcare benefits and healthcare reform legislation. Any inability to fully recover these costs in our utility rates would negatively impact our financial condition.

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.

Pending or future federal or state legislative or regulatory activity or court proceedings could increase the costs of providing medical insurance for our employees and retirees. Any potential changes and resulting cost impacts cannot be determined with certainty at this time.

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.

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. 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. A 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.

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.

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 2024 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 ensuring effective controls are in place 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 most severe cases that

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 and Chief Executive Officer, President, 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. For 2024, cybersecurity was identified as a risk. 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 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 risks from cybersecurity threats, including as a result of 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 and our business strategy, results of operations, and financial condition could all be materially impacted. 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 Item 1A—Risk Factors for more information.

ITEM 2. PROPERTIES

Generation Facilities

APS's portfolio of owned generating facilities as of December 31, 2024 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
Cholla 1,3	2		Coal	Base Load	380
Total Steam					1,350
Combined Cycle:					
Redhawk	2		Gas	Load Following	1,136
West Phoenix	5		Gas	Load Following	874
Total Combined Cycle					2,010
Combustion Turbine:					
Ocotillo	7		Gas	Peaking	630
Saguaro	3		Gas	Peaking	189
Douglas	1		Oil	Peaking	18
Sundance	10		Gas	Peaking	430
West Phoenix	2		Gas	Peaking	114
Yucca 1, 2, 3	3		Gas	Peaking	93
Yucca 4	1		Oil	Peaking	54
Yucca 5, 6	2		Gas	Peaking	90
Total Combustion Turbine					1,618
Solar: (d)					
Cotton Center	1		Solar	As Available	17
Hyder I	1		Solar	As Available	17
Paloma	1		Solar	As Available	17
Chino Valley	1		Solar	As Available	20
Gila Bend	1		Solar	As Available	36
Hyder II	1		Solar	As Available	14
Foothills	1		Solar	As Available	38
Luke AFB	1		Solar	As Available	11
Desert Star	1		Solar	As Available	10
Red Rock	1		Solar	As Available	44
Agave Solar	1		Solar	As Available	150
APS Owned Distributed Energy			Solar	As Available	38
Multiple facilities			Solar	As Available	4
Total Solar					416
Total Capacity					6,540

(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 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.
(d) See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Energy Storage" above for details related to APS's energy storage facilities and agreements.

See "Business of Arizona Public Service Company — Environmental Matters" in Item 1 with respect to matters having a possible impact on the operation of certain of APS's generating facilities.

See "Business of Arizona Public Service Company" in 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 24, 2025, APS's transmission facilities consist of approximately 5,817 pole miles of overhead lines and approximately 86 miles of underground lines, 5,757 miles of which are located in Arizona. APS's distribution facilities consist of approximately 11,317 miles of overhead lines and approximately 24,031 miles of underground primary cable (20,893 when excluding abandoned conductor), all of which are located in Arizona. APS also owns and maintains 485 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, 2024:

	Percent Owned (Weighted-Average)
Arizona Nuclear Power Project 500kV System	33.3 %
Navajo Southern System	24.7 %
Palo Verde — Yuma 500kV System	25.5 %
Four Corners Switchyards	58.0 %
Phoenix — Mead System	17.1 %
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 %
Agua Fria Switchyard	10.0 %

Expansion. Each year, APS prepares and files with the ACC a Ten-Year Transmission Plan. In APS's 2025 Ten-Year Plan, APS projects it will develop 184 miles of new transmission lines over the next 10 years. Additionally, APS plans to upgrade 687 miles of existing transmission lines over the same

horizon. The 2025 Ten-Year Plan includes a 28-mile 500kV line from the Jojoba substation to the Rudd substation. The purpose of this 500kV line project is to bring in a new source to the west and southwest parts of the Phoenix metropolitan area which is experiencing rapid economic development. This new source will provide customers in the area greater access to a diverse mix of resources from around the region. Additionally, the 2025 Ten-Year Plan includes the rebuild of both Four Corners to Pinnacle Peak 345kV lines which span 289 miles each. This rebuild will replace aging towers to ensure continued reliability and safety, increase important capability to the Metro Phoenix area, and improve access to a diverse mix of resources from the Four Corners region throughout the Southwest. The 2025 Ten-Year Plan includes numerous projects with the purpose to interconnect new renewable energy resources to the transmission system.

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 allows 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 Item 1 for additional information about the Four Corners right-of-way and lease matters.

Certain portions of our 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 our 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 amounts that we have paid in the past for such rights-of-way. The ultimate cost of renewal of certain of the rights-of-way for our transmission lines is therefore uncertain.

ITEM 3. LEGAL PROCEEDINGS

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

See Note 3 for ACC and FERC-related matters.

See Note 10 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, 2025, current positions and principal occupations for the past five years are as follows:

Name	Age	Position	Period
Jeffrey B. Guldner (a)	59	Chairman of the Board, Chief Executive Officer and President of Pinnacle West	2019-Present
		Chairman of the Board and Chief Executive Officer of APS	2022-Present
		Chairman of the Board, Chief Executive Officer and President of APS	2021-2022
		Chairman of the Board and Chief Executive Officer of APS	2020-2021
		President of APS	2018-2020
		Executive Vice President, Public Policy of Pinnacle West	2017-2019
Elizabeth A. Blankenship	53	Vice President, Controller and Chief Accounting Officer of Pinnacle West and APS	2019-Present
		General Manager, Accounting Operations of APS	2019-2019
		Director, Accounting Operations of APS	2014-2019
Andrew D. Cooper	46	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
		Director, Corporate Finance of Consolidated Edison Company of New York, Inc.	2017-2020
Jose L. Esparza	50	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
		Vice President, Customer Engagement of Southwest Gas	2012-2019
Theodore N. Geisler (a)	46	President of APS, Director on the Pinnacle West and APS Boards of Directors	2024-Present
		President of APS	2022-Present
		Senior Vice President and Chief Financial Officer of Pinnacle West and APS	2020-2022
		Vice President and Chief Information Officer of APS	2018-2020
Adam C. Heflin	61	Executive Vice President and Chief Nuclear Officer, PVGS, of APS	2022-Present
		Chief Executive Officer of Wolf Creek Nuclear Operating Corporation	2014-2019
Paul J. Mountain	47	Vice President, Finance and Planning of Pinnacle West and APS	2024-Present
		Vice President, Finance and Treasurer of Pinnacle West and APS	2022-2024
		Vice President, Finance and Planning of Pinnacle West and APS	2020-2022
		General Manager, Finance of Pinnacle West	2017-2020
Robert E. Smith	55	Executive Vice President, Chief Legal Officer and Chief Development Officer of Pinnacle West and APS	2025-Present
		Executive Vice President, General Counsel and Chief Development Officer of Pinnacle West and APS	2021-2025
		Senior Vice President and General Counsel of Pinnacle West and APS	2018-2021
Jacob Tetlow	52	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
		Vice President, Transmission and Distributions Operations of APS	2017-2020

(a) On December 12, 2024, Pinnacle West announced that Jeffrey B. Guldner will retire from his position as Chairman of the Board, President, Chief Executive Officer and member of the Board of Directors of Pinnacle West and Chairman of the Board, Chief Executive Officer and member of the Board of Directors of APS, effective April 1, 2025. On April 1, 2025, Theodore N. Geisler will replace Mr. Guldner as Chairman of the Board, President, and Chief Executive Officer of Pinnacle West and Chairman of the Board and Chief Executive Officer of APS. He will continue to serve as President of APS and as a director on the Pinnacle West and APS Boards of Directors.

PART II

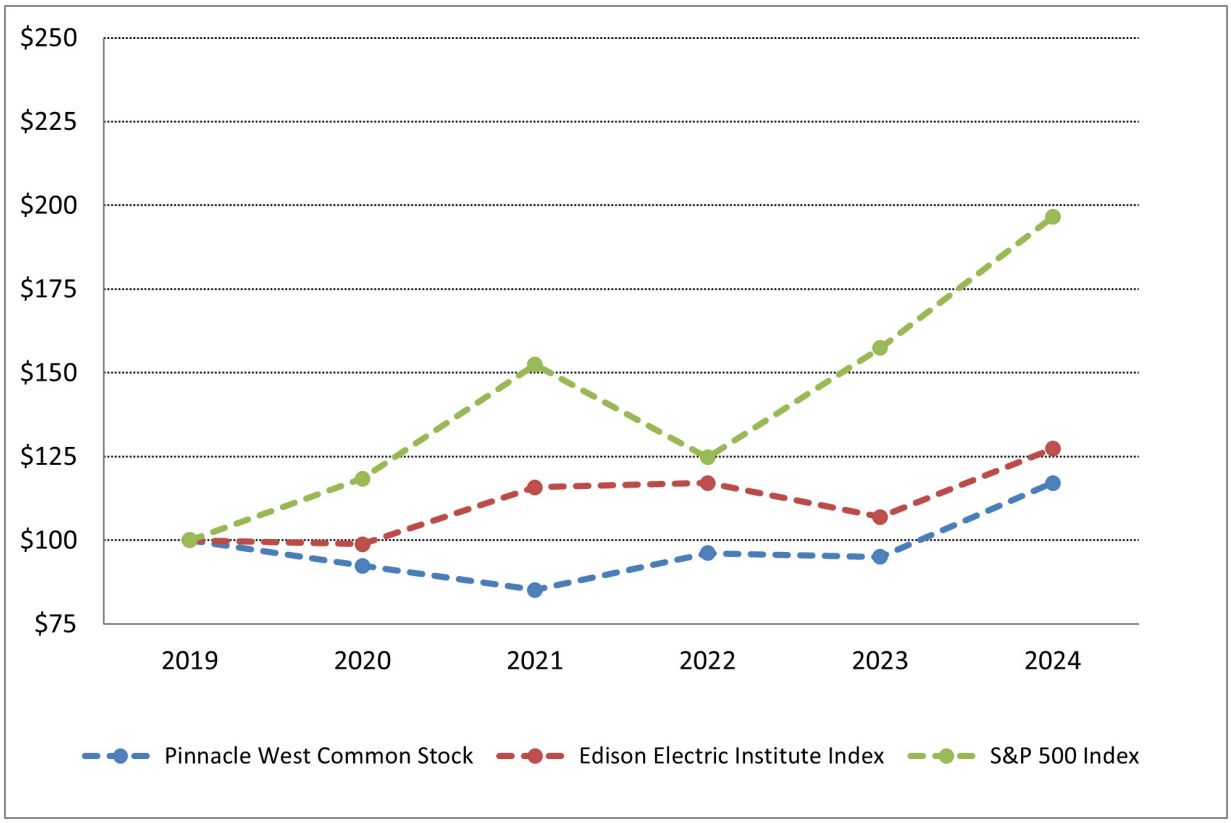
ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

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 20, 2025, Pinnacle West's common stock was held of record by approximately 13,686 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, 2024, 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, 2024, to the cumulative total returns on the S&P 500 Index and the Edison Electric Index. The comparison assumes that $100 was invested on December 31, 2019, in Pinnacle West's common stock and in each of the indices shown and that all of the dividends were reinvested.



	Year Ended December 31,					
Company/Index	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Pinnacle West Common Stock	$100	$92	$85	$96	$95	$117
Edison Electric Institute Index	$100	$99	$116	$117	$107	$127
S&P 500 Index	$100	$118	$152	$125	$157	$197

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 2024 results with 2023 results. For the discussion of 2023 compared to 2022, 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, 2023, 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 $26 billion. Since 1886, Pinnacle West and our affiliates have provided energy and energy-related products to people and businesses throughout Arizona.

Pinnacle West derives essentially all of our revenues and earnings from our principal subsidiary, APS. APS is Arizona's largest and longest-serving electric company that 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.

Strategic Overview

Our strategy is to create a sustainable energy future for Arizona that delivers shareholder value and shared value by serving our customers with reliable, affordable, and clean energy.

Customer-Focused

APS's focus remains on its customers and the communities it serves. Accordingly, it is APS's goal to achieve an industry-leading, best-in-class customer experience. This multi-year objective includes incrementally improving APS's J.D. Power ("JDP") residential and business customer satisfaction ratings from the fourth to the top of second quartile for its customers. For 2024, APS ranked at the top of the second quartile for large investor-owned utilities for both business and residential customers, with the residential results being APS's highest rank and placement since 2016.

In furtherance of a customer-centric culture, APS employees have delivered an enhanced customer experience in recent years through a number of past and ongoing initiatives, such as improving the ease-of-use of APS's automated phone system, improving the speed of answering customer calls, advancing phone advisor soft skill development through updated training curriculum, and adding 1,100-plus in-person payment locations, as well as introducing new customer payment channels. Recently, APS redesigned its customer bills with the aim of increasing personalization and helping customers better understand their

energy use and find ways to save. APS also implemented numerous enhancements to its website, including improving page-loading speeds, adding user-friendly dashboards, and making content more simple, relevant, and useful. APS enhanced other customer touchpoints, such as communications throughout outages and the online outage center in addition to continuing to communicate with customers in their preferred channels about topics that matter most to them, such as reliability, energy-efficiency, financial assistance, the environment, and programs that enable them to design their own personalized energy experience. Finally, APS continues to focus on employee learning, training, tools, and resources to ensure all employees understand their role in APS customers' experiences.

Additionally, APS has implemented a variety of financial assistance programs to support customers struggling to pay their energy bills. Among these assistance programs are discounts for qualified limited-income customers, including a new tier with larger discounts for APS's lowest income customers added in the second quarter of 2024 and other non-income-based assistance programs, such as flexible payment arrangements and emergency utility bill assistance. To ensure our most vulnerable customers are connected to these programs, we train and partner with more than one hundred community action agencies across our service territory.

Reliable

While our energy mix evolves, APS's commitment to deliver reliable service to our customers remains. APS is managing through significant growth in the Phoenix metropolitan area while experiencing supply chain issues similar to those experienced in other industries.

Planned investments will support operating and maintaining the grid, updating technology, accommodating customer growth, and enabling more renewable energy resources. To prioritize reliability and meet substantial growth in customer energy needs, APS has developed a future-focused, strategic transmission plan (the "Ten-Year Transmission Plan"). The Ten-Year Transmission Plan includes five critical transmission projects that comprise the APS strategic transmission portfolio, which represent a significant upgrade to our transmission system. These five projects, along with other projects included in the Ten-Year Transmission Plan, will support growing energy needs, strengthen reliability, and allow for the connection of new resources.

Our advanced distribution management system allows operators to locate outages and control line devices remotely and helps them coordinate more closely with field crews to safely maintain an increasingly dynamic grid. The system will also integrate a new meter data management system that will increase grid visibility and give customers access to more of their energy usage data.

Wildfire safety remains a critical focus for APS and other utilities. We have increased investment in fire mitigation efforts to clear defensible space around our infrastructure, continue ongoing system upgrades, build partnerships with government entities and first responders and educate customers and communities. We 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 recent wildfire events in Hawaii, California, and across North America, we have been devoting and will continue to devote substantial efforts to analyzing and developing enhancements to our systems and processes to mitigate fire risk within our 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 completed implementation of fire modelling software that we are utilizing to more surgically 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 PSPS program on certain feeders that began in the 2024 fire season, leveraging the additional real-time analysis provided by the new modelling software, and has educated and is continuing education outreach to customers and communities that may potentially be impacted by the PSPS program. APS continues to evaluate policy and regulatory options, as well as insurance programs, to mitigate the impact of wildfire events.

For example, 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. APS cannot predict the outcome of this matter. See Note 3 for more information.

Additionally, APS was selected by the 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.

Maintaining reliability and affordability for customers during the clean energy transition is fundamental to APS's strategy. Dispatchable natural gas generators provide energy during times when intermittent resources, such as solar and wind, are insufficient to meet customer demand. In addition to the previously added natural gas units at the modernized Ocotillo Power Plant in 2019 and efficiency improvements to gas units at the Redhawk, Sundance, and West Phoenix Power Plants in 2024, APS has contracted for two simple cycle combustion turbines (approximately 90 MW in total) at Sundance, which are expected to be in service in 2026, and eight simple cycle combustion turbines (approximately 397 MW in total) at Redhawk, which are expected to be in service in 2028. APS continues to evaluate and pursue options for reliably serving growing customer energy needs and demand.

In October 2021, APS announced plans to evaluate regional market solutions as part of the Western Markets Exploratory Group ("WMEG"). As a member of WMEG, APS explored the potential for a staged approach to new market services, including day-ahead energy sales, transmission system expansion, and other power supply and grid solutions consistent with existing regulations and known and expected market design. APS utilizes the work done by WMEG to help identify market solutions that can help achieve carbon reduction goals while supporting reliable, affordable service for customers.

APS went live with a new Energy Management System ("EMS") in April 2024. APS expects the new EMS to provide a better foundation which will improve future integration of the renewable and energy storage assets into APS's generation resource portfolio, allowing APS to maximize the flexibility of its resources and fully engage in the Western Energy Imbalance Market ("WEIM"). APS also believes it will better position APS to participate in market opportunities that develop over the next decade.

APS's key elements to delivering reliable power include resource and transmission planning, sufficient reserve margins, partnering with customers to manage peak demand, fire mitigation, and operational preparedness, among others. Seasonal readiness procedures at APS include inspections to ensure good material conditions and critical control system surveys. APS also plans for the unexpected by conducting emergency operations drills and coordinating with federal, state, and local agencies on fire and emergency management.

Affordable

APS continues to focus on mitigating the cost pressures related to inflation and other factors, such as tariffs. Overall inflation grew by 1.6% in Phoenix and 2.9% nationally over the twelve months ended December 2024. Although inflationary impacts to APS began to slow in 2024, APS is still managing the impacts high inflation. Additionally, the implementation of recent and future tariffs could further escalate costs and introduce supply chain constraints.

APS's customer affordability initiative includes internal opportunities, such as training and mentoring employees on identifying efficiency opportunities; maintaining an 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 areas such as transformers; and implementing automation technologies to enhance efficiencies and increase data-oriented decision making.

There are also external opportunities under APS's customer affordability initiative, such as APS's participation in the WEIM. WEIM continues to be a tool for creating savings for APS's customers from the real-time, voluntary market. APS continues to expect that its participation in 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 Southwest Power Pool ("SPP"). The Markets+ tariff was filed with FERC on March 29, 2024 and was approved on January 16, 2025. APS announced a market decision to pursue participation in SPP Markets+. In addition, APS is participating in the Western Resource Adequacy Program administered by Western Power Pool and is transitioning to full binding participation as early as summer 2027. These regional efforts are driven by the objectives of reducing customer cost and improving reliability.

In terms of generation affordability, every three years, APS performs a comprehensive study, called an Integrated Resource Plan ("IRP"), to identify what resources will be necessary to safely and reliably 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 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 in the most affordable and sustainable manner possible. To help ensure competitive costs for resources procured by APS, APS regularly issues competitive bid solicitations through the ASRFP process, with the most recent ASRFPs being issued in 2022, 2023, and 2024. 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. Through the ASRFP process, APS has found that clean resources like wind, solar, and energy storage technology, are important elements of a least cost portfolio. During the clean energy transition, dispatchable resources will play a vital role in maintaining grid reliability by serving as a back-up to intermittent energy resources when output is insufficient to meet customer needs. Over the long term, each resource in a balanced and diverse portfolio is expected to provide complementary value and contribute to sustained delivery of reliable electric service.

In addition to managing the cost of electricity generation, APS has continued building upon existing cost management efforts, including a customer affordability initiative launched in 2019. The initiative was implemented company-wide to thoughtfully and deliberately assess our business processes

and organizational approaches to completing high-value work and achieving internal efficiencies. APS continues to drive this initiative by identifying opportunities to streamline its business processes, mitigate cost increases, increase employee retention, and improve customer satisfaction.

Clean Energy Commitment

We are committed to doing our part to build a clean and carbon-free future. As Arizona stewards, we do what is right for the people and prosperity of Arizona. Our vision is to create a sustainable energy future for Arizona by providing reliable, affordable, and clean energy to our customers. We can accomplish our vision by collaborating with customers, communities, employees, policymakers, shareholders, and other stakeholders. Our clean energy commitment is based on sound science and supports continued growth and economic development while maintaining reliability and affordable prices for APS's customers.

APS's clean energy commitment consists of three parts:

- A 2050 goal to provide 100% clean, carbon-free electricity;
- A 2030 target to achieve a resource mix that is 65% clean energy, with 45% of the generation portfolio coming from renewable energy; and
- A plan to exit from coal-fired generation by 2031.

APS's ability to successfully execute its clean energy commitment depends upon a number of important external factors, including a supportive regulatory environment, sales and customer growth, development of clean energy technologies, and continued access to capital markets, among others.

2050 Goal: 100% Clean, Carbon-Free Electricity. Achieving a fully clean, carbon-free energy mix by 2050 is our aspiration. Achieving this 2050 goal will require, among other things, innovative thinking, emergent clean energy and storage technologies, upgrades and expansions to the grid, and supportive public policy.

2030 Goal: 65% Clean Energy. APS has an energy mix that is already more than 50% clean and plans to continue to add more renewables and energy storage. By building on those plans, APS intends to attain an energy mix that is 65% clean by 2030, with 45% of APS's generation portfolio coming from renewable energy. "Clean" is measured as percent of energy mix, which includes all carbon-free resources like nuclear, renewables, and demand-side management. "Renewable" energy includes generation resources such as solar, wind, and biomass, and is measured in accordance with the ACC Renewable Energy Standard as a percentage of retail sales. This target will serve as a checkpoint for our resource planning, investment strategy, and customer affordability efforts as APS moves toward a 100% clean, carbon-free energy mix by 2050.

2031 Goal: Exit Coal-Fired Generation. The plan to exit coal-fired generation by 2031 will require APS to stop relying on coal-generation at Four Corners. APS has permanently retired more than 1,000 MW of coal-fired electric generating capacity. These closures and other measures taken by APS have resulted in annual carbon emissions that were 36% lower in 2023 compared to 2005. In addition, APS has committed to end the use of coal at its remaining Cholla units during 2025.

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, subject to the

necessary governmental approvals and conditions associated with changes in plant ownership. 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.

Renewables. APS's IRP identifies a diverse mix of resources adequate to maintain grid reliability while serving increasing future customer energy needs. Our IRP shows that renewable and clean resources are an important part of a reliable, cost effective portfolio. APS seeks market-based pricing of procured resources through regular solicitation of project bids using its competitive ASRFP process.

APS has a diverse portfolio of existing and planned resources, including solar, wind, energy storage, nuclear, geothermal, biomass and biogas, that supports our commitment to clean energy. This commitment is already strengthened by Palo Verde, one of the nation's largest carbon-free, clean energy resources, which provides the foundation for reliable and affordable service for APS customers. APS's longer-term clean energy strategy includes pursuing the right mix of purchased power contracts for new resources, procurement of new resources to be owned by APS, and the ongoing development of distributed energy resources. Maintaining a balanced and diverse portfolio of resources will ensure continued reliable service to our customers in the most affordable manner possible.

APS uses competitive ASRFPs to pursue market-priced resources that meet its system needs and offer the best value for customers. APS selects projects based on cost, ability to meet system requirements and commercial viability, taking into consideration timing and likelihood of successful contracting and development. Under current market conditions, APS must aggressively contract for resources that can withstand supply chain and other geopolitical pressures. 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.

On June 30, 2023, APS issued an ASRFP (the "2023 ASRFP") pursuant to which APS procured nearly 7,300 MW of new resources to be in service from 2026 to 2028.

On November 20, 2024, APS issued an ASRFP (the "2024 ASRFP") seeking 2,000 MW of resources. APS is seeking projects that can reach commercial operation beginning June 1, 2028 through June 1, 2030 but will consider projects that may achieve commercial operation as early as 2026. Additionally, APS is interested in projects that require longer planning, permitting, and construction and can be commercially operational after June 1, 2030. Bids for the 2024 ASRFP were due on February 5, 2025.

The following table summarizes the resources in APS's renewable energy portfolio that are in operation, planned or 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.

	Net Capacity in Operation (MW)	Net Capacity Planned / Under Development (MW)	
Total APS Owned: Solar	416	168	
PPAs Renewables:			
Solar	585	3,321	
Wind	853	500	
Geothermal	10	—	
Biomass	14	—	
Biogas	3	—	
Total PPAs	1,465	3,821	
Total Distributed Energy: Solar (a)	1,727	63	(b)
Total Renewable Portfolio	3,608	4,052	

(a) Includes rooftop solar facilities owned by third parties. DG is produced in direct current and is converted to alternating current for reporting purposes.
(b) Applications received by APS that are not yet installed and online.

Energy Storage. 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 to further our understanding of how storage works with other advanced technologies and the grid.

The following table summarizes the resources in APS's energy storage portfolio that are in operation, planned or under development as of the date of this report. Agreements for the development and completion of future resources are subject to various conditions.

	Net Capacity in Operation (MW)		Net Capacity Planned / Under Development (MW)
APS Owned Energy Storage	201	(a)	150
PPAs Energy Storage	405		5,087
Customer-Sited Energy Storage	62		51
Total Energy Storage Portfolio	**668**		**5,288**

(a) Includes 0.3 MW of APS-owned customer-sited energy storage.

Palo Verde. Palo Verde, one of the nation's largest carbon-free, clean energy resources, will continue to be a foundational part of APS's resource portfolio. Palo Verde is not just the cornerstone of our current clean energy mix; it also is a significant provider of clean energy to the southwestern United States. The plant is a critical asset to the Southwest, generating more than 32 million MWh annually –

enough power for roughly 3.4 million households, or approximately 8.5 million people. Its continued operation is important to a carbon-free and clean energy future for Arizona and the region, as a reliable, continuous, affordable resource and as a large contributor to the local economy.

Developing Clean Energy Technologies

New Nuclear Generation

APS, along with other Arizona electric utilities, is exploring new nuclear generation to provide around-the-clock carbon-free energy to meet rising energy demands in Arizona. APS has been monitoring emerging nuclear technologies, such as small modular nuclear reactors ("SMRs"). SMRs 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 the 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.

Electric Vehicles

As a part of the statewide transportation electrification plan ("TE Plan") adopted in 2021, the ACC approved a target of 450,000 light-duty electric vehicles ("EVs") in APS's service territory by 2030. APS's Take Charge AZ ("TCAZ") program has helped to deploy Level 2 EV charging stations on customer properties for fleet, public, and workplace EV charging. As of December 31, 2024, APS has installed 829 energized Level 2 charging ports at 197 customer locations. Additionally, APS has energized direct current fast charging stations that are owned and operated by APS at five locations in Arizona: Sedona, Prescott, Globe, Show Low, and Payson. Effective December 12, 2023, the TCAZ program was discontinued by the ACC. As part of that decision, APS was permitted to complete certain projects that were in process as of December 12, 2023.

Additionally, as part of APS's DSM Implementation Plan, APS launched the EV Charging Demand Management Pilot to proactively address the growing electric demand from charging as EVs become more widely adopted. The EV programs in the DSM Implementation Plan include APS SmartCharge (an EV data gathering program), Fleet Advisory Services, and a $100 rebate to home builders for new homes to be built EV-ready with 240V receptacle. APS previously offered a $250 residential rebate to customers that purchased a qualifying home Level 2 charger. Effective December 12, 2023, APS discontinued this rebate per the ACC decision. See the discussion above.

APS filed its 2024 DSM Implementation Plan on November 30, 2023. The 2024 DSM Implementation Plan includes APS's 2024 TE Plan and, among other things, proposes two new programs that were initially proposed in the 2023 DSM Implementation Plan: an expanded residential EV Managed Charging program and a Commercial EV Make-Ready Program. On April 26, 2024, APS filed an amended 2024 DSM Implementation Plan. The amended 2024 DSM Implementation Plan includes an updated budget of $90.9 million to reflect removal of incentive funds for the Level 2 Smart Charger rebate within the EV Charging Demand Management Pilot, an update on the performance incentive calculation, and the withdrawal of tranches two and three of the residential battery pilot. The amended 2024 DSM Plan is still pending ACC review and approval. APS will not file a 2025 DSM Implementation Plan, pending ACC review of the amended 2024 DSM Implementation Plan. APS cannot predict the outcome of this proceeding.

Carbon Capture

Carbon Capture Utilization and Storage ("CCUS") technologies can isolate CO_2 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. CCUS technologies are still in the demonstration phase and while they show promise, they are still being tested in real-world conditions. These technologies could offer the potential to keep in operation existing generators that otherwise would need to be retired. APS will continue to monitor this emerging technology.

Sustainability Practices

In 2020, in support of our clean energy commitment and the growing focus on sustainability within our organization, we increased our focus on sustainability by dedicating a new Sustainability Department at Pinnacle West responsible for integrating responsible business practices into the everyday work of the Company.

In 2024, the Sustainability Department engaged an external consultant and leveraged input from employees, large customers, limited-income advocates, economic development groups, tribes, nonprofits, environmental non-governmental organizations, residential customers, and other stakeholders to identify and assess the sustainability issues that matter most. In total, 15 Priority Sustainability Issues ("PSIs") were identified and prioritized. The top five issues that were prioritized by stakeholders are as follows: energy affordability, electric reliability, clean energy and decarbonization, workforce development, and climate resilience and adaptation. Understanding the sustainability priorities of internal and external stakeholders can help companies improve performance, identify risks and opportunities, and refine sustainability strategy.

Finally, the Company maintains an annual Corporate Responsibility Report on the Pinnacle West website (*www.pinnaclewest.com/corporate-responsibility*). The report provides information related to the Company's sustainability practices and performance. The information on Pinnacle West's website, including the Corporate Responsibility Report, is not incorporated by reference into or otherwise a part of this report.

Artificial Intelligence

To address the rapid advancement of artificial intelligence technology risks and opportunities, APS has developed a cross functional governance structure with leadership and experts from our information technology, cybersecurity, human resources, ethics, supply chain, legal, and nuclear generation teams. This cross functional structure assesses the opportunities and risks in alignment with enterprise strategy to ensure compliance with data security and reliability requirements as well as our Code of Ethical Conduct, while observing market trends in this rapidly evolving area.

Regulatory Overview

APS expects to file an application with the ACC for its next general rate case mid-year 2025 and is continuing to evaluate the timing of such filing.

2022 Retail Rate Case

APS filed an application with the ACC on October 28, 2022 (the "2022 Rate Case") seeking an increase in annual retail base rates.

On January 25, 2024, an Administrative Law Judge issued a ROO in the 2022 Rate Case, as corrected on February 6, 2024 (the "2022 Rate Case ROO"). The 2022 Rate Case ROO recommended, among other things, (i) a $523.1 million increase in the annual base rate 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 4.36%, (v) 12 months of post-test year plant and the inclusion of the Four Corners Effluent Limitations Guideline ("ELG") project, (vi) the approval of APS's System Reliability Benefit ("SRB") proposal with certain procedural and other modifications, (vii) no additional Coal Community Transition ("CCT") funding, (viii) a 5.0% return on the prepaid pension asset and a return of 5.35% on the OPEB liability, and (ix) no disallowances on APS's coal contracts.

The 2022 Rate Case ROO also recommended a number of changes to existing adjustors, including (i) the approval of modified DSM performance incentives and the requested DSM transfer to base rates, (ii) the retention of $1.9 million of Renewable Energy Adjustment Charge ("REAC") in the adjustor rather than base rates, (iii) a partial transfer of $27.1 million of LFCR funds to base rates, and (iv) the adoption of an increase in the annual PSA cap to $0.006/kWh.

On February 22, 2024, the ACC approved a number of amendments to the 2022 Rate Case ROO 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's decision results in an expected total net annual revenue increase for APS of approximately $253.4 million and a roughly 8% increase to the typical residential customer's bill. 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 CCT funding. On April 15, 2024, the ACC granted, in part, the rehearing applications of the Attorney General, Arizona Solar Energy Industries Association, Solar Energy Industries Association, 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. 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 Commission's December 17, 2024 decision on the rehearing. The Commission has taken no action on these requests. In addition, each of these parties have subsequently filed notices of appeal to the Arizona Court of Appeals seeking review of the Commission's decisions regarding the GAC and on rehearing. APS cannot predict the outcome of these proceedings.

2019 Retail Rate Case

On October 31, 2019, APS filed an application with the ACC (the "2019 Rate Case") for an annual increase in retail base rates. On August 2, 2021, an Administrative Law Judge issued a ROO in the 2019 Rate Case (the "2019 Rate Case ROO") and issued corrections on September 10 and September 20, 2021. Subsequently, the ACC approved an amended 2019 Rate Case ROO on November 2, 2021.

After the 2019 Rate Case decision, APS filed an application for rehearing of the 2019 Rate Case and later filed a Notice of Direct Appeal by APS at the Arizona Court of Appeals, requesting review of certain matters from the 2019 Rate Case decision. The Arizona Court of Appeals affirmed in part and reversed in part the ACC's decision in the 2019 Rate Case, remanding the issue to the ACC for further proceedings. On June 14, 2023, APS and the ACC Legal Division filed a joint resolution with the ACC to allow recovery of $215.5 million in costs related to the installation of the Four Corners selective catalytic reduction ("SCR") project, a reversal of the 20 basis points reduction to APS's return on equity from 8.9% to 8.7% as a result of the 2019 Rate Case decision, and recovery of $59.6 million in revenue lost by APS between December 2021 and June 20, 2023. The joint resolution provides for a new Court Resolution Surcharge ("CRS") mechanism, which is designed to recover the $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. On June 21, 2023, the ACC approved the joint resolution and proposals therein for recovery through the CRS mechanism, which became effective on July 1, 2023. As of December 31, 2024, $26.2 million of the $59.6 million of lost revenue has been recovered. Finally, the CRS tariff has been updated to account for changes to return on equity and depreciation and deferral adjustments approved in Decision No. 79293 in the 2022 Rate Case.

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 allows regulated utilities to propose formula rate plans in future rate cases. Proposed plans must be based on a historical test year, include an annual update with a true-up and an earnings test to ensure a utility earns within a 20 basis points band of its authorized return on equity. Proposed plans should also include an annual meeting and challenge periods for stakeholder feedback. Utilities that implement formula rates also must file a full rate case at least every five years unless an alternate schedule is set by the ACC. APS cannot predict the outcome of this matter.

Cholla

On August 14, 2024, APS filed a request with the ACC for a deferral order associated with unrecovered book value and closure costs of the remaining Cholla units. This order would authorize APS to defer, for future recovery in rates, both the expenses necessary to close and decommission 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. APS cannot predict the outcome of this matter.

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. APS cannot predict the outcome of this matter.

See Note 3 for information regarding additional regulatory matters.

Captive Insurance Cell

Pinnacle West is the primary beneficiary of a protected cell captive insurance company. The Captive provides insurance coverage to Pinnacle West and our subsidiaries that supplements third-party insurance policies. 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 10. The Captive may hold investment assets in cash, cash equivalents, and equity and fixed income instruments.

Inflation Reduction Act of 2022

The Inflation Reduction Act of 2022 ("IRA") significantly expands the availability of tax credits for investments in clean energy generation technologies and energy storage. Key provisions that are relevant to APS's clean energy commitment include (i) an extension of tax credits for solar and wind generation, including a new option for solar investments to claim a Production Tax Credit ("PTC") in lieu of the Investment Tax Credit ("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. The Internal Revenue Service and U.S. Treasury Department have issued preliminary guidance related to various provisions of the IRA that have enabled APS to claim credits related to its solar and energy storage investments. The Company continues to await regulations and other guidance, including with respect to the nuclear PTC, which will provide additional details and clarifications regarding how the Company may be able to claim IRA tax credits. See Note 4 for more information.

The prospects for federal tax reform, including potential modification or repeal of the IRA tax provisions, have increased due to the results of the 2024 election. Any such reform may impact the availability of future potential tax benefits from the IRA and could impact the Company's effective tax rate, cash taxes paid and other financial results such as earnings per share, gross revenues, and cash flows. We cannot predict the timing or extent of such tax-related developments which, absent appropriate regulatory treatment, may have a negative impact on our financial results.

Financial Strength and Flexibility

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 will 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. On August 4, 2023, Pinnacle West entered into a purchase and sale agreement pursuant to which we agreed to sell all of our equity interest in our wholly-owned subsidiary BCE to Ameresco (the "BCE Sale"). The transaction was accounted for as the sale of a business and closed in multiple stages. The final closing of the BCE Sale was completed on January 12, 2024. See Note 20 for additional details. 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.

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 venture partners' utility affiliates. The U.S. Department of Energy's Grid Deployment Office selected TransCanyon to enter into capacity contract negotiations for up to 25% of the Cross-Tie 500-kilovolt transmission line ("Cross-Tie") as part of the Transmission Facilitation Program. The agreement was executed on June 12, 2024. The proposed Cross-Tie project 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.

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 is a wholly-owned subsidiary of Pinnacle West. 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 the following:

- $25 million investment in the Energy Impact Partners fund, of which approximately $18.8 million has been funded as of December 31, 2024. 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 (formerly invisionAZ Fund), of which approximately $11.8 million has been funded as of December 31, 2024. 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 $1.2 million has been funded as of December 31, 2024. Westly Seed Fund is focused on supporting entrepreneurs involved in the energy, mobility, building, and industrial sectors.

- Equity investment in SAI Advanced Power Solutions ("SAI"), a private corporation that manufactures electrical switchgear equipment used by data centers. El Dorado accounts for this investment under the equity method, with a December 31, 2024 investment carrying value of zero. SAI has seen an increased demand for their customized switchgear products. El Dorado has no funding commitments to SAI.

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 the years 2022 through 2024, retail electric revenues comprised approximately 92% 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. These revenue transactions 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 2.1% for the year ended December 31, 2024, compared with the prior-year period. For the three years through 2024, APS's customer growth averaged 2.1% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2025 and the average annual growth to be in the range of 1.5% to 2.5% through 2027 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 5.7% for the year ended December 31, 2024, compared with the prior-year period. While steady customer growth was somewhat offset by weaker usage among residential customers, energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives, the main drivers of positive sales for this period were continued strong sales to commercial and industrial customers and the ramp-up of new data center and large manufacturing customers.

For the three years through 2024, annual retail electricity sales growth averaged 3.2%, adjusted to exclude the effects of weather variations. Due to the expected growth of several large data centers and new 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 2025 and that average annual growth will be in the range of 4.0% to 6.0% through 2027, 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 large data centers and new large manufacturing facilities, which are expected to contribute to 2025 growth in the range of 3.0% to 5.0% and to average annual growth in the range of 3.0% to 5.0% through 2027.

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 now receiving unprecedented incremental requests for service from extra-large commercial energy users (over 25 MW) with very high energy demands that persist virtually around-the-clock. These incremental requests for service by extra-large energy users far exceed available generation and transmission resource capacity in the Southwest region for the foreseeable future. In April 2023, APS notified prospective extra-large customers without existing commitments from APS that it is not able to commit at this time to future extra-large projects of over 25 MW. Because of the high growth in demand for such projects, APS has developed a prioritization queue that identifies and prioritizes projects while maintaining system reliability and affordability for existing APS customers. APS is exploring available options for securing sufficient electric generation and transmission to meet these projections of future customer needs.

Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as economic conditions, customer growth, usage patterns and energy conservation, slower ramp-up of and/or fewer data centers and large 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 $24 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 $6 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 Costs. Fuel and purchased power costs 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 7.

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 9.7% of the assessed value for 2024, 10.0% for 2023, and 10.2% for 2022. Property taxes increased in 2024 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 property 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, 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 Note 6 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. An allowance for borrowed funds used during construction 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 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 segment activities are conducted through our wholly-owned subsidiary, APS. All other operating segment activities are insignificant to Pinnacle West.

Operating Results – 2024 compared with 2023

Our consolidated net income attributable to common shareholders for the year ended December 31, 2024, was $609 million, compared with consolidated net income attributable to common shareholders of $502 million for the prior-year period. The results reflect an increase of approximately $107 million, primarily as a result of the impacts of new customer rates, increased customer usage and growth, the effects of weather, and higher CRS revenue and LFCR revenue. These positive factors were partially offset by higher operations and maintenance expense, higher depreciation and amortization expense mostly due to increased plant and intangible assets, higher interest charges, net of AFUDC, higher income taxes and lower transmission revenues.

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

	Pinnacle West Consolidated			APS Consolidated		
	Year Ended December 31,			Year Ended December 31,		
	2024	2023	Net Change	2024	2023	Net Change
	(dollars in millions)					
Operating revenues	$ 5,125	$ 4,696	$ 429	$ 5,125	$ 4,696	$ 429
Fuel and purchased power expense	(1,823)	(1,793)	(30)	(1,823)	(1,793)	(30)
Operating revenues less fuel and purchased power expenses	3,302	2,903	399	3,302	2,903	399
Operations and maintenance	(1,165)	(1,059)	(106)	(1,159)	(1,044)	(115)
Depreciation and amortization	(895)	(794)	(101)	(895)	(794)	(101)
Taxes other than income taxes	(227)	(224)	(3)	(227)	(224)	(3)
Allowance for equity funds used during construction	39	53	(14)	39	53	(14)
Pension and other postretirement non-service credits, net	49	41	8	49	42	7
Other income and expenses, net	11	7	4	(11)	7	(18)
Interest charges, net of allowance for borrowed funds used during construction	(377)	(331)	(46)	(312)	(285)	(27)
Income taxes	(111)	(77)	(34)	(127)	(94)	(33)
Less income related to noncontrolling interests	(17)	(17)	—	(17)	(17)	—
Net Income Attributable to Common Shareholders	$ 609	$ 502	$ 107	$ 642	$ 547	$ 95

Operating revenues less fuel and purchased power expenses. Operating revenues less fuel and purchased power expenses were $399 million higher for the year ended December 31, 2024, compared with the prior-year period. The following table summarizes the major components of this change:

	Increase (Decrease)		
	Operating revenues	Fuel and purchased power expenses	Net change
	(dollars in millions)		
Impact of new rates from the 2022 Rate Case, effective March 8, 2024 (Note 3)	$ 260	$ —	$ 260
Higher retail revenue due to changes in usage patterns and customer growth partially offset by the impacts of energy efficiency and related pricing	112	55	57
Effects of weather	76	23	53
CRS revenue (Note 3)	17	—	17
Higher renewable energy regulatory surcharges, partially offset by operations and maintenance costs	21	4	17
LFCR revenue (Note 3)	16	—	16
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	(61)	(52)	(9)
Lower transmission revenues (Note 3)	(12)	—	(12)
Total	$ 429	$ 30	$ 399

Operations and maintenance. Operations and maintenance expenses increased $106 million for the year ended December 31, 2024, compared with the prior-year period primarily due to:

- an increase of $27 million related to information technology costs;
- an increase of $25 million related to transmission, distribution, and customer service costs;
- an increase of $20 million related to non-nuclear generation costs, primarily due to increased planned outages;
- an increase of $16 million related to employee benefit costs;
- an increase of $14 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 $7 million related to corporate resource costs; and
- a decrease of $3 million for other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $101 million higher for the year ended December 31, 2024, compared to the prior-year period, primarily due to increased plant in service and intangible assets.

Interest charges, net of allowance for borrowed funds and equity funds used during construction. Interest charges, net of AFUDC, were $60 million higher for the year ended December 31, 2024, compared to the prior-year period, primarily due to higher debt balances and higher interest rates in the current period, higher allowance for borrowed funds and lower allowance for equity funds.

Other income and expenses, net. Other income and expenses, net were $4 million higher for the year ended December 31, 2024, compared to the prior-year period, primarily due to the gain on the sale of BCE, partially offset by higher corporate giving expense. See Note 16. The difference between APS's and Pinnacle West's other income and expense, net is primarily related to Pinnacle West's gain on the sale of BCE.

Income taxes. Income taxes were $34 million higher for the year ended December 31, 2024, compared with the prior-year period, primarily due to higher pre-tax income, and lower tax benefits from AFUDC equity, partially offset by higher tax credits.

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 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. At December 31, 2024, APS's common equity ratio, as defined, was 52%. Its total shareholder equity was approximately $8.3 billion, and total capitalization was approximately $15.9 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $6.4 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. 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 loan 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. 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 June 12, 2024, Pinnacle West contributed $450 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness. On December 23, 2024, Pinnacle West contributed $345 million into APS in the form of an equity infusion. APS used this contribution to repay a portion of commercial paper borrowings and for other general corporate purposes.

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 2029. See Note 5.

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. As of December 31, 2024, approximately $850 million of common stock is available to be issued under the ATM program, which takes into account the forward sale agreement in effect as of December 31, 2024.

In addition to the ATM program, Pinnacle West has forward sale agreements from an equity offering in February 2024 in effect as of December 31, 2024. In December 2024, Pinnacle West partially settled the February 2024 Forward Sale Agreements with the issuance of 5,377,115 shares of common stock and received net proceeds of $345 million. The proceeds were recorded in equity. At December 31, 2024, Pinnacle West could have settled the remaining February 2024 Forward Sale Agreements with the issuance of 5,863,486 shares of common stock in exchange for cash of $377 million. For additional information regarding common stock issuances, the ATM program, and outstanding forward sale agreements, see Note 13.

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, 2024, and 2023 (dollars in millions):

Pinnacle West Consolidated

	2024	2023	Net Change
Net cash flow provided by operating activities	$ 1,610	$ 1,207	$ 403
Net cash flow used for investing activities	(1,934)	(1,694)	(240)
Net cash flow provided by financing activities	323	487	(164)
Net decrease in cash and cash equivalents	$ (1)	$ —	$ (1)

Arizona Public Service Company

	2024	2023	Net Change
Net cash flow provided by operating activities	$ 1,610	$ 1,275	$ 335
Net cash flow used for investing activities	(1,986)	(1,687)	(299)
Net cash flow provided by financing activities	375	412	(37)
Net decrease in cash and cash equivalents	$ (1)	$ —	$ (1)

Operating Cash Flows

2024 Compared with 2023. Pinnacle West's consolidated net cash provided by operating activities was $1,610 million in 2024 compared to $1,207 million in 2023, an increase of $403 million in net cash provided, primarily due to $447 million higher cash receipts from electric revenues, $236 million lower fuel and purchased power costs, $15 million change in net collateral, partially offset by $125 million higher income taxes paid, $104 million higher payments for operations and maintenance costs, $49 million higher interest payments and $17 million of other changes in working capital. The difference between APS's and Pinnacle West's net cash provided by operating activities primarily relates to APS's higher income tax cash payments to Pinnacle West 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. Under ERISA, the qualified pension plan was estimated to be 100% funded as of January 1, 2025, and was 113% as of January 1, 2024. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We did not make any contributions to our pension plan in 2024 and 2023. 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 2025, 2026 or 2027. Regarding contributions to our other postretirement benefit plan, we did not make any contributions in 2024 or 2023 and do not expect to make any contributions in 2025, 2026 or 2027. The Company was reimbursed $27 million in 2024, $23 million in 2023, and $26 million in 2022 for prior years retiree medical claims from the other postretirement benefit plan trust assets. 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. For instance, our pension plan's funded status, as measured for accounting principles generally accepted in the United States of America ("GAAP") purposes, was 99% funded as of December 31, 2024, and our postretirement benefit plans were 195% funded, as measured for GAAP purposes at December 31, 2024. See Note 7 for additional details.

Investing Cash Flows

2024 Compared with 2023. Pinnacle West's consolidated net cash used for investing activities was $1,934 million in 2024 compared to $1,694 million in 2023, an increase of $240 million primarily related to $272 million of increased capital expenditures and $21 million of additional investing activity, partially offset by proceeds of $61 million from the BCE Sale. See Note 20. The difference between APS's and Pinnacle West's net cash used for investing activities primarily relates to the BCE Sale and investments into the Captive Insurance Cell VIE. See Note 17.

Capital Expenditures. The following table summarizes the estimated capital expenditures for the next three years:

Capital Expenditures
(dollars in millions)

	Estimated for the Year Ended December 31,		
	2025	**2026**	**2027**
APS			
Generation:			
Clean:			
Nuclear Generation	$ 150	$ 165	$ 185
Renewables and Energy Storage Systems ("ESS")	335	165	430
Other Generation (a)	420	540	335
Distribution	665	670	675
Transmission	450	675	750
Other	380	335	275
Total APS	$ 2,400	$ 2,550	$ 2,650

(a) Includes gas generation and environmental projects.

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 clean resources, including nuclear plants, renewables and ESS, as well as additions and improvements to existing fossil plants. 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 will 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

2024 Compared with 2023. Pinnacle West's consolidated net cash provided by financing activities was $323 million in 2024 compared to $487 million in 2023, a decrease of $164 million in net cash provided primarily due to $842 million higher long-term debt repayments and a net decrease in short-term debt borrowings of $283 million, partially offset by $624 million in higher issuances of long-term debt and an equity issuance of $345 million.

APS's consolidated net cash provided by financing activities was $375 million in 2024 compared to $412 million in 2023, a decrease of $37 million in net cash provided primarily due to a net decrease in

short-term borrowings of $374 million, $250 million higher long-term debt repayments and $50 million in lower issuances of long-term debt, partially offset by $645 million in higher equity infusions.

Significant Financing Activities. On December 11, 2024, the Pinnacle West Board of Directors declared a dividend of $0.895 per share of common stock, payable on March 3, 2025, to shareholders of record on February 3, 2025. During 2024, Pinnacle West increased its indicated annual dividend from $3.52 per share to $3.58 per share. For the year ended December 31, 2024, Pinnacle West's total dividends paid per share of common stock were $3.54 per share, which resulted in dividend payments of $395 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 5 for more information on available credit facilities.

Equity Offerings. Pinnacle West 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. On December 31, 2024, Pinnacle West could have settled the outstanding November 2024 ATM Forward Sale Agreement with the physical delivery of 552,833 shares of Pinnacle West common stock in exchange for cash of approximately $50 million. As of December 31, 2024, Pinnacle West has not received any proceeds relating to the November 2024 Forward Sale Agreement. In addition to the ATM program, Pinnacle West entered into certain equity forward sale agreements in February 2024, which were partially settled in December 2024 with the issuance of 5,377,115 shares of common stock. In connection with the partial settlement, Pinnacle West received net proceeds of $345 million. At December 31, 2024, Pinnacle West could have settled the remaining February 2024 Forward Sale Agreements with the issuance of 5,863,486 shares of common stock in exchange for cash of $377 million. See Note 13.

Other Financing Matters. See Note 15 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%. At December 31, 2024, the ratio was approximately 59% for Pinnacle West and 49% 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 loan agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under certain other material agreements. All of APS's bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these bank

agreements if APS were to default under certain other material agreements. Pinnacle West and APS do not have a material adverse change restriction for credit facility borrowings.

On December 17, 2024, the ACC issued a financing order reaffirming the 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 approving an increase of the long-term debt limit to $9.5 billion and a limit of permitted annual 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 long-term debt provisions and further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of February 18, 2025, 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. On March 7, 2024, S&P affirmed the ratings and revised Pinnacle West's and APS's outlooks from negative to stable. On March 20, 2024, Moody's downgraded both Pinnacle West's and APS's credit ratings by a notch and revised their outlooks from negative to stable. On March 26, 2024, Fitch affirmed APS's ratings and downgraded Pinnacle West's ratings by a notch. Fitch revised the outlook for both Pinnacle West and APS from negative to stable. 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 2050 and bear interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using average rates at December 31, 2024. See Note 6.

- Pinnacle West and APS maintain committed revolving credit facilities. See Note 5 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 3 and 10. Purchase obligations include capital expenditures and other obligations. See Note 10. Commitments related to purchased power lease contracts are also considered fuel and purchased power commitments. See Note 8.

- APS holds certain contracts to purchase renewable energy credits in compliance with the RES. See Notes 3 and 10.

- APS is required to make payments to the noncontrolling interests related to the Palo Verde sale leaseback through 2033. See Note 17.

- APS must reimburse certain coal providers for final and contemporaneous coal mine reclamation. See Note 10.

- 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 13.

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 OCI 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 $1,810 million of regulatory assets and $2,062 million of regulatory liabilities on the Consolidated Balance Sheets at December 31, 2024. See Notes 1 and 3 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, 2024, reported pension assets and liabilities on the Consolidated Balance Sheets and our 2024 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**	**Impact on Pension Expense**
Discount rate (b):		
Increase 1%	$ (231)	$ (11)
Decrease 1%	271	11
EROA:		
Increase 1%	—	(24)
Decrease 1%	—	24

(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, 2024, other postretirement benefit obligation on the Pinnacle West's Consolidated Balance Sheets and our 2024 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**	**Impact on Other Postretirement Benefit Expense**
Discount rate (b):		
Increase 1%	$ (32)	$ (2)
Decrease 1%	38	3
Healthcare cost trend rate (c):		
Increase 1%	12	5
Decrease 1%	(10)	(5)
EROA – pretax:		
Increase 1%	—	(6)
Decrease 1%	—	6

(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 7 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 12 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, 2024 are described further in Note 11.

OTHER ACCOUNTING MATTERS

We adopted new accounting standard, ASU 2023-07, Segment Reporting: Improvements to Reportable Segment Disclosures, on December 31, 2024. We will adopt new accounting standard, ASU 2023-09, Income Taxes: Improvements to Income Tax Disclosures, on December 31, 2025. We are currently evaluating the disclosure impacts of the pending adoption of the new accounting standard, ASU 2024-03, Income Statement Reporting: Expense Disaggregation Disclosures, effective for us on December 31, 2027. See Note 21 for additional information relating to new accounting standards.

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 12 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, 2024, and 2023. If variable interest rates were to increase by 10% from the December 31, 2024, 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, 2024, and 2023 (dollars in millions):

Pinnacle West – Consolidated

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2024	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	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

2023	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
2024	5.46 %	$ 610	6.20 %	$ 625	3.35 %	$ 250
2025	—	—	—	—	1.99 %	800
2026	—	—	—	—	2.55 %	250
2027	—	—	—	—	2.95 %	300
2028	—	—	—	—	—	—
Years thereafter	—	—	4.11 %	164	4.22 %	6,080
Total		$ 610		$ 789		$ 7,680
Fair value		$ 610		$ 789		$ 6,767

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, 2024, and 2023. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2024, and 2023 (dollars in millions):

APS — Consolidated

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

2023	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
2024	5.46 %	$ 533	—	$ —	3.35 %	$ 250
2025	—	—	—	—	3.15 %	300
2026	—	—	—	—	2.55 %	250
2027	—	—	—	—	2.95 %	300
2028	—	—	—	—	—	—
Years thereafter	—	—	4.11 %	164	4.22 %	6,080
Total		$ 533		$ 164		$ 7,180
Fair value		$ 533		$ 164		$ 6,296

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, 2024	December 31, 2023
Mark-to-market of net positions at beginning of year	$ (120)	$ 96
Decrease (increase) in regulatory asset	78	(216)
Mark-to-market of net positions at end of year	$ (42)	$ (120)

The table below shows the fair value of maturities of our energy derivative contracts (dollars in millions) at December 31, 2024, 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	2025	2026	2027	2028	2029	Total Fair Value
Observable prices provided by other external sources	$ (32)	$ 2	$ 3	$ —	$ —	$ (27)
Prices based on unobservable inputs	(6)	(9)	—	—	—	(15)
Total by maturity	$ (38)	$ (7)	$ 3	$ —	$ —	$ (42)

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, 2024 Gain (Loss)		December 31, 2023 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)	$ 9	$ (9)
Natural gas	75	(75)	55	(55)
Total	$ 78	$ (78)	$ 64	$ (64)

(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 15 for a discussion of our credit valuation adjustment policy.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Market and Credit Risks" in 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

	Page
Management's Report on Internal Control over Financial Reporting (Pinnacle West Capital Corporation)	90
Report of Independent Registered Public Accounting Firm (PCAOB ID No. 34)	91
Pinnacle West Consolidated Statements of Income for 2024, 2023 and 2022	95
Pinnacle West Consolidated Statements of Comprehensive Income for 2024, 2023 and 2022	96
Pinnacle West Consolidated Balance Sheets as of December 31, 2024 and 2023	97
Pinnacle West Consolidated Statements of Cash Flows for 2024, 2023 and 2022	99
Pinnacle West Consolidated Statements of Changes in Equity for 2024, 2023 and 2022	100
Management's Report on Internal Control over Financial Reporting (Arizona Public Service Company)	101
Report of Independent Registered Public Accounting Firm (PCAOB ID No. 34)	102
APS Consolidated Statements of Income for 2024, 2023 and 2022	106
APS Consolidated Statements of Comprehensive Income for 2024, 2023 and 2022	107
APS Consolidated Balance Sheets as of December 31, 2024 and 2023	108
APS Consolidated Statements of Cash Flows for 2024, 2023 and 2022	110
APS Consolidated Statements of Changes in Equity for 2024, 2023 and 2022	111
Combined Notes to Consolidated Financial Statements	112
Note 1. Summary of Significant Accounting Policies	112
Note 2. Revenue	122
Note 3. Regulatory Matters	123
Note 4. Income Taxes	138
Note 5. Lines of Credit and Short-Term Borrowings	143
Note 6. Long-Term Debt and Liquidity Matters	145
Note 7. Retirement Plans and Other Postretirement Benefits	150
Note 8. Leases	158
Note 9. Jointly-Owned Facilities	162
Note 10. Commitments and Contingencies	163
Note 11. Asset Retirement Obligations	172
Note 12. Fair Value Measurements	174
Note 13. Common Stock Equity and Earnings Per Share	180
Note 14. Stock-Based Compensation	182
Note 15. Derivative Accounting	185
Note 16. Other Income and Other Expense	189
Note 17. Variable Interest Entities	190
Note 18. Investments in Nuclear Decommissioning Trusts and Other Special Use Funds	192
Note 19. Changes in Accumulated Other Comprehensive Loss	195
Note 20. Sale of Bright Canyon Energy	196
Note 21. New Accounting Standards	197

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 Rules 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 the framework in *Internal Control — Integrated Framework (2013),* our management concluded that our internal control over financial reporting was effective as of December 31, 2024. The effectiveness of our internal control over financial reporting as of December 31, 2024, 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, 2025

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, 2024 and 2023, 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, 2024, 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, 2024, 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, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, 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, 2024, 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 3 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; regulatory assets and liabilities; operating revenues; fuel and purchased power; operations and maintenance expense; and depreciation 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 Regulatory Accounting, specifically the impact of rate regulation on the financial statements, 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 impact of rate regulation on the financial statements 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 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, regulatory orders and filings, and compared to management's recorded regulatory assets and liabilities for completeness.
    - We read the ACC's approved decision regarding the 2022 Retail Rate Case.
    - We obtained the Company's internally prepared memo concluding on the impacts of the ACC's approved decision regarding the 2022 Retail Rate Case on rates and recorded regulatory balances.
    - We read and analyzed the minutes of the Boards of Directors of the Company for discussions of changes in legal, regulatory, or business factors which could impact

management's conclusions with respect to the financial statement impacts of rate regulation.

- We evaluated management's assessment of the probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities based on applicable regulatory orders or precedents set by the ACC under similar circumstances. We read the minutes of the Boards of Directors of the Company for discussions of changes in legal, regulatory, or business factors which could impact management's assessment.

/s/ Deloitte & Touche LLP

Tempe, Arizona
February 25, 2025

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,		
	2024	2023	2022
OPERATING REVENUES (Note 2)	$ 5,124,915	$ 4,695,991	$ 4,324,385
OPERATING EXPENSES			
Fuel and purchased power	1,822,566	1,792,657	1,629,343
Operations and maintenance	1,165,156	1,058,725	987,072
Depreciation and amortization	895,346	794,043	753,195
Taxes other than income taxes	227,395	224,013	220,370
Other expense	2,389	1,913	2,494
Total	4,112,852	3,871,351	3,592,474
OPERATING INCOME	1,012,063	824,640	731,911
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	38,620	53,118	45,263
Pension and other postretirement non-service credits, net (Note 7)	48,870	40,648	98,487
Other income (Note 16)	48,614	33,666	7,916
Other expense (Note 16)	(34,136)	(25,056)	(52,385)
Total	101,968	102,376	99,281
INTEREST EXPENSE			
Interest charges	425,742	374,887	283,569
Allowance for borrowed funds used during construction (Note 1)	(48,270)	(43,564)	(28,030)
Total	377,472	331,323	255,539
INCOME BEFORE INCOME TAXES	736,559	595,693	575,653
INCOME TAXES (Note 4)	110,529	76,912	74,827
NET INCOME	626,030	518,781	500,826
Less: Net income attributable to noncontrolling interests (Note 17)	17,224	17,224	17,224
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 608,806	$ 501,557	$ 483,602
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	113,846	113,442	113,196
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	116,232	113,804	113,416
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Net income attributable to common shareholders — basic	$ 5.35	$ 4.42	$ 4.27
Net income attributable to common shareholders — diluted	$ 5.24	$ 4.41	$ 4.26

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,		
	2024	2023	2022
NET INCOME	$ 626,030	$ 518,781	$ 500,826
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized gain (loss), net of tax benefit (expense) of $(292), $234, and $615	(891)	713	1,873
Pension and other postretirement benefits activity, net of tax benefit (expense) of $(1,073), $801, and $(7,078) (Note 7)	3,093	(2,422)	21,553
Total other comprehensive income (loss)	2,202	(1,709)	23,426
COMPREHENSIVE INCOME	628,232	517,072	524,252
Less: Comprehensive income attributable to noncontrolling interests	17,224	17,224	17,224
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 611,008	$ 499,848	$ 507,028

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

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

	December 31, 2024	December 31, 2023
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 3,838	$ 4,955
Customer and other receivables	525,608	513,892
Accrued unbilled revenues	176,903	167,553
Allowance for doubtful accounts (Note 2)	(24,849)	(22,433)
Materials and supplies (at average cost)	469,022	444,344
Income tax receivable (Note 4)	—	332
Fossil fuel (at average cost)	32,420	49,203
Assets from risk management activities (Note 15)	10,578	6,808
Assets held for sale (Note 20)	—	35,139
Deferred fuel and purchased power regulatory asset (Note 3)	287,597	463,195
Other regulatory assets (Note 3)	133,372	162,562
Other current assets	74,915	101,417
Total current assets	1,689,404	1,926,967
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 12 and 18)	1,282,845	1,201,246
Other special use funds (Notes 12, 17 and 18)	408,357	362,781
Assets from risk management activities (Note 15)	5,980	—
Other assets	115,095	102,845
Total investments and other assets	1,812,277	1,666,872
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9)		
Plant in service and held for future use	25,860,950	24,211,167
Accumulated depreciation and amortization	(9,027,426)	(8,408,040)
Net	16,833,524	15,803,127
Construction work in progress	1,592,659	1,724,004
Palo Verde sale leaseback, net of accumulated depreciation of $268,894 and $264,624 (Note 17)	82,556	86,426
Intangible assets, net of accumulated amortization of $925,880 and $885,505	591,310	267,110
Nuclear fuel, net of accumulated amortization of $115,894 and $118,074	97,850	99,490
Total property, plant and equipment	19,197,899	17,980,157
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3, 4 and 7)	1,389,489	1,390,279
Operating lease right-of-use assets (Note 8)	1,605,463	1,309,975
Assets for pension and other postretirement benefits (Note 7)	342,102	323,438
Other	66,126	63,465
Total deferred debits	3,403,180	3,087,157
TOTAL ASSETS	$ 26,102,760	$ 24,661,153

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

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

	December 31,	
	2024	**2023**
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 485,426	$ 442,455
Accrued taxes	175,863	166,833
Accrued interest	81,799	72,916
Common dividends payable	106,592	99,813
Short-term borrowings (Note 5)	568,450	609,500
Current maturities of long-term debt (Note 6)	800,000	875,000
Customer deposits	44,345	42,037
Liabilities from risk management activities (Note 15)	52,340	80,913
Liabilities for asset retirements (Note 11)	50,009	28,550
Operating lease liabilities (Note 8)	100,367	67,883
Regulatory liabilities (Note 3)	206,955	209,923
Other current liabilities	171,651	193,524
Total current liabilities	2,843,797	2,889,347
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 6)	8,058,648	7,540,622
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	2,444,473	2,416,480
Regulatory liabilities (Notes 1, 3, 4 and 7)	1,855,278	1,965,865
Liabilities for asset retirements (Note 11)	1,096,577	937,451
Liabilities for pension benefits (Note 7)	139,317	112,702
Liabilities from risk management activities (Note 15)	9,446	42,975
Customer advances	569,343	533,580
Coal mine reclamation	171,483	184,007
Deferred investment tax credit	249,490	257,743
Unrecognized tax benefits (Note 4)	44,233	33,861
Operating lease liabilities (Note 8)	1,520,877	1,210,189
Other	242,320	251,469
Total deferred credits and other	8,342,837	7,946,322
COMMITMENTS AND CONTINGENCIES (Note 10)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 119,143,782 and 113,537,689 issued at respective dates	3,121,617	2,752,676
Treasury stock at cost; 46,968 and 113,272 shares at respective dates	(3,323)	(8,185)
Total common stock	3,118,294	2,744,491
Retained earnings	3,666,959	3,466,317
Accumulated other comprehensive loss (Note 19)	(30,942)	(33,144)
Total shareholders' equity	6,754,311	6,177,664
Noncontrolling interests (Note 17)	103,167	107,198
Total equity	6,857,478	6,284,862
TOTAL LIABILITIES AND EQUITY	$ 26,102,760	$ 24,661,153

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,		
	2024	2023	2022
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 626,030	$ 518,781	$ 500,826
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	956,184	854,136	817,814
Deferred fuel and purchased power	(250,288)	(549,877)	(291,992)
Deferred fuel and purchased power amortization	425,886	547,243	219,579
Allowance for equity funds used during construction	(38,620)	(53,118)	(45,263)
Deferred income taxes	(20,923)	(24,310)	43,202
Deferred investment tax credit	(8,253)	77,065	(5,893)
Change in derivative instruments fair value	—	(777)	777
Stock compensation	23,532	17,341	15,942
Changes in current assets and liabilities:			
Customer and other receivables	(12,696)	(61,983)	(63,869)
Accrued unbilled revenues	(9,350)	(2,789)	(30,784)
Materials, supplies and fossil fuel	(7,895)	(42,911)	(83,469)
Income tax receivable	332	13,754	(6,572)
Other current assets	(50,225)	(19,550)	76,089
Accounts payable	(7,214)	(75,623)	90,076
Accrued taxes	9,030	2,393	(4,205)
Other current liabilities	47,329	40,510	(1,856)
Change in long-term regulatory assets	43,305	53,112	12,432
Change in long-term regulatory liabilities	9,416	28,495	(332,470)
Change in other long-term assets	(132,563)	(195,598)	159,030
Change in operating lease assets	98,214	90,525	105,359
Change in other long-term liabilities	24,794	63,080	170,359
Change in operating lease liabilities	(93,214)	(65,779)	(103,671)
Net cash provided by operating activities	1,609,823	1,207,697	1,241,441
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(2,249,195)	(1,846,370)	(1,707,490)
Contributions in aid of construction	311,358	180,866	137,436
Proceeds from sale relating to BCE	84,322	23,400	—
Allowance for borrowed funds used during construction	(48,270)	(43,564)	(28,030)
Proceeds from nuclear decommissioning trust sales and other special use funds	1,686,094	1,679,722	1,207,713
Investment in nuclear decommissioning trust and other special use funds	(1,709,526)	(1,681,845)	(1,212,063)
Other	(8,413)	(6,458)	(15,612)
Net cash used for investing activities	(1,933,630)	(1,694,249)	(1,618,046)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	1,313,229	689,349	875,537
Repayment of long-term debt	(875,000)	(32,740)	(150,000)
Short-term borrowings and (repayments) — net	(241,050)	241,900	48,720
Short-term debt borrowings under term loan facility	550,000	—	—
Short-term debt repayments under term loan facility	(350,000)	—	—
Dividends paid on common stock	(394,663)	(386,486)	(378,881)
Common stock equity issuance and purchases — net	341,429	(4,093)	(2,653)
Capital activities by noncontrolling interests	(21,255)	(21,255)	(21,255)
Net cash provided by financing activities	322,690	486,675	371,468
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1,117)	123	(5,137)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	4,955	4,832	9,969
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 3,838	$ 4,955	$ 4,832

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, 2021	113,014,528	$2,702,743	(87,608)	$ (6,401)	$3,264,719	$ (54,861)	$ 115,260	$ 6,021,460
Net income		—		—	483,602	—	17,224	500,826
Other comprehensive income		—		—	—	23,426	—	23,426
Dividends on common stock ($3.43 per share)		—		—	(387,975)	—	—	(387,975)
Issuance of common stock	232,661	21,996		—	—	—	—	21,996
Purchase of treasury stock (a)		—	(77,152)	(5,152)	—	—	—	(5,152)
Reissuance of treasury stock for stock-based compensation and other		—	91,147	6,548	—	—	—	6,548
Capital activities by noncontrolling interests		—		—	—	—	(21,255)	(21,255)
Other		1		—	1	—	—	2
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

(a) Primarily represents shares of common stock withheld from certain stock awards for tax purposes.

(b) See Note 13 for information related to our equity forward sale agreements that were executed in February 2024 and November 2024. As of December 31, 2024, 5,377,115 shares of common stock have been issued as part of these agreements.

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 Rules 13a-15(f), for Arizona Public Service Company. 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 the framework in *Internal Control — Integrated Framework (2013),* our management concluded that our internal control over financial reporting was effective as of December 31, 2024. The effectiveness of our internal control over financial reporting as of December 31, 2024, 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, 2025

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, 2024 and 2023, 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, 2024, 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, 2024, 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, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, 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, 2024, 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 3 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; regulatory assets and liabilities; operating revenues; fuel and purchased power; operations and maintenance expense; and depreciation 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 Regulatory Accounting, specifically the impact of rate regulation on the financial statements, 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 impact of rate regulation on the financial statements 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, regulatory orders and filings, and compared to management's recorded regulatory assets and liabilities for completeness.
    - We read the ACC's approved decision regarding the 2022 Retail Rate Case.
    - We obtained the Company's internally prepared memo concluding on the impacts of the ACC's approved decision regarding the 2022 Retail Rate Case on rates and recorded regulatory balances.
    - We read and analyzed the minutes of the Boards of Directors of the Company for discussions of changes in legal, regulatory, or business factors which could impact

management's conclusions with respect to the financial statement impacts of rate regulation.

- We evaluated management's assessment of the probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities based on applicable regulatory orders or precedents set by the ACC under similar circumstances. We read the minutes of the Boards of Directors of the Company for discussions of changes in legal, regulatory, or business factors which could impact management's assessment.

/s/ Deloitte & Touche LLP

Tempe, Arizona
February 25, 2025

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,		
	2024	**2023**	**2022**
OPERATING REVENUES (Note 2)	$ 5,124,915	$ 4,695,991	$ 4,324,385
OPERATING EXPENSES			
Fuel and purchased power	1,822,566	1,792,657	1,629,343
Operations and maintenance	1,158,634	1,043,570	974,220
Depreciation and amortization	895,171	793,958	753,110
Taxes other than income taxes	227,307	223,962	220,277
Other expense	2,389	1,913	2,494
Total	4,106,067	3,856,060	3,579,444
OPERATING INCOME	1,018,848	839,931	744,941
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	38,620	53,118	45,263
Pension and other postretirement non-service credits, net (Note 7)	49,489	41,577	98,945
Other income (Note 16)	21,094	27,072	5,888
Other expense (Note 16)	(29,698)	(18,264)	(26,108)
Total	79,505	103,503	123,988
INTEREST EXPENSE			
Interest charges	360,481	323,719	262,815
Allowance for borrowed funds used during construction (Note 1)	(48,270)	(39,030)	(26,839)
Total	312,211	284,689	235,976
INCOME BEFORE INCOME TAXES	786,142	658,745	632,953
INCOME TAXES (Note 4)	126,993	94,184	90,800
NET INCOME	659,149	564,561	542,153
Less: Net income attributable to noncontrolling interests (Note 17)	17,224	17,224	17,224
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 641,925	$ 547,337	$ 524,929

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,		
	2024	2023	2022
NET INCOME	$ 659,149	$ 564,561	$ 542,153
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Pension and other postretirement benefits activity, net of tax benefit (expense) of $(1,022), $536, and $(6,332) (Note 7)	3,103	(1,623)	19,284
Total other comprehensive income (loss)	3,103	(1,623)	19,284
COMPREHENSIVE INCOME	662,252	562,938	561,437
Less: Comprehensive income attributable to noncontrolling interests	17,224	17,224	17,224
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 645,028	$ 545,714	$ 544,213

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

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

	December 31,	
	2024	2023
ASSETS		
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9)		
Plant in service and held for future use	$ 25,860,068	$ 24,207,706
Accumulated depreciation and amortization	(9,026,544)	(8,404,721)
Net	16,833,524	15,802,985
Construction work in progress	1,592,659	1,724,004
Palo Verde sale leaseback, net of accumulated depreciation of $268,894 and $264,624 (Note 17)	82,556	86,426
Intangible assets, net of accumulated amortization of $925,880 and $884,371	591,154	266,955
Nuclear fuel, net of accumulated amortization of $115,894 and $118,074	97,850	99,490
Total property, plant and equipment	19,197,743	17,979,860
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 12 and 18)	1,282,845	1,201,246
Other special use funds (Notes 12 and 18)	374,156	362,781
Assets from risk management activities (Note 15)	5,980	—
Other assets	49,673	43,625
Total investments and other assets	1,712,654	1,607,652
CURRENT ASSETS		
Cash and cash equivalents	3,815	4,549
Customer and other receivables	522,886	510,296
Accrued unbilled revenues	176,903	167,553
Allowance for doubtful accounts (Note 2)	(24,849)	(22,433)
Materials and supplies (at average cost)	469,022	444,344
Fossil fuel (at average cost)	32,420	49,203
Income tax receivable (Note 4)	5,463	—
Assets from risk management activities (Note 15)	10,578	6,808
Deferred fuel and purchased power regulatory asset (Note 3)	287,597	463,195
Other regulatory assets (Note 3)	133,372	162,562
Other current assets	65,754	64,311
Total current assets	1,682,961	1,850,388
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3, 4 and 7)	1,389,489	1,390,279
Operating lease right-of-use assets (Note 8)	1,604,324	1,308,611
Assets for pension and other postretirement benefits (Note 7)	335,458	316,606
Other	65,606	63,059
Total deferred debits	3,394,877	3,078,555
TOTAL ASSETS	$ 25,988,235	$ 24,516,455

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

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

	December 31,	
	2024	**2023**
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	4,116,696	3,321,696
Retained earnings	3,992,423	3,759,299
Accumulated other comprehensive loss (Note 19)	(14,116)	(17,219)
Total shareholder equity	8,273,165	7,241,938
Noncontrolling interests (Note 17)	103,167	107,198
Total equity	8,376,332	7,349,136
Long-term debt less current maturities (Note 6)	7,190,878	7,041,891
Total capitalization	15,567,210	14,391,027
CURRENT LIABILITIES		
Short-term borrowings (Note 5)	339,900	532,850
Current maturities of long-term debt (Note 6)	300,000	250,000
Accounts payable	481,955	433,229
Accrued taxes	181,698	162,288
Accrued interest	79,308	72,548
Common dividends payable	107,200	99,800
Customer deposits	44,345	42,037
Liabilities from risk management activities (Note 15)	52,340	80,913
Liabilities for asset retirements (Note 11)	50,009	28,550
Operating lease liabilities (Note 8)	100,229	67,608
Regulatory liabilities (Note 3)	206,955	209,923
Other current liabilities	177,019	211,773
Total current liabilities	2,120,958	2,191,519
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	2,419,937	2,431,697
Regulatory liabilities (Notes 1, 3, 4 and 7)	1,855,278	1,965,865
Liabilities for asset retirements (Note 11)	1,096,577	937,451
Liabilities for pension benefits (Note 7)	134,855	106,215
Liabilities from risk management activities (Note 15)	9,446	42,975
Customer advances	569,343	533,580
Coal mine reclamation	171,483	184,007
Deferred investment tax credit	249,490	257,743
Unrecognized tax benefits (Note 4)	48,725	33,861
Operating lease liabilities (Note 8)	1,519,683	1,208,857
Other	225,250	231,658
Total deferred credits and other	8,300,067	7,933,909
COMMITMENTS AND CONTINGENCIES (Note 10)		
TOTAL LIABILITIES AND EQUITY	$ 25,988,235	$ 24,516,455

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,		
	2024	2023	2022
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 659,149	$ 564,561	$ 542,153
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	956,009	854,051	817,729
Deferred fuel and purchased power	(250,288)	(549,877)	(291,992)
Deferred fuel and purchased power amortization	425,886	547,243	219,579
Allowance for equity funds used during construction	(38,620)	(53,118)	(45,263)
Deferred income taxes	(56,461)	(10,314)	(6,817)
Deferred investment tax credit	(8,253)	77,065	(5,893)
Changes in current assets and liabilities:			
Customer and other receivables	(13,570)	(62,716)	(60,930)
Accrued unbilled revenues	(9,350)	(2,789)	(30,784)
Materials, supplies and fossil fuel	(7,895)	(42,911)	(83,469)
Income tax receivable	(5,463)	1,102	9,654
Other current assets	(14,704)	(20,243)	59,970
Accounts payable	(2,500)	(70,622)	79,492
Accrued taxes	19,410	5,542	4,734
Other current liabilities	31,982	62,212	1,190
Change in long-term regulatory assets	43,305	53,112	12,432
Change in long-term regulatory liabilities	9,416	28,495	(332,470)
Change in other long-term assets	(159,940)	(188,483)	170,587
Change in operating lease assets	97,989	90,234	105,058
Change in other long-term liabilities	27,202	58,574	168,503
Change in operating lease liabilities	(93,076)	(65,482)	(103,361)
Net cash provided by operating activities	1,610,228	1,275,636	1,230,102
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(2,249,195)	(1,825,585)	(1,655,051)
Contributions in aid of construction	311,358	180,866	137,436
Allowance for borrowed funds used during construction	(48,270)	(39,030)	(26,839)
Proceeds from nuclear decommissioning trust sales and other special use funds	1,686,094	1,679,722	1,207,713
Investment in nuclear decommissioning trust and other special use funds	(1,684,526)	(1,681,845)	(1,212,063)
Other	(1,660)	(1,397)	(727)
Net cash used for investing activities	(1,986,199)	(1,687,269)	(1,549,531)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	445,842	496,025	524,852
Repayment of long-term debt	(250,000)	—	—
Short-term borrowings and (repayments) — net	(192,950)	180,970	46,300
Short-term debt borrowings under term loan facility	350,000	—	—
Short-term debt repayments under term loan facility	(350,000)	—	—
Dividends paid on common stock	(401,400)	(393,600)	(385,800)
Equity infusion from Pinnacle West	795,000	150,000	150,000
Capital activities of noncontrolling interests	(21,255)	(21,255)	(21,255)
Net cash provided by financing activities	375,237	412,140	314,097
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(734)	507	(5,332)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	4,549	4,042	9,374
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 3,815	$ 4,549	$ 4,042

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, 2021	71,264,947	$ 178,162	$3,021,696	$3,470,235	$ (34,880)	$ 115,260	$ 6,750,473
Equity infusion from Pinnacle West		—	150,000	—	—	—	150,000
Net income		—	—	524,929	—	17,224	542,153
Other comprehensive income		—	—	—	19,284	—	19,284
Dividends on common stock		—	—	(387,700)	—	—	(387,700)
Capital activities by noncontrolling interests		—	—	—	—	(21,255)	(21,255)
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

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 a 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 is a wholly-owned subsidiary that was created in September 2023 to hold certain investments in wind and transmission joint projects. See Note 20 for more information on PNW Power.

BCE was a Pinnacle West subsidiary that was formed in 2014. On August 4, 2023, Pinnacle West entered into a purchase and sale agreement pursuant to which all of our equity interest in BCE was sold. The sale was completed on January 12, 2024. See Note 20 for more information relating to the sale of BCE.

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 our former subsidiary BCE until its sale. Pinnacle West's Consolidated Financial Statements also include the accounts of a VIE relating to a Captive Insurance Cell ("Captive"). APS's Consolidated Financial Statements include the accounts of APS and certain VIEs relating to the Palo Verde sale leaseback. Intercompany accounts and transactions between the consolidated companies have been eliminated.

We consolidate Variable Interest Entities (each a "VIE") 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 certain VIE lessor trusts relating to the Palo Verde sale leaseback, and therefore APS consolidates these entities. 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 17 for additional information.

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America ("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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 3 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 2 and 3 for additional information.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 2 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, 2024, and 2023 Consolidated Balance Sheets is composed of the following (dollars in thousands):

Property, Plant and Equipment:	2024	2023
Generation	$ 11,111,915	$ 10,446,291
Transmission	4,135,970	3,773,253
Distribution	9,016,843	8,448,293
General plant	1,596,222	1,543,330
Plant in service and held for future use	25,860,950	24,211,167
Accumulated depreciation and amortization	(9,027,426)	(8,408,040)
Net	16,833,524	15,803,127
Construction work in progress	1,592,659	1,724,004
Palo Verde sale leaseback, net of accumulated depreciation	82,556	86,426
Intangible assets, net of accumulated amortization	591,310	267,110
Nuclear fuel, net of accumulated amortization	97,850	99,490
Total property, plant and equipment	$ 19,197,899	$ 17,980,157

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 11 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, 2024, were as follows:

- Steam generation — 11 years;
- Nuclear plant — 25 years;
- Other generation — 18 years;
- Transmission — 38 years;
- Distribution — 33 years; and
- General plant — 7 years.

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. Depreciation expense was $723 million in 2024, $669 million in 2023, and $632 million in 2022. For the years 2022 through 2024, the depreciation rates ranged from a low of 1.37% to a high of 12.15%. The weighted-average depreciation rate was 3.13% in 2024, 2.98% in 2023, and 3.03% in 2022.

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 11 for further information on Asset Retirement Obligations.

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 6.23% for 2024, 6.29% for 2023, and 5.75% for 2022. APS compounds AFUDC semi-annually and ceases to accrue AFUDC when construction work is completed and the property is placed in service.

On June 30, 2020, FERC issued an order granting a waiver request related to the existing AFUDC rate calculation beginning March 1, 2020, through February 28, 2021. On February 23, 2021, this waiver was extended until September 30, 2021. On September 21, 2021, it was further extended until March 31, 2022. The order provided a simplified approach that companies may elect to implement in order to minimize the significant distorted effect on the AFUDC formula resulting from increased short-term debt financing during the COVID-19 pandemic. APS adopted this simplified approach to computing the AFUDC composite rate by using a simple average of the actual historical short-term debt balances for 2019, instead of current period short-term debt balances, and left all other aspects of the AFUDC formula composite rate calculation unchanged. This change impacted the AFUDC composite rate in 2021 and for the three-month period ended March 31, 2022. Furthermore, the change in the composite rate calculation did not impact our accounting treatment for these costs. The change did not have a material impact on our financial statements.

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 short-term 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 6 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 12 for additional information about fair value measurements.

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 15 for additional information about our derivative instruments.

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 liability may be in excess of or less than the amount provided. 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, 2024, no IBNR reserve relating to our captive insurance cell has been recorded. See Note 17.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 7 for additional information on pension and other postretirement benefits.

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 2024. See Note 10 for information on spent nuclear fuel disposal costs.

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 4 for additional discussion.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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,		
	2024	2023	2022
Cash paid during the period for:			
Income taxes, net of refunds	$ 133,968	$ 8,788	$ 46,227
Interest, net of amounts capitalized	360,349	310,996	245,271
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 257,494	$ 206,269	$ 114,999
Dividends accrued but not yet paid	106,592	99,813	97,895
BCE Sale non-cash consideration (Note 20)	—	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,		
	2024	2023	2022
Cash paid during the period for:			
Income taxes, net of refunds	$ 179,013	$ 21,734	$ 95,985
Interest, net of amounts capitalized	299,799	267,261	227,159
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 257,494	$ 206,269	$ 116,533
Dividends accrued but not yet paid	107,200	99,800	97,900

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 $136 million in 2024, $90 million in 2023, and $84 million in 2022. Estimated amortization expense on existing intangible assets over the next five years is $106 million in 2025, $77 million in 2026, $43 million in 2027, $25 million in 2028, and $14 million in 2029. At December 31, 2024, the weighted-average remaining amortization period for intangible assets was 5 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 20% ownership and no significant influence).

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 20% 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 12 and 18 for more information on these investments.

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 purchased power agreement 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 3. We also may enter into lease agreements related to vehicles, office space, land, and other equipment. See Note 8 for information on our lease agreements.

Business Segments

Pinnacle West's 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 segment activities are conducted through our wholly-owned subsidiary, APS. All other operating segment activities are insignificant to Pinnacle West.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For segment reporting purposes, Pinnacle West's Chief Executive Officer performs the function of chief operating decision maker ("CODM"). The 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, the 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, assets, and other reportable segment items, see the APS's Consolidated Income Statements, APS Consolidated Balance Sheets, and APS Consolidated Statements of Cash Flows. The following tables reconcile our reportable segment's revenues, significant expenses, net income, and assets to the Pinnacle West Consolidated amounts (dollars in millions):

	Year Ended December 31,								
	2024			2023			2022		
	Regulated Electricity Segment	Other	Pinnacle West Consolidated	Regulated Electricity Segment	Other	Pinnacle West Consolidated	Regulated Electricity Segment	Other	Pinnacle West Consolidated
Operating Revenues	$ 5,125	$ —	$ 5,125	$ 4,696	$ —	$ 4,696	$ 4,324	$ —	$ 4,324
Fuel & Purchase Power	(1,823)	—	(1,823)	(1,793)	—	(1,793)	(1,629)	—	(1,629)
Operations & Maintenance	(1,159)	(6)	(1,165)	(1,044)	(15)	(1,059)	(974)	(13)	(987)
Depreciation & Amortization	(895)	—	(895)	(794)	—	(794)	(753)	—	(753)
Taxes other than income taxes	(227)	—	(227)	(224)	—	(224)	(220)	—	(220)
Pension and other postretirement non-service credits, net	49	—	49	42	(1)	41	99	(1)	98
Other income and expenses, net (a)	28	22	50	60	—	60	22	(23)	(1)
Interest expense and costs	(312)	(65)	(377)	(285)	(46)	(331)	(236)	(20)	(256)
Income Taxes	(127)	16	(111)	(94)	17	(77)	(91)	16	(75)
Less: income related to noncontrolling interest	(17)	—	(17)	(17)	—	(17)	(17)	—	(17)
Net Income (loss)	$ 642	$ (33)	$ 609	$ 547	$ (45)	$ 502	$ 525	$ (41)	$ 484

(a) See Note 16 for additional details regarding other income and other expenses. Other income includes allowance for equity funds used during construction, see the APS Consolidated Income Statements.

	December 31, 2024			December 31, 2023		
	Regulated Electricity Segment	Other	PNW Consolidated	Regulated Electricity Segment	Other	PNW Consolidated
Total Assets	$ 25,988	$ 115	$ 26,103	$ 24,516	$ 145	$ 24,661

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Preferred Stock

At December 31, 2024, 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. Revenue

Sources of Revenue

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

	Year Ended December 31,		
	2024	2023	2022
Retail Electric Service			
Residential	$ 2,562,822	$ 2,289,196	$ 2,046,111
Non-Residential	2,334,925	2,048,416	1,767,616
Wholesale Energy Sales	96,857	208,985	383,126
Transmission Services for Others	119,038	138,631	116,628
Other Sources	11,273	10,763	10,904
Total Operating Revenues	$ 5,124,915	$ 4,695,991	$ 4,324,385

Retail Electric Revenue. All of Pinnacle West's retail electric revenue is 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.

Wholesale Energy Sales and Transmission Services for Others. Revenues from wholesale energy sales and transmission services for others represent energy and transmission sales to wholesale customers. These activities primarily consist of managing fuel and purchased power risks 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, 2024, 2023 and 2022 were $5,073 million, $4,651 million, and $4,302 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, 2024, 2023, and 2022 our revenues that do not qualify as revenue from contracts with customers were $52 million, $45 million, and $22 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 3 for a discussion of our regulatory cost recovery mechanisms.

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. 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,		
	2024	2023	2022
Balance at beginning of period	$ 22,433	$ 23,778	$ 25,354
Bad debt expense	35,799	23,399	17,006
Actual write-offs	(33,383)	(24,744)	(18,582)
Balance at end of period	$ 24,849	$ 22,433	$ 23,778

3. Regulatory Matters

APS expects to file an application with the ACC for its next general rate case mid-year 2025 and is continuing to evaluate the timing of such filing.

2022 Retail Rate Case

APS filed an application with the ACC on October 28, 2022 (the "2022 Rate Case") seeking an increase in annual retail base rates.

On January 25, 2024, an Administrative Law Judge issued a Recommended Opinion and Order ("ROO") in the 2022 Rate Case, as corrected on February 6, 2024 (the "2022 Rate Case ROO"). The 2022 Rate Case ROO recommended, among other things, (i) a $523.1 million increase in the annual base rate 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 4.36%, (v) 12 months of post-

test year plant and the inclusion of the Four Corners Effluent Limitations Guideline ("ELG") project, (vi) the approval of APS's System Reliability Benefit ("SRB") proposal with certain procedural and other modifications, (vii) no additional Coal Community Transition ("CCT") funding, (viii) a 5.0% return on the prepaid pension asset and a return of 5.35% on the OPEB liability, and (ix) no disallowances on APS's coal contracts.

The 2022 Rate Case ROO also recommended a number of changes to existing adjustors, including (i) the approval of modified DSM performance incentives and the requested DSM transfer to base rates, (ii) the retention of $1.9 million of Renewable Energy Adjustment Charge ("REAC") in the adjustor rather than base rates, (iii) a partial transfer of $27.1 million of LFCR funds to base rates, and (iv) the adoption of an increase in the annual PSA cap to $0.006/kWh.

On February 22, 2024, the ACC approved a number of amendments to the 2022 Rate Case ROO 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 all-source request for proposal ("ASRFP"), and (viii) recovery of all DSM costs through the DSM Adjustment Charge ("DSMAC") rather than through base rates.

The ACC's decision results in an expected total net annual revenue increase for APS of approximately $253.4 million and a roughly 8% increase to the typical residential customer's bill. 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 CCT funding. On April 15, 2024, the ACC granted, in part, the rehearing applications of the Attorney General, Arizona Solar Energy Industries Association, Solar Energy Industries Association, 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. 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 Commission's December 17, 2024 decision on the rehearing. The Commission has taken no action on these requests. In addition, each of these parties have subsequently filed notices of appeal to the Arizona Court of Appeals seeking review of the Commission's decisions regarding the GAC and on rehearing. APS cannot predict the outcome of these proceedings.

2019 Retail Rate Case

On October 31, 2019, APS filed an application with the ACC for an annual increase in retail base rates (the "2019 Rate Case"). On August 2, 2021, an Administrative Law Judge issued a ROO in the 2019 Rate Case (the "2019 Rate Case ROO") and issued corrections on September 10 and September 20, 2021.

On November 2, 2021, the ACC approved the 2019 Rate Case ROO, with various amendments, that resulted in, among other things, (i) a return on equity of 8.70%, which included a 20 basis points penalty; (ii) the recovery of the deferral and rate base effects of the operating costs and construction of the Four Corners selective catalytic reduction ("SCR") project, with the exception of $215.5 million (see "Four Corners SCR Cost Recovery" below); (iii) the CCT plan including the following components: (a) a payment of $1 million to the Hopi Tribe within 60 days of the 2019 Rate Case decision, (b) a payment of $10 million over three years to the Navajo Nation, (c) a payment of $0.5 million to the Navajo County communities within 60 days of the 2019 Rate Case decision, (d) up to $1.25 million for electrification of homes and businesses on the Hopi reservation, and (e) up to $1.25 million for the electrification of homes and businesses on the Navajo Nation reservation; and (iv) a change in the residential on-peak time-of-use period from 3 p.m. to 8 p.m. to 4 p.m. to 7 p.m. Monday through Friday, excluding holidays. The 2019 Rate Case ROO, as amended, resulted in a total annual revenue decrease for APS of $4.8 million, excluding temporary payments and expenditures, under the CCT plan.

Consistent with the 2019 Rate Case decision, APS completed the following payments that are being recovered through rates related to the CCT: (i) $10 million to the Navajo Nation; (ii) $0.5 million to the Navajo County communities; and (iii) $1 million to the Hopi Tribe. Consistent with APS's commitment to the impacted communities, APS has also completed the following payments: (i) $1.5 million to the Navajo Nation for CCT; (ii) $1.1 million to the Navajo County communities for CCT and economic development; and (iii) $1.25 million to the Hopi Tribe for CCT and economic development. The ACC also authorized $1.25 million to be spent for electrification of homes and businesses on each of the Navajo Nation and Hopi reservations. Expenditure of the recoverable funds for electrification of homes and businesses on the Navajo Nation and the Hopi reservations is contingent upon completion of a census of the unelectrified homes and businesses in each that are also within APS service territory. The census work was completed in November 2022 and disbursement of the funds for electrification of homes and businesses is planned to be finalized after discussions with the Navajo Nation and the Hopi Tribe are completed. On February 22, 2024, the ACC voted to not approve any further CCT funding.

APS filed a Notice of Direct Appeal to the Arizona Court of Appeals on December 17, 2021 requesting review of certain aspects of the 2019 Rate Case. On March 6, 2023, the Court issued its opinion in this matter, affirming in part and reversing in part the ACC's decision in the 2019 Rate Case. The Court vacated the 20 basis points penalty included in the ACC's allowed return on equity, as the Court determined the use of customer service metrics to justify the reduction exceeded the ACC's ratemaking authority. Additionally, the Court vacated the disallowance of $215.5 million of APS's Four Corners SCR investment. The Court remanded the issue to the ACC for further proceedings.

On June 14, 2023, APS and the ACC Legal Division filed a joint resolution with the ACC to allow recovery of the $215.5 million in costs related to the installation of the Four Corners SCR, a reversal of the 20 basis points reduction to APS's return on equity from 8.9% to 8.7% as a result of the 2019 Rate Case decision, and recovery of $59.6 million in revenue lost by APS between December 2021 and June 20, 2023. On June 21, 2023, the ACC approved the joint resolution and proposals therein for recovery through

the Court Resolution Surcharge ("CRS") mechanism, which became effective on July 1, 2023. See "Court Resolution Surcharge" below for more information.

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 allows regulated utilities to propose formula rate plans in future rate cases. Proposed plans must be based on a historical test year, include an annual update with a true-up and an earnings test to ensure a utility earns within a 20 basis points band of its authorized return on equity. Proposed plans should also include an annual meeting and challenge periods for stakeholder feedback. Utilities that implement formula rates also must file a full rate case at least every five years unless an alternate schedule is set by the ACC. 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 Retail Rate Case" above for modifications of adjustment mechanisms in the 2022 Rate Case.

Renewable Energy Standard. In 2006, the ACC approved the RES. 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.

In June 2021, the ACC adopted a clean energy rules package which would require APS to meet certain clean energy standards and technology procurement mandates, obtain approval for its action plan included in its Integrated Resource Plan ("IRP"), and seek cost recovery in a rate process. Since the adopted clean energy rules differed substantially from the original ROO, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider ASRFP requirements and the IRP process. See "Energy Modernization Plan" below for more information.

On July 1, 2021, APS filed its 2022 RES Implementation Plan and proposed a budget of approximately $93.1 million. APS filed an amended 2022 RES Implementation Plan on December 9, 2021, with a proposed budget of $100.5 million. This budget included funding for programs to comply with the decision in the 2019 Rate Case, including the ACC authorizing spending $20 million to $30 million in capital costs for the continuation of the APS Solar Communities program each year for a period of three years from the effective date of 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 2022. On May 18, 2022, the ACC approved the 2022

RES Implementation Plan, including an amendment requiring a stakeholder working group convene to develop a community solar program for the ACC's consideration at a future date.

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. 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 2023. The ACC has not yet ruled on the 2024 RES Implementation Plan. APS cannot predict the outcome of this proceeding.

On July 1, 2024, APS filed its 2025 RES Implementation Plan and proposed a budget of approximately $92.7 million. 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 2024. The ACC has not yet ruled on the 2025 RES Implementation Plan. APS cannot predict the outcome of this proceeding.

On June 14, 2021, APS filed an application for approval of its Green Power Partners Program ("GPP"). On September 1, 2021, the ACC approved the application. On June 28, 2024, APS filed an application for approval of modifications to the GPP and requested a renewable generation renewable energy credits waiver. The ACC has not yet ruled on the GPP application. APS cannot predict the outcome of this proceeding.

Demand Side Management Adjustor Charge. The ACC Electric Energy Efficiency Standards require APS to submit a DSM Implementation Plan annually 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 December 17, 2021, APS filed its 2022 DSM Implementation Plan in accordance with an extension granted in 2021. The 2022 DSM Plan requested a budget of $78.4 million and represents an increase of approximately $14 million in DSM spending above 2021. On November 10, 2022, the ACC approved the 2022 DSM Implementation Plan, including a proposed performance incentive.

On June 1, 2022, APS filed its 2023 Transportation Electrification Plan ("2023 TE Plan"). The 2023 TE Plan detailed APS's efforts to support transportation electrification in Arizona, including the Take Charge AZ Pilot Program and customer education and outreach related to transportation electrification. Subsequently, APS filed an amended 2023 TE Plan on November 30, 2022, that included a request for a $5 million budget. On December 12, 2023, the ACC approved the 2023 TE Plan without including the

Take Charge AZ Program and its budget going forward, but allowed APS to complete projects already underway. Additionally, the ACC discontinued the residential EV SmartCharger rebate and approved modifications to the EV rate plan.

On November 30, 2022, APS filed its 2023 DSM Implementation Plan, which requested a budget of $88 million. On May 31, 2023, APS filed an amended 2023 DSM Implementation Plan. The amended plan maintained the originally proposed budget of $88 million. 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 TE Implementation Plan. On April 26, 2024, APS filed an amendment to the 2024 DSM Implementation Plan. The amended 2024 DSM Implementation Plan includes an updated budget of $90.9 million to reflect removal of incentive funds for the Level 2 Smart Charger rebate within the EV Charging Demand Management Pilot, an update on the performance incentive calculation, and the withdrawal of tranches two and three of the residential battery pilot. The ACC has not yet ruled on the amended 2024 DSM Implementation Plan. In a letter filed May 31, 2024, APS said it would not file a 2025 DSM Implementation Plan pending ACC review of the amended 2024 DSM Implementation Plan. APS cannot predict the outcome of this proceeding.

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 the 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the changes in the deferred fuel and purchased power regulatory asset for 2024 and 2023 (dollars in thousands):

	Year Ended December 31,	
	2024	2023
Balance at beginning of period	$ 463,195	$ 460,561
Deferred fuel and purchased power costs	250,288	549,877
Amounts charged to customers	(425,886)	(547,243)
Balance at end of period	$ 287,597	$ 463,195

On November 30, 2021, APS filed its PSA rate for the PSA year beginning February 1, 2022. That rate was $0.007544 per kWh, which consisted of a forward component of $(0.004842) per kWh and a historical component of $0.012386 per kWh. The 2022 PSA rate was a $0.004 per kWh increase compared to the 2021 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. These rates went into effect as filed on February 1, 2022.

On April 1, 2022, the ACC filed a final report of its third-party audit findings regarding APS's fuel and purchased power costs for the period January 2019 through January 2021. The report contained an in-depth review of APS's fuel and purchased power contracts, its monthly fuel accounting activities, its forecasting and dispatching procedures, and its monthly PSA filings, among other fuel-related activities. The report found that APS's fuel processing accounting practices, dispatching procedures, and procedures for hedging activity were reasonable and appropriate. The report included several recommendations for the ACC's consideration, including review of current contracts, maintenance schedules, and certain changes and improvements to the schedules in APS's monthly PSA filings. On December 27, 2022, ACC Staff filed a proposed order supporting adoption of the recommendations in the third-party audit report, and the ACC approved the proposed order on February 22, 2023.

On November 30, 2022, APS filed its PSA rate for the PSA year beginning February 1, 2023. In this filing, APS also requested that one of three different options be adopted to address the growing undercollected PSA balance. On February 23, 2023, the ACC approved an overall PSA rate of $0.019074 per kWh, which consisted of a forward component of $(0.005527) per kWh, a historical component of $0.013071 per kWh and a transition component of $0.011530 per kWh, that will continue until further notice of the ACC. The rate became effective with the first billing cycle in March 2023 and is designed to bring the PSA balancing account to near-zero over a 24-month period. On November 30, 2023, APS notified the ACC that it will be maintaining the current PSA rate of $0.019074 per kWh and an updated PSA adjustment schedule would not be filed at that time. 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. 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.

Environmental Improvement Surcharge. On March 5, 2024, the ACC approved the elimination of the EIS, and the surcharge is no longer in effect. The EIS 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. APS's February 1, 2023, EIS application requested an increase in the charge to $14.7 million, or $3.3 million over the prior-period charge. On March 10, 2023, APS filed an amended application requesting an EIS charge of $4.0 million, a decrease of $10.7 million from the February EIS request, and a decrease of $7.5 million from the prior-period charge. The revised 2023 EIS became effective with the first billing cycle in April 2023; however, with the elimination of the surcharge, it is no longer in effect, and any remaining amounts are being collected through base rates.

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, 2022, APS's annual wholesale transmission revenue requirement for all users of its transmission system decreased by approximately $33 million for the 12-month period beginning June 1, 2022, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates decreased by approximately $6.4 million and retail customer rates would have decreased by approximately $26.6 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 $2.4 million, resulting in a reduction to the residential rate and increases to commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2022.

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 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.

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 February 15, 2022, APS filed its 2022 annual LFCR adjustment, requesting that effective May 1, 2022, the annual LFCR recovery amount be increased to $59.1 million (a $32.5 million increase from previous levels, which was inclusive of a $11.8 million balance from APS's 2021 LFCR filing). On May 9, 2022, the ACC Staff filed its revised report and proposed order regarding APS's 2022 LFCR adjustment, concluding that APS calculated the adjustment in accordance with its Plan of Administration. On May 18, 2022, the ACC approved the 2022 LFCR adjustment, with a rate effective date of June 1, 2022.

On February 15, 2023, APS filed a letter to the ACC docket stating that, in accordance with Decision No. 78585, APS and ACC Staff have agreed to move the filing date for the annual LFCR adjustment to July 31 each year. On September 5, 2023, APS filed an updated LFCR Plan of Administration, which was approved by ACC Staff on December 8, 2023. 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). On October 19, 2023, a request for intervention was filed, which was granted. Consistent with an October 25, 2023, Procedural Order, the parties met and conferred and conducted limited discovery. 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.

Tax Expense Adjustor Mechanism. The TEAM helps address potential federal income tax reform and enable 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. As part of the 2019 Rate Case decision, there remains small true up balances in the TEAM balancing account. In the 2022 Rate Case, these true up balances are being recovered and amortized through 2032.

Court Resolution Surcharge. The CRS mechanism permits APS to recover certain costs associated with investments and expenses for APS's purchase and installation of 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, $26.2 million of which has been collected as of December 31, 2024, 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. See "2019 Retail Rate Case" above for more information.

Net Metering

The ACC's decision from APS's 2017 rate case (the "2017 Rate Case Decision") provides that payments by utilities for energy exported to the grid from residential DG solar facilities will be determined using a Resource Comparison Proxy ("RCP") methodology as determined in the ACC's generic Value and Cost of Distributed Generation docket. 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 April 29, 2022, APS filed an application to decrease the RCP price from 9.4 cents per kWh, which had been in effect since October 1, 2021, to 8.46 cents per kWh, reflecting a 10% annual reduction, to become effective September 1, 2022. On July 12, 2022, the ACC approved the RCP as filed.

On May 1, 2023, APS filed an application for revisions to the RCP. This application would decrease the RCP price to 7.619 cents 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 6.857 cents 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 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 Distributed Generation Docket. A procedural conference was held on November 1, 2023, to discuss the process going forward. As a result of the procedural conference, ACC Staff issued a request for information to investigate the issues related to this matter. A status conference was held on March 20, 2024 to determine if ACC Staff is prepared to present a recommendation on this matter at that time. Stakeholders provided responses to the ACC Staff's request for information on March 21, 2024. Another status conference took place on May 20, 2024 and ACC Staff issued a request for additional information to investigate the issues related to the matter on May 31, 2024. Stakeholders provided responses to the ACC Staff's request for additional information on July 1, 2024, and on October 15, 2024, the ACC Staff filed a report finding that the RCP is working as intended and recommending no changes to the RCP at this time. The ACC Staff also recommended that the ACC close the docket without a hearing or further action. The ACC has not yet acted on the ACC Staff's recommendation, and APS cannot predict the outcome of this matter.

Energy Modernization Plan

On May 26, 2023, the ACC opened a new docket to review articles within the Arizona Administrative Code related to Resource Planning, the Renewable Energy Standard and Tariff, and Electric Energy Efficiency Standards. On January 9, 2024, the ACC approved a rulemaking process for this matter. During the ACC Open Meeting on February 6, 2024, the ACC approved motions to direct ACC Staff to include recommendations to repeal the current Electric Energy Efficiency and Renewable Energy Standard 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 Electric Energy Efficiency and Renewable Energy Standard 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. APS cannot predict the outcome of this matter.

Integrated Resource Planning

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 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. See "Energy Modernization Plan" above for information regarding proposed changes to the IRP filings.

Equity Infusions

On October 27, 2023, APS filed a notice of intent to increase Pinnacle West's equity in APS in 2024. APS sought approval to receive from Pinnacle West in 2024 up to $500 million in additional equity infusions above the previously authorized limit of $150 million annually. The ACC approved the increased equity infusion limit for 2024 on January 9, 2024.

On April 19, 2024, APS submitted a request to the ACC to permanently modify Pinnacle West's permitted yearly equity infusions to equal up to 2.5% of APS's consolidated assets each calendar year on a three-year rolling average basis. On December 17, 2024, the ACC issued a financing order that approved an annual equity infusion allowance of 2.5% of APS's consolidated assets on a three-year rolling average basis.

Public Utility Regulatory Policies Act

Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), qualifying facilities are provided the right to sell energy and/or capacity to utilities and are granted relief from certain regulatory burdens. On December 17, 2019, the ACC mandated a minimum contract length of 18 years for qualifying facilities over 100 kW in Arizona and established that the rate paid to qualifying facilities must be based on the long-term avoided cost. "Avoided cost" is generally defined as the price at which the utility could purchase or produce the same amount of power from sources other than the qualifying facility on a long-term basis.

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"). 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. In addition, APS voluntarily began waiving late payment fees of its customers ("Late Fee Waivers") on March 13, 2020. Effective February 1, 2023, late payment fees for residential customers were reinstated. Late payment fees for commercial and industrial customers were reinstated effective May 1, 2022. Since the suspensions and moratoriums on disconnections began, APS has experienced an increase in bad debt expense and the related write-offs of delinquent customer accounts.

Retail Electric Competition Rules

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC's retail electric competition rules. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACC's retail electric competition rules. During a July 15, 2020, ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. In April 2022, the Arizona Legislature passed, and the Governor signed a bill that repealed the electric deregulation law that

had been in place in Arizona since 1998. On August 27, 2024, the ACC administratively closed this docket due to inactivity and obsolescence.

Four Corners SCR Cost Recovery

On December 29, 2017, in accordance with the 2017 Rate Case Decision, APS filed a Notice of Intent to file its SCR Adjustment to permit recovery of costs associated with the installation of SCR equipment at Four Corners Units 4 and 5. APS filed the SCR Adjustment request in April 2018. The SCR Adjustment request provided that there would be a $67.5 million annual revenue impact that would be applied as a percentage of base rates for all applicable customers. Also, as provided for in the 2017 Rate Case Decision, APS requested that the adjustment become effective no later than January 1, 2019. The hearing for this matter occurred in September 2018. At the hearing, APS accepted ACC Staff's recommendation of a lower annual revenue impact of approximately $58.5 million. The Administrative Law Judge issued a ROO finding that the costs for the SCR project were prudently incurred and recommending authorization of the $58.5 million annual revenue requirement related to the installation and operation of the SCRs. The ACC did not issue a decision on this matter. APS included the costs for the SCR project in the retail rate base in its 2019 Rate Case filing with the ACC.

On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance. The Arizona Court of Appeals heard oral arguments on November 30, 2022. On March 6, 2023, the Court of Appeals issued its order in the matter, vacating the ACC's disallowance of the SCR investment and remanding the matter back to the ACC for further review in accordance with ACC rules and the order of the Court of Appeals. On June 21, 2023, the ACC approved a joint settlement filed by APS and the ACC's Legal Division that resolved all issues relating to the 2019 Rate Case decision, including recovery of the cost of the Four Corners SCRs. See above for further discussion on the 2019 Rate Case decision.

Cholla

On September 11, 2014, APS announced that it would close Unit 2 of the Cholla Power Plant ("Cholla") and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if the 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 is required to cease burning coal at its remaining Cholla units by April 2025.

Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS has been recovering a return on and of the net book value of the unit in base rates. APS is allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs, $28.1 million as

of December 31, 2024, in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. In accordance with the 2019 Rate Case decision, the regulatory asset is being amortized through 2033.

On August 14, 2024, APS filed a request with the ACC for a deferral order associated with unrecovered book value and closure costs of the remaining Cholla units. This order would authorize APS to defer, for future recovery in rates, both the expenses necessary to close and decommission 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. APS cannot predict the outcome of this matter.

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 a regulatory asset.

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, $33.4 million as of December 31, 2024, 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, $7.9 million as of December 31, 2024. 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. APS cannot predict the outcome of this matter.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Regulatory Assets and Liabilities

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

	Amortization Through	December 31, 2024	December 31, 2023
Pension	(a)	$ 750,976	$ 696,476
Deferred fuel and purchased power (b) (c)	2025	287,597	463,195
Income taxes — AFUDC equity	2054	192,936	189,058
Ocotillo deferral	2034	114,775	128,636
SCR deferral (e)	2038	83,123	89,477
Lease incentives	(g)	70,541	46,615
Retired power plant costs	2033	68,380	83,536
Deferred fuel and purchased power — mark-to-market (Note 15)	2027	42,275	120,214
FERC Transmission true up	2026	35,159	616
Income taxes — investment tax credit basis adjustment	2056	34,834	34,230
Deferred compensation	2036	33,108	33,972
Deferred property taxes	2027	23,918	32,488
Palo Verde VIEs (Note 17)	2046	20,611	20,772
Power supply adjustor - interest	2025	11,525	19,416
Active Union Medical Trust	(f)	9,673	12,747
Mead-Phoenix transmission line contributions in aid of construction ("CIAC")	2050	8,384	8,716
Navajo coal reclamation	2026	7,905	10,883
Loss on reacquired debt	2038	6,682	7,965
Tax expense adjustor mechanism (b)	2031	4,534	5,190
Four Corners cost deferral	2024	—	7,922
Other	Various	3,522	3,912
Total regulatory assets (d)		$ 1,810,458	$ 2,016,036
Less: current regulatory assets		$ 420,969	$ 625,757
Total non-current regulatory assets		$ 1,389,489	$ 1,390,279

(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 OCI and result in lower future revenues. As a result of the 2019 Rate Case decision, the amount authorized for inclusion in rate base was determined using an averaging methodology, which resulted in a reduced return in retail rates. The 2022 Rate Case decision allows for the full return on the pension asset in rate base. See Note 7 for further discussion.
(b) See "Cost Recovery Mechanisms" discussion above.
(c) Subject to a carrying charge.
(d) 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, Transmission Cost Adjustor and Other Transmission Matters."
(e) See "Four Corners SCR Cost Recovery" discussion above.
(f) Collected in retail rates.
(g) Amortization periods vary based on specific terms of lease contract.

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

	Amortization Through	December 31, 2024	December 31, 2023
Excess deferred income taxes - ACC — Tax Cuts and Jobs Act (a)	2046	$ 888,896	$ 930,344
Excess deferred income taxes - FERC — Tax Cuts and Jobs Act (a)	2058	207,400	214,667
Asset retirement obligations and removal costs	(d)	358,403	486,751
Other postretirement benefits	(c)	238,113	226,726
Four Corners coal reclamation	2038	77,532	68,521
Renewable energy standard (b)	2025	68,523	60,667
Income taxes — deferred investment tax credit	2056	66,327	55,917
Income taxes — change in rates	2053	59,133	43,251
Spent nuclear fuel	2027	26,818	33,154
Demand side management (b)	2025	23,927	14,374
Sundance maintenance	2031	23,086	19,989
TCA Balancing Account (b)	2026	14,834	3,425
Property tax deferral	2027	4,785	10,850
Tax expense adjustor mechanism (b)	2032	4,343	4,835
Other	Various	113	2,317
Total regulatory liabilities		$ 2,062,233	$ 2,175,788
Less: current regulatory liabilities		$ 206,955	$ 209,923
Total non-current regulatory liabilities		$ 1,855,278	$ 1,965,865

(a) For purposes of presentation on the Statement 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) See “Cost Recovery Mechanisms” discussion above.
(c) See Note 7.
(d) In accordance with regulatory accounting, APS accrues removal costs for its regulated assets, even if there is no legal obligation for removal.

4. 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, investment tax credit (“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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. See Note 20 for more information about the BCE Sale.

As a part of the Inflation Reduction Act of 2022 ("IRA"), a new PTC for nuclear energy produced by existing nuclear energy plants ("Nuclear PTC") was enacted. Energy produced and sold by APS from Palo Verde between 2024 and 2032 is eligible for this credit subject to a credit phase out based upon APS's gross receipts from nuclear sales. The Company continues to await guidance from the U.S. Treasury Department related to the definition of "gross receipts from nuclear sales" for purposes of the credit phase-out. Without such guidance, the Company is unable to accurately determine the benefit the Nuclear PTC may provide. Due to the lack of guidance, no income tax benefits have been recognized related to the Nuclear PTC as of December 31, 2024.

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 17 for additional details related to Palo Verde sale leaseback VIEs.

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		
	2024	2023	2022	2024	2023	2022
Total unrecognized tax benefits, January 1	$ 44,274	$ 43,097	$ 45,086	$ 44,274	$ 43,097	$ 45,086
Additions for tax positions of the current year	1,271	1,473	1,399	1,271	1,473	1,399
Additions for tax positions of prior years	2,031	419	2,069	2,031	419	2,069
Reductions for tax positions of prior years for:						
Changes in judgment	(2,043)	661	(3,495)	(2,043)	661	(3,495)
Settlements with taxing authorities	—	—	—	—	—	—
Lapses of applicable statute of limitations	(1,184)	(1,376)	(1,962)	(1,184)	(1,376)	(1,962)
Total unrecognized tax benefits, December 31	$ 44,349	$ 44,274	$ 43,097	$ 44,349	$ 44,274	$ 43,097

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		
	2024	2023	2022	2024	2023	2022
Tax positions, that if recognized, would decrease our effective tax rate	$ 27,899	$ 28,762	$ 28,246	$ 27,899	$ 28,762	$ 28,246

As of the balance sheet date, the tax year ended December 31, 2021, 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 2020.

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		
	2024	2023	2022	2024	2023	2022
Unrecognized tax benefit interest expense/ (benefit) recognized	$ 2,743	$ 452	$ (139)	$ 2,743	$ 452	$ (139)

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		
	2024	2023	2022	2024	2023	2022
Unrecognized tax benefit interest accrued	$ 4,376	$ 1,633	$ 1,181	$ 4,376	$ 1,633	$ 1,181

Additionally, as of December 31, 2024, we have recognized approximately $2.1 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.

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,		
	2024	2023	2022	2024	2023	2022
Current:						
Federal	$ 137,342	$ 21,272	$ 35,617	$ 165,653	$ 26,405	$ 103,349
State	2,392	2,854	1,950	26,054	1,027	161
Total current	139,734	24,126	37,567	191,707	27,432	103,510
Deferred:						
Federal	(53,228)	37,273	23,693	(69,075)	44,922	(31,860)
State	24,023	15,513	13,567	4,361	21,830	19,150
Total deferred	(29,205)	52,786	37,260	(64,714)	66,752	(12,710)
Income tax expense/(benefit)	$ 110,529	$ 76,912	$ 74,827	$ 126,993	$ 94,184	$ 90,800

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following chart compares pretax income at the 21% statutory federal income tax rate to income tax expense (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	Year Ended December 31,			Year Ended December 31,		
	2024	2023	2022	2024	2023	2022
Federal income tax expense at statutory rate	$ 154,677	$ 125,095	$ 120,887	$ 165,090	$ 138,337	$ 132,920
Increases (reductions) in tax expense resulting from:						
State income tax net of federal income tax benefit	24,218	18,024	17,740	25,639	19,832	19,000
State income tax credits net of federal income tax benefit	(3,349)	(3,513)	(5,482)	(1,611)	(1,775)	(3,744)
Excess deferred income taxes — Tax Cuts and Jobs Act	(36,559)	(36,558)	(36,241)	(36,559)	(36,558)	(36,241)
Allowance for equity funds used during construction (Note 1)	(2,545)	(5,964)	(4,629)	(2,545)	(5,964)	(4,629)
Palo Verde VIE noncontrolling interest (Note 17)	(3,617)	(3,617)	(3,617)	(3,617)	(3,617)	(3,617)
Investment tax credit amortization	(9,425)	(9,495)	(5,608)	(9,425)	(9,495)	(5,608)
Federal production tax credit	(15,206)	(8,441)	(3,146)	(12,110)	(5,460)	—
Other federal income tax credits	(3,881)	(3,453)	(7,721)	(1,551)	(2,803)	(7,721)
Other	6,216	4,834	2,644	3,682	1,687	440
Income tax expense/(benefit)	$ 110,529	$ 76,912	$ 74,827	$ 126,993	$ 94,184	$ 90,800

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,	
	2024	2023	2024	2023
DEFERRED TAX ASSETS				
Risk management activities	$ 14,539	$ 31,411	$ 14,539	$ 31,411
Regulatory liabilities:				
Excess deferred income taxes — Tax Cuts and Jobs Act	271,004	283,161	271,004	283,161
Asset retirement obligation and removal costs	81,308	113,312	81,308	113,312
Unamortized investment tax credits	66,327	68,521	66,327	68,521
Other postretirement benefits	58,862	56,070	58,862	56,070
Other	47,671	39,857	47,671	39,857
Operating lease liabilities	400,771	316,067	400,442	315,670
Pension liabilities	39,070	33,294	36,100	29,918
Coal reclamation liabilities	42,391	45,505	42,391	45,505
Renewable energy incentives	14,571	17,261	14,571	17,261
Credit and loss carryforwards	7,682	43,940	—	3,031
Employee benefit liabilities	57,853	49,222	56,561	48,551
Other	44,412	28,643	44,412	29,314
Total deferred tax assets	1,146,461	1,126,264	1,134,188	1,081,582
DEFERRED TAX LIABILITIES				
Plant-related	(2,562,990)	(2,572,495)	(2,562,990)	(2,572,495)
Risk management activities	(4,089)	(1,682)	(4,089)	(1,682)
Pension and other postretirement assets	(83,401)	(78,853)	(82,925)	(78,297)
Other special use funds	(55,146)	(56,550)	(55,146)	(56,550)
Operating lease right-of-use assets	(400,771)	(316,067)	(400,443)	(315,670)
Regulatory assets:				
Allowance for equity funds used during construction	(47,694)	(46,754)	(47,694)	(46,754)
Deferred fuel and purchased power	(84,393)	(149,078)	(84,393)	(149,078)
Pension benefits	(185,641)	(172,239)	(185,641)	(172,239)
Ocotillo deferral	(28,372)	(31,812)	(28,372)	(31,812)
SCR deferral	(20,548)	(22,128)	(20,548)	(22,128)
Retired power plant costs	(16,904)	(20,659)	(16,904)	(20,659)
Other	(57,602)	(38,320)	(57,602)	(38,320)
Other	(43,383)	(36,107)	(7,378)	(7,595)
Total deferred tax liabilities	(3,590,934)	(3,542,744)	(3,554,125)	(3,513,279)
Deferred income taxes — net	$ (2,444,473)	$ (2,416,480)	$ (2,419,937)	$ (2,431,697)

As of December 31, 2024, Pinnacle West consolidated deferred tax assets for credit and loss carryforwards relate to federal and state credit carryforwards, net of federal benefit, of $12 million, which first begin to expire in 2029. Pinnacle West consolidated credit and loss carryforwards amount above has been reduced by $4 million of unrecognized tax benefits.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As of December 31, 2024, APS consolidated does not have any deferred tax assets for credit and loss carryforwards relating to federal or state carryforwards due to APS utilizing all available federal and state credits in 2024.

5. 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, 2024			December 31, 2023		
	Pinnacle West	APS	Total	Pinnacle West	APS	Total
Commitments under Credit and Term Loan Facilities	$ 400,000	$1,650,000	$2,050,000	$ 200,000	$ 1,250,000	$ 1,450,000
Outstanding short-term borrowings	(228,550)	(339,900)	(568,450)	(76,650)	(532,850)	(609,500)
Amount of Credit and Term Loan Facilities Available	$ 171,450	$1,310,100	$1,481,550	$ 123,350	$ 717,150	$ 840,500
Weighted-Average Commitment Fees	0.225%	0.175%		0.170%	0.120%	

Pinnacle West

On August 2, 2024, Pinnacle West amended its $200 million revolving credit facility, extending the maturity date from April 10, 2028 to April 10, 2029, and providing a mechanism to either update the Sustainability Table (as defined in the Pinnacle West revolving credit facility), which provides for a sustainability-linked pricing feature, or, in certain circumstances, terminate the sustainability-linked pricing feature for the final year. 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 permits an interest rate reduction or increase by meeting or missing targets related to specific environmental and employee health and safety sustainability objectives. 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. At December 31, 2024, Pinnacle West had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under its credit facility, and $29 million of outstanding commercial paper borrowings. The weighted-average interest rate for the outstanding borrowings on December 31, 2024, was 4.58%.

On December 5, 2024, Pinnacle West entered into an agreement with a new 364-day $200 million term loan facility that matures on December 4, 2025. Borrowings under the facility bear interest at SOFR plus 0.95% per annum. On December 20, 2024, Pinnacle West drew the full amount of $200 million. On December 20, 2024, Pinnacle West repaid $200 million of the Pinnacle West term loan which matured in December 2024.

APS

On August 2, 2024, APS amended its $1.25 billion revolving credit facility, extending the maturity date from April 10, 2028 to April 10, 2029, and providing a mechanism to either update the Sustainability Table (as defined in the APS revolving credit facility), which provides for a sustainability-linked pricing feature, or, in certain circumstances, terminate the sustainability-linked pricing feature for the final year. APS has the option to increase the amount of the facility by up to a maximum of $400 million, for 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 permits an interest rate reduction or increase by meeting or missing targets related to specific environmental and employee health and safety sustainability objectives. The facility is available to support APS's general corporate purposes, including support for APS's commercial paper program, which was increased from $750 million to $1 billion on April 10, 2023, for bank borrowings or for issuances of letters of credit. At December 31, 2024, APS had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under the credit facility, and $340 million of outstanding commercial paper borrowings. The weighted-average interest rate for the outstanding borrowings on December 31, 2024, was 4.62%.

On December 12, 2023, APS entered into an agreement for a new 364-day $350 million term loan facility that matured on December 10, 2024. Borrowings under the facility boar interest at SOFR plus 1.0% per annum. On February 9, 2024, APS drew the full amount of $350 million, which APS subsequently paid off in full on June 10, 2024.

On December 5, 2024, APS entered into a $400 million 364-Day Term Loan Agreement that matures on December 4, 2025. Borrowings under the facility bear interest at SOFR plus 0.90% per annum. As of the date of this report, APS has not drawn on this term loan.

See "Financial Assurances" in Note 10 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 6 for additional long-term debt provisions.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

6. 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, 2024	December 31, 2023
APS				
Pollution control bonds:				
Variable	2029	(b)	$ 163,975	$ 163,975
Total pollution control bonds			163,975	163,975
Senior unsecured notes	2025-2050	2.20%-6.88%	7,380,000	7,180,000
Unamortized discount			(14,252)	(14,197)
Unamortized premium			9,955	11,162
Unamortized debt issuance cost			(48,800)	(49,049)
Total APS long-term debt			7,490,878	7,291,891
Less current maturities			300,000	250,000
Total APS long-term debt less current maturities			7,190,878	7,041,891
Pinnacle West				
Senior unsecured notes	2025-2027	1.30%-4.75%	1,025,000	500,000
Floating rate note	2026	(c)	350,000	—
Term loans	2024	(d)	—	625,000
Unamortized discount			(5)	(15)
Unamortized debt issuance cost			(7,225)	(1,254)
Total Pinnacle West long-term debt			1,367,770	1,123,731
Less current maturities			500,000	625,000
Total Pinnacle West long-term debt less current maturities			867,770	498,731
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$ 8,058,648	$ 7,540,622

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturities.

(b) The weighted-average interest rate for the variable rate pollution control bonds was 4.01% at December 31, 2024, and 4.11% at December 31, 2023.

(c) The weighted-average interest rate was 5.88% at December 31, 2024, and was not applicable at December 31, 2023. See additional details below.

(d) The weighted-average interest rate was not applicable at December 31, 2024, and was 6.20% at December 31, 2023. See additional details below.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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
2025	$ 800,000	$ 300,000
2026	600,000	250,000
2027	825,000	300,000
2028	—	—
2029	568,975	568,975
Thereafter	6,125,000	6,125,000
Total	$ 8,918,975	$ 7,543,975

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, 2024		As of December 31, 2023	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 1,367,770	$ 1,393,744	$ 1,123,731	$ 1,095,935
APS	7,490,878	6,525,248	7,291,891	6,459,718
Total	$ 8,858,648	$ 7,918,992	$ 8,415,622	$ 7,555,653

Credit Facilities and Debt and Equity Issuances

Pinnacle West

On December 16, 2022, Pinnacle West entered into a $175 million term loan facility that matured on December 16, 2024. The proceeds were received on January 6, 2023, and used for general corporate purposes. We recognized the term loan facility as long-term debt upon settlement on January 6, 2023. On June 10, 2024 Pinnacle West repaid the full $175 million term loan, that matured on December 16, 2024.

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. In December 2024, Pinnacle West partially settled the 2024 Forward Sale Agreements by issuing 5,377,115 shares of common stock and receiving net proceeds of $345 million. The proceeds were recorded in equity. At December 31, 2024, Pinnacle West could have settled the remaining February 2024 Forward Sale Agreements with the issuance of 5,863,486 shares of common stock, which would have provided cash liquidity to Pinnacle West of approximately $377 million. See Note 13.

On November 8, 2024, Pinnacle West entered into an equity forward sale agreement under the ATM program (the "November 2024 ATM Forward Sale Agreement"), which may be settled with Pinnacle West common stock or cash. At December 31, 2024, Pinnacle West could have settled the November 2024 ATM Forward Sale Agreement with the issuance of 552,833 shares of common stock, which would have provided cash liquidity to Pinnacle West of approximately $50 million. See Note 13.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Convertible Senior Notes. In June 2024, Pinnacle West issued $525 million of 4.75% convertible senior notes due 2027 (the "Convertible Notes"), which are senior unsecured obligations of Pinnacle West, and will mature on June 15, 2027. The Convertible Notes bear interest at a fixed rate of 4.75% per year, payable semiannually in arrears on June 15 and December 15 of each year, beginning on December 15, 2024. Proceeds from the Convertible Notes were used to repay APS's 364-day $350 million term loan facility that matured on December 10, 2024 and commercial paper borrowings.

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 of Pinnacle West's common stock. 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, 2024, 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, including unamortized debt issuance costs of $8 million. The estimated fair value of the Convertible Notes as of December 31, 2024 was $552 million (Level 2 within the fair value hierarchy).

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As of December 31, 2024, 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. See Note 13.

Floating Rate Notes. In June 2024, Pinnacle West completed the sale of $350 million Floating Rate Notes due 2026 (the "Floating Rate Notes"). The Floating Rate Notes are senior unsecured obligations of Pinnacle West and will mature on June 10, 2026. The Floating Rate Notes bear a variable interest rate of Compounded SOFR (as defined in the Fifth Supplemental Indenture dated as of June 10, 2024) plus 82 basis points per year. Proceeds were used to repay a portion of Pinnacle West's $450 million term loan that matured in December 2024 and the full amount of Pinnacle West's $175 million term loan that matured in December 2024.

On June 10, 2024, Pinnacle West repaid $250 million of its $450 million term loan which matured in December 2024. On December 20, 2024, Pinnacle West repaid the remaining $200 million of the term loan.

On June 10, 2024 Pinnacle West repaid the full $175 million term loan, that matured on December 16, 2024.

APS

APS was previously authorized to receive up to $150 million annually in equity infusions from Pinnacle West without seeking ACC approval. In 2023, APS sought approval for an additional $500 million in equity infusions and received approval in early 2024. Subsequently, APS requested and the ACC issued a new financing order that approved 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 June 12, 2024, Pinnacle West contributed $450 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness. On December 23, 2024, Pinnacle West contributed $345 million into APS in the form of an equity infusion. APS used this contribution to repay a portion of commercial paper borrowings and for other general corporate purposes.

On May 9, 2024, APS issued $450 million of 5.7% senior unsecured notes that mature August 15, 2034. The net proceeds from the sale were used to repay short-term indebtedness consisting of commercial paper and for general corporate purposes.

On June 17, 2024, APS repaid its $250 million 3.35% senior unsecured notes at maturity from commercial paper borrowings.

See "Lines of Credit and Short-Term Borrowings" in Note 5 and "Financial Assurances" in Note 10 for discussion of APS's separate outstanding letters of credit.

BCE

On February 11, 2022, a special purpose subsidiary of BCE entered into a credit agreement to finance capital expenditures and related costs for the development of a 31 megawatt ("MW") solar and 20 megawatt hour ("MWh") battery storage project in Los Alamitos, California ("Los Alamitos"). The credit

agreement consisted of an equity bridge loan facility, a non-recourse construction facility, a letter of credit facility, and a related interest rate swap. On August 4, 2023, Pinnacle West entered into a purchase and sale agreement with Ameresco, Inc. ("Ameresco"), pursuant to which we agreed to sell all our equity interest in BCE to Ameresco (the "BCE Sale"). See Note 20. As a part of the BCE Sale closing, the $36 million construction facility, the letter of credit facility, and the interest rate swap were transferred to Ameresco. On August 4, 2023, concurrent with the BCE Sale, Pinnacle West paid in full the outstanding $31 million equity bridge loan balance. As of December 31, 2024, there is no outstanding balance on our Consolidated Balance Sheets relating to this credit agreement.

On April 18, 2023, and on December 29, 2023, Pinnacle West issued performance guarantees in connection with BCE's Kūpono Solar investment project financing. BCE held an equity method investment relating to the Kūpono Solar project that was included in the BCE Sale relating to the stage of the BCE Sale that closed on January 12, 2024. The performance guarantees did not transfer in the BCE Sale, and Pinnacle West continues to retain these performance guarantees. See Note 10.

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 this covenant. 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, 2024, the ratio was approximately 59% for Pinnacle West and 49% 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 loan agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under certain other material agreements. All of APS's bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under certain other material agreements. Pinnacle West and APS do not have a material adverse change restriction 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.

On April 19, 2024, APS submitted an application to the ACC requesting to increase the long-term debt limit from $8.0 billion to $9.5 billion and to increase Pinnacle West's permitted yearly equity infusions to equal up to 2.5% of APS's consolidated assets each calendar year on a three-year rolling average basis. On December 17, 2024, the ACC issued a financing order approving the increase of the long-term debt limit to $9.5 billion and the permitted yearly equity infusions to 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 5 for additional short-term debt provisions.

7. 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 12 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 3.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides details 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		
	2024	2023	2022	2024	2023	2022
Service cost-benefits earned during the period	$ 43,641	$ 39,461	$ 55,473	$ 9,955	$ 8,567	$ 16,470
Non-service costs (credits):						
Interest cost on benefit obligation	148,643	153,561	107,492	22,169	22,509	17,491
Expected return on plan assets	(188,651)	(182,938)	(185,775)	(46,834)	(43,486)	(46,042)
Amortization of:						
Prior service credit (a)	—	—	—	(37,789)	(37,789)	(37,789)
Net actuarial loss (gain)	41,915	38,420	17,515	(8,676)	(9,614)	(12,835)
Net periodic benefit costs (credits)	$ 45,548	$ 48,504	$ (5,295)	$ (61,175)	$ (59,813)	$ (62,705)
Portion of costs (credits) charged to expense	$ 23,652	$ 27,029	$ (16,431)	$ (45,557)	$ (43,408)	$ (45,042)

(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 with the last full-year amortization occurring in 2024.

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

	Pension Plans		Other Benefits Plans	
	2024	2023	2024	2023
Change in Benefit Obligation				
Benefit obligation at January 1	$ 2,908,063	$ 2,809,529	$ 430,434	$ 409,461
Service cost	43,641	39,461	9,955	8,567
Interest cost	148,643	153,561	22,169	22,509
Benefit payments	(216,238)	(210,737)	(30,516)	(30,784)
Actuarial (gain) loss	(91,800)	116,249	(71,952)	20,681
Benefit obligation at December 31	2,792,309	2,908,063	360,090	430,434
Change in Plan Assets				
Fair value of plan assets at January 1	2,835,549	2,829,485	696,494	652,287
Actual return on plan assets	4,518	199,098	32,816	67,317
Benefit payments	(200,205)	(193,034)	(27,118)	(23,110)
Fair value of plan assets at December 31	2,639,862	2,835,549	702,192	696,494
Funded (Underfunded) Status at December 31	$ (152,447)	$ (72,514)	$ 342,102	$ 266,060

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

	As of December 31,	
	2024	2023
Accumulated benefit obligation	$ 113,541	$ 123,701
Fair value of plan assets	—	—

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The Pinnacle West Capital Corporation Retirement Plan is more than 100% funded on an accumulated benefit obligation basis at December 31, 2024, and December 31, 2023, therefore, the only pension plan with an accumulated benefit obligation in excess of plan assets in 2024 and 2023 is a 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,	
	2024	2023
Projected benefit obligation	$ 2,792,309	$ 129,891
Fair value of plan assets	2,639,862	—

The Pinnacle West Capital Corporation Retirement Plan, on a projected benefit obligation basis, was 99% funded at December 31, 2024 and 102% funded at December 31, 2023. For 2024, we included both the projected benefit obligation and the fair value of plan assets for our qualified pension plan and a non-qualified supplemental excess benefit retirement plan. In 2023, the only plan that was underfunded was the non-qualified supplemental excess benefit retirement plan.

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

	Pension Plans		Other Benefits Plans	
	2024	2023	2024	2023
Noncurrent asset	$ —	$ 57,378	$ 342,102	$ 266,060
Current liability	(13,130)	(17,190)	—	—
Noncurrent liability	(139,317)	(112,702)	—	—
Net amount recognized (funded status)	$ (152,447)	$ (72,514)	$ 342,102	$ 266,060

The following table shows the details related to accumulated other comprehensive loss (gain) as of December 31, 2024, and 2023 (dollars in thousands):

	Pension Plans		Other Benefits Plans	
	2024	2023	2024	2023
Net actuarial loss (gain)	$ 793,421	$ 743,003	$ (237,889)	$ (188,630)
Prior service credit	—	—	(1,265)	(39,054)
APS's portion recorded as a regulatory (asset) liability	(750,976)	(696,476)	238,113	226,726
Income tax expense (benefit)	(10,354)	(11,506)	611	691
Accumulated other comprehensive loss (gain)	$ 32,091	$ 35,021	$ (430)	$ (267)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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,		
	2024	2023	2024	2023	2022
Discount rate – pension plans	5.68 %	5.21 %	5.21 %	5.56 %	2.92 %
Discount rate – other benefits plans	5.71 %	5.23 %	5.23 %	5.58 %	2.98 %
Rate of compensation increase	4.50 %	4.52 %	4.52 %	4.57 %	4.00 %
Expected long-term return on plan assets - pension plans	N/A	N/A	6.90 %	6.70 %	5.00 %
Expected long-term return on plan assets - other benefit plans	N/A	N/A	6.85 %	6.80 %	5.35 %
Initial healthcare cost trend rate (pre-65 participants)	6.50 %	6.25 %	6.25 %	6.50 %	6.00 %
Ultimate healthcare cost trend rate (pre-65 participants)	4.50 %	4.75 %	4.75 %	4.75 %	4.75 %
Number of years to ultimate trend rate (pre-65 participants)	6	5	4	5	3
Initial healthcare cost trend rate (post-65 participants)	1.00 %	2.00 %	2.00 %	2.00 %	2.00 %
Ultimate healthcare cost trend rate (post-65 participants)	— %	2.00 %	2.00 %	2.00 %	2.00 %
Interest crediting rate – cash balance pension plans	4.66 %	4.54 %	4.54 %	4.50 %	4.50 %

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 2025, we are assuming a 7.05% long-term rate of return for pension assets and 7.15% (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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2024, are as follows:

	Target Allocation	Actual Allocation
Long-term fixed income assets	80 %	79 %
Return-seeking assets	20 %	21 %
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, 2024, 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, 2024:

	Actual Allocation
Long-term fixed income assets	61 %
Return-seeking assets	39 %
Total	100 %

See Note 12 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, 2024, approximately $38 million of these commitments have been funded.

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.

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 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, 2023, by asset category, are as follows (dollars in thousands):

	Level 1	Level 2	Other (a)	Total
Pension Plan:				
Fixed income securities:				
Corporate	$ —	$ 1,415,346	$ —	$ 1,415,346
U.S. Treasury	622,273	—	—	622,273
Other (b)	—	135,184	—	135,184
Common stock equities (c)	150,657	—	—	150,657
Mutual funds (d)	112,791	—	—	112,791
Common and collective trusts:				
Equities	—	—	192,945	192,945
Real estate	—	—	140,613	140,613
Other (e)	—	—	65,740	65,740
Total	$ 885,721	$ 1,550,530	$ 399,298	$ 2,835,549
Other Benefits:				
Fixed income securities:				
Corporate	$ —	$ 189,902	$ —	$ 189,902
U.S. Treasury	207,665	—	—	207,665
Other (b)	—	8,372	—	8,372
Common stock equities (c)	139,952	—	—	139,952
Mutual funds (d)	22,256	—	—	22,256
Common and collective trusts:				
Equities	—	—	81,724	81,724
Real estate	—	—	20,001	20,001
Other (e)	21,146	—	5,476	26,622
Total	$ 391,019	$ 198,274	$ 107,201	$ 696,494

(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 2024 and 2023, 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 2025, 2026 or 2027. With regard to contributions to our other postretirement benefit plan, we did not make a contribution in 2024 or 2023 and do not expect to make any contributions in 2025, 2026 or 2027. The Company was reimbursed $27 million in 2024, $23 million in 2023, and $26 million in 2022 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
2025	$ 241,762	$ 28,753
2026	223,562	28,747
2027	230,335	28,276
2028	233,617	27,880
2029	232,591	27,645
Years 2030-2034	1,147,273	137,301

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 2024, 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 2024, $12 million for 2023, and $12 million for 2022.

8. 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 purchased power and energy storage agreements that qualify as lease arrangements. Our leases have remaining terms that expire in 2025 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. These 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 of these sale leaseback transactions are excluded from our lease disclosures as lease accounting is eliminated upon consolidation. See Note 17 for a discussion of VIEs.

APS has purchased power lease agreements that allow APS 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 purchased power lease agreements 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 August 2024.

The following table provides information related to our lease costs (dollars in thousands):

	Year Ended December 31,		
	2024	2023	2022
Operating Lease Cost - Purchased Power & Energy Storage Lease Contracts	$ 147,313	$ 126,655	$ 104,001
Operating Lease Cost - Land, Property, and Other Equipment	20,120	19,235	18,061
Total Operating Lease Cost	167,433	145,890	122,062
Variable Lease Cost (a)	144,108	135,007	122,040
Short-term Lease Cost	20,653	21,530	9,928
Total Lease Cost	$ 332,194	$ 302,427	$ 254,030

(a) Primarily relates to purchased power lease contracts.

Lease costs are primarily included as a component of operating expenses on our Consolidated Statements of Income. Lease costs relating to purchased power and energy storage 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 3. 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 purchased power lease contracts. Payments under most renewable purchased power 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, 2024		
Year	Purchased Power & Energy Storage Lease Contracts	Land, Property & Equipment Leases	Total
2025	$ 158,363	$ 16,834	$ 175,197
2026	172,087	14,830	186,917
2027	198,007	12,249	210,256
2028	201,804	9,591	211,395
2029	205,741	7,465	213,206
Thereafter	1,140,971	61,855	1,202,826
Total lease commitments	2,076,973	122,824	2,199,797
Less imputed interest	536,948	41,605	578,553
Total lease liabilities	$ 1,540,025	$ 81,219	$ 1,621,244

We recognize lease assets and liabilities upon lease commencement. At December 31, 2024, 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 $16.7 billion over the terms of the agreements. These arrangements primarily relate to energy storage assets. We expect lease commencement dates ranging from March 2025 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 3.

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,		
	2024	2023	2022
Cash paid for amounts included in the measurement of lease liabilities — operating cash flows:	$ 143,950	$ 123,472	$ 118,463
Right-of-use operating lease assets obtained in exchange for operating lease liabilities:	393,702 (a)	602,301 (b)	16,990

	December 31, 2024	December 31, 2023
Weighted average remaining lease term	11 years	10 years
Weighted average discount rate (c)	4.90 %	4.53 %

(a) Primarily relates to the three new energy storage operating lease agreements that commenced in 2024.
(b) Primarily relates to the two purchased power operating lease agreements that were modified in January 2023.
(c) 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

9. 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, 2024 (dollars in thousands):

	Percent Owned		Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating facilities:					
Palo Verde Units 1 and 3	29.1 %		$2,010,346	$1,081,321	$ 20,694
Palo Verde Unit 2 (a)	16.8 %		709,414	397,235	9,076
Palo Verde Common	28.0 %	(b)	898,401	366,027	47,962
Palo Verde Sale Leaseback		(a)	351,050	268,494	—
Four Corners Generating Station	63.0 %		1,848,412	705,667	56,226
Cholla Common Facilities (c)	50.5 %		301,035	231,170	1,743
Transmission facilities:					
Arizona Nuclear Power Project 500kV System	33.3 %	(b)	134,713	60,174	7,174
Navajo Southern System	24.7 %	(b)	88,528	38,797	626
Palo Verde — Yuma 500kV System	25.5 %	(b)	24,260	8,120	142
Four Corners Switchyards	58.0 %	(b)	84,367	23,886	309
Phoenix — Mead System	17.1 %	(b)	39,788	21,173	330
Palo Verde — Rudd 500kV System	50.0 %		95,785	34,254	1,808
Morgan — Pinnacle Peak System	63.2 %	(b)	117,500	29,013	287
Round Valley System	50.0 %		548	213	—
Palo Verde — Morgan System	87.5 %	(b)	266,547	46,327	208
Hassayampa — North Gila System	80.0 %		154,330	27,739	—
Cholla 500kV Switchyard	85.7 %		8,454	2,859	35
Saguaro 500kV Switchyard	60.0 %		29,850	15,768	101
Kyrene — Knox System	50.0 %		578	349	—
Agua Fria Switchyard	10.0 %		—	—	82

(a) See Note 17.
(b) Weighted-average of interests.
(c) PacifiCorp owns Cholla Unit 4 (see Note 3 for additional information), and APS operated the unit for PacifiCorp. Cholla Unit 4 was retired on December 24, 2020. The common facilities at Cholla are jointly-owned.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

10. 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 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 has recovered costs for ten claims pursuant to the terms of the August 15, 2014 settlement agreement, for ten separate time periods during July 1, 2011, through October 31, 2023. The DOE has approved and paid approximately $156.7 million for these claims (APS's share is approximately $45.6 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 2017 Rate Case Decision, this regulatory liability is being refunded to customers. See Note 3. On October 31, 2024, APS filed its eleventh claim pursuant to the terms of the August 15, 2014, settlement agreement in the amount of approximately $18 million (APS's share is approximately $5.3 million). In February 2025, the DOE approved approximately $17.6 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 Nuclear Electric Insurance Limited ("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 $23.1 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 $64.1 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.

Captive Insurance Cell

Pinnacle West has established a captive insurance program to supplement third-party 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 third-party insurance policies. The Captive policies exclude nuclear liability at Palo Verde. See Note 10. 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. See Note 17 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 2025 and 2048 that include required purchase provisions. APS estimates the contract requirements to be approximately $1,540 million in 2025; $1,742 million in 2026; $1,973 million in 2027; $2,142 million in 2028; $2,115 million in 2029; and $27.2 billion thereafter. 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. See Note 8.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table summarizes our estimated coal take-or-pay commitments (dollars in thousands):

	Year Ended December 31,					
	2025	2026	2027	2028	2029	Thereafter (b)
Coal take-or-pay commitments (a)	$ 208,984	$ 214,090	$ 212,529	$ 217,820	$ 223,291	$ 463,752

(a) Total take-or-pay commitments are approximately $1.5 billion. The total net present value of these commitments using a 4.81% discount rate is approximately $1.3 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,		
	2024	2023	2022
Total purchases	$ 237,821	$ 255,219	$ 305,502

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 $27 million in 2025; $24 million in 2026; $21 million in 2027; $18 million in 2028; $16 million in 2029; and $36 million thereafter. These amounts do not include purchases of renewable energy credits that are bundled with energy.

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 $171 million at December 31, 2024, and $184 million at December 31, 2023. Under our current coal supply agreements, APS expects to make payments for the final mine reclamation as follows: $20 million in 2025; $21 million in 2026; $22 million in 2027; $23 million in 2028; and $2 million thereafter. 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

The Comprehensive Environmental Response Compensation and Liability Act (“Superfund” or “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. APS's estimated costs related to this investigation and study is approximately $3 million. APS anticipates incurring additional expenditures in the future, but because the final costs associated with remediation requirements set forth in the RI/FS are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

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 ("RID"). 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 per-and polyfluoroalkyl ("PFAS") compounds 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 ("SIBW") Superfund site. The SIBW 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 SIBW 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 greenhouse gases, 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("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 ("WIIN") 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. At this time, Arizona Department of Environmental Quality ("ADEQ") has taken steps to develop a CCR permitting program and plans to propose state regulations governing CCR permitting over the summer of 2024. It remains unclear when EPA would approve that permitting program pursuant to the WIIN 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.

- With respect to APS's Cholla facility, APS's application for alternative closure was submitted to EPA on November 30, 2020. While EPA has deemed APS's application administratively "complete," the Agency's approval remains pending. If granted, this application would allow the continued disposal of CCR within Cholla's existing unlined CCR surface impoundments until the required date for ceasing coal-fired boiler operations in April 2025. This application will be subject to public comment and, potentially, judicial review. We expect to have a proposed decision from EPA regarding Cholla in 2025.

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 CCR management units ("CCRMUs"), which contain at least 1,000 tons of CCR, broadly encompass any location at an operating coal-fired power plant where CCR 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. At this time, APS is still evaluating the impacts of this final regulation on its business, with initial CCRMU site surveys due to be completed by February 2026 and final site investigation reports to be finalized by February 2027. Based on the information available to APS at this time, APS cannot reasonably estimate the fair value of the entire CCRMU asset retirement obligation. 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.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. The Navajo Plant disposed of CCR only in a dry landfill storage area. 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 subject to alternative closure). 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. 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 the EPA on June 19, 2019 and replaced by the Affordable Clean Energy ("ACE") regulations, which were a far narrower set of rules. While the U.S. Court of Appeals for the D.C. Circuit subsequently vacated the ACE 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In the 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.

As such, for new natural gas-fired combustion turbine power plants, EPA is proposing that carbon emission performance standards apply based on the annual capacity factors. For the highest utilization combustion turbines, EPA is therefore proposing that such facilities be retrofitted for carbon capture and sequestration or utilization controls ("CCS") by 2032. For intermediate or low-load natural gas fired combustion turbines, those with 40% or less capacity factors, EPA's regulations would not require add-on pollution controls. Instead, natural gas-fired combustion turbines with capacity factors of up to 20% would be effectively unregulated, while such turbines with capacity factors over 20% and up to 40% would be subject to carbon dioxide emission rate limitations. EPA did not finalize standards for existing natural gas-fired combustion turbines but has indicated that it will propose a new set of standards, initiating a separate rulemaking, for these existing gas-fired power plants within the next year.

For coal-fired power plants, instead of imposing regulations based on capacity and utilization, EPA has finalized subcategories based on planned retirement dates. This means that 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. We cannot predict the outcome of the litigation challenging EPA's latest carbon emission standards for power plants. In addition, the Trump administration has stated that it intends to reverse or substantially revise these standards. 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.

If this regulation remains in effect, it will 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 carbon capture and sequestration and achieve 90% capture efficiency may not be feasible. Future resource plans and procurement efforts implicating the development of such new generation remains pending and, as such, at this time APS is not able to quantify the financial impact associated with EPA's GHG regulations for power plants.

Effluent Limitation Guidelines. EPA published effluent limitation guidelines ("ELG") on October 13, 2020, and, based off those guidelines, APS completed a National Pollutant Discharge Elimination System ("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. Nonetheless, 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.

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 National Ambient Air Quality Standards ("NAAQS"). Thermal power plant emission limitations are a key aspect of these regulations, which involve emission allowance trading for nitrogen oxide ("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. As such, while EPA may elect to resume work on and finalize this proposal in the future, it is unlikely to do so over a near-term horizon. APS cannot predict the outcome of any future EPA efforts to add Arizona to the federal Good Neighbor Plan (which depends on action disapproving the Arizona State Implementation Plan) or whether the Good Neighbor Plan itself will remain in effect pending the outcome of judicial review in the D.C. Circuit Court of Appeals. Should 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 April 25, 2024, EPA finalized revisions to the existing MATS regulations governing emissions of toxic air pollution from existing coal-fired power plants. The final regulations increase the stringency of filterable particulate matter limits used to demonstrate compliance with MATS and require the use of continuous emissions monitoring systems to ensure compliance (as opposed to periodic performance testing). These final regulations will take effect for existing coal-fired power plants, such as Four Corners, within three years of publication in the Federal Register. Based on APS's assessment of the revised MATS regulations, this final rule is unlikely to have a material impact on plant operations or require significant capital expenditures to ensure compliance.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

Four Corners National Pollutant Discharge Elimination System ("NPDES") 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 ("EAB") took up review of the Four Corners NPDES Permit. The EAB denied the environmental group petition on September 30, 2020. While on January 22, 2021, the environmental groups filed a petition for review of the EAB'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 requires investigation of thermal wastewater discharges from Four Corners, administratively closes the litigation filed in January 2021, and APS does not expect the outcome to have a material impact on its financial condition, results of operations, or cash flows.

BCE Kūpono Solar

BCE and Ameresco jointly owned a special purpose entity that sponsored the Kūpono Solar Project. This project is a 42 MW solar and battery storage facility in Oʻahu, Hawaii that supplies energy and capacity under a 20-year power purchase agreement with Hawaiian Electric Company, Inc. The Kūpono Solar Project achieved commercial operations in June 2024. On April 18, 2023, the Kūpono special purpose entity entered into a $140 million non-recourse construction financing agreement. On August 14, 2024, the construction financing converted into long-term financing in the form of a sale-leaseback. In connection with the project financing, Pinnacle West issued performance guarantees relating to the Kūpono Solar Project. Investments in the Kūpono Solar Project were included in the BCE Sale which closed on January 12, 2024, and as a result of the BCE Sale, Pinnacle West holds no equity or ownership interest in the Kūpono Solar Project. As of December 31, 2024, Pinnacle West continues to maintain performance guarantees relating to the Kūpono Solar Project sale-leaseback financing (see additional information below regarding these guarantees). See Note 20 for information relating to the BCE Sale.

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, 2024, standby letters of credit totaled approximately $18 million and surety bonds totaled approximately $23 million; both will expire through 2025. 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 Palo Verde sale leaseback transactions 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 at December 31, 2024. In connection with the sale of 4C Acquisition, LLC's 7% interest to Navajo Transitional Energy Corporation ("NTEC"), Pinnacle West is guaranteeing certain obligations that NTEC will have 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 production tax credit 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, 2024, there is approximately $29 million of remaining guarantees relating to these PTC Guarantees that are expected to terminate by 2031.

Pinnacle West has issued various performance guarantees in connection with the Kūpono Solar Project investment financing and is exposed to losses relating to these guarantees upon the occurrence of certain events that we consider to be remote. Subsequent to the BCE Sale, Pinnacle West continues to maintain these guarantees. See Note 20. 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. The details of the guarantees are as follows:

- Pinnacle West committed to certain performance guarantees tied to the Kūpono Solar Project achieving certain construction and operation milestones. These performance guarantees expired in August 2024. Pinnacle West has no on-going exposure under these construction-related guarantees.

- 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 has agreed to make efforts to refinance the project and eliminate these guarantees prior to 2030.

11. Asset Retirement Obligations

In 2024, 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 $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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

- 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.

APS has also recorded the initial investigation and assessment costs related to the newly signed EPA rule for Legacy Impoundments and CCRMUs. At this time, APS is still estimating the financial impacts of this final regulation on its business, with initial CCRMU site surveys due to be completed by February 2026 and final site investigation reports to be finalized by February 2027. Based on the information available to APS at this time, APS cannot reasonably estimate the fair value of the entire CCRMU asset retirement obligation. 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 2023, 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 $71 million, primarily due to changes in the planned pond closure methodology and increased corrective action cost estimates associated with the CCR Rule.
- Four Corners coal-fired power plant, which resulted in a decrease of approximately $7 million.
- Navajo coal-fired plant, a decommissioned coal-fired power plant, which resulted in an increase of approximately $8 million.
- Palo Verde received a new decommissioning study, which resulted in an increase to the ARO in the amount of $63 million, an increase in the plant in service of $59 million and a decrease in the regulatory liability of $4 million.

See additional details in Notes 3 and 10.

The following table shows the change in our asset retirement obligations (dollars in thousands):

	2024	2023
Asset retirement obligations at the beginning of year	$ 966,001	$ 797,762
Changes attributable to:		
Accretion expense	56,143	44,269
Settlements	(18,379)	(14,039)
Estimated cash flow revisions	142,821	135,323
Newly incurred obligation	—	2,686
Asset retirement obligations at the end of year	$ 1,146,586	$ 966,001

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 3 for detail of regulatory liabilities.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

12. 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 semi-monthly 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 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 15.
(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 17.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value at December 31, 2023, 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	$ 10	$ —	$ —	$ —		$ 10
Risk management activities — derivative instruments:						
Commodity contracts	—	1,881	6,616	(1,689)	(a)	6,808
Nuclear decommissioning trusts:						
Equity securities	11,064	—	—	(767)	(b)	10,297
U.S. commingled equity funds	—	—	—	409,616	(c)	409,616
U.S. Treasury debt	319,734	—	—	—		319,734
Corporate debt	—	188,317	—	—		188,317
Mortgage-backed securities	—	208,306	—	—		208,306
Municipal bonds	—	59,323	—	—		59,323
Other fixed income	—	5,653	—	—		5,653
Subtotal nuclear decommissioning trusts	330,798	461,599	—	408,849		1,201,246
Other special use funds:						
Equity securities	40,991	—	—	2,196	(b)	43,187
U.S. Treasury debt	319,594	—	—	—		319,594
Subtotal other special use funds	360,585	—	—	2,196		362,781
Total assets	$ 691,393	$ 463,480	$ 6,616	$ 409,356		$ 1,570,845
LIABILITIES						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (127,016)	$ (1,695)	$ 4,823	(a)	$ (123,888)

(a) Represents counterparty netting, margin, and collateral. See Note 15.
(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.

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. See Note 3.

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 at December 31, 2024, and December 31, 2023:

	December 31, 2024 Fair Value (thousands)		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.

	December 31, 2023 Fair Value (thousands)		Valuation	Significant		Weighted-Average
Commodity Contracts	Assets	Liabilities	Technique	Unobservable Input	Range	(b)
Electricity Forward Contracts (a)	$ 6,587	$ 658	Discounted cash flows	Electricity forward price (per MWh)	$ 37.79 - $259.04	$158.08
Natural Gas Forward Contracts (a)	29	1,037	Discounted cash flows	Natural gas forward price (per MMBtu)	$0.00 - $0.08	$0.03
Total	$ 6,616	$ 1,695				

(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	**2024**	**2023**
Balance at beginning of period	$ 4,921	$ (4,888)
Total net losses realized/unrealized:		
Deferred as a regulatory asset or liability	(60,965)	(70,214)
Settlements	44,156	69,706
Transfers into Level 3 from Level 2	(4,635)	(1,289)
Transfers from Level 3 into Level 2	1,484	11,606
Balance at end of period	$ (15,039)	$ 4,921
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 value 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.

13. Common Stock Equity and Earnings Per Share

ATM Program

On November 8, 2024, Pinnacle West entered into an equity distribution sales agreement, pursuant to which Pinnacle West may sell, from time to time, up to $900 million of its common stock through an ATM program, which includes the ability to enter into forward sale agreements. As of December 31, 2024, approximately $850 million of common stock is available to be issued under the ATM Program, which takes into account the forward sale agreement in effect as of December 31, 2024.

As of December 31, 2024, Pinnacle West had an outstanding forward sale agreement under the ATM program relating to approximately $50 million of common stock (the "November 2024 ATM Forward Sale Agreement"). The November 2024 ATM Forward Sale Agreement may be settled at Pinnacle West's discretion no later than June 30, 2026. On a given settlement date, Pinnacle West will issue shares of common at the then-applicable forward sales price. The terms of the November 2024 ATM Forward Sale Agreement also allow Pinnacle West, at its option, to settle the agreements with the counterparties by delivering cash, in lieu of shares.

The initial forward sales price for the November 2024 ATM Forward Sale Agreement was approximately $89.73, subject to certain adjustments. On December 31, 2024, Pinnacle West could have settled the outstanding November 2024 ATM Forward Sale Agreement with the physical delivery of 552,833 shares of Pinnacle West common stock in exchange for cash of approximately $50 million. As of December 31, 2024, Pinnacle West has not received any proceeds relating to the November 2024 Forward

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Sale Agreement. Pinnacle West will receive proceeds, if any, when settlement occurs, and will record the proceeds, if any, in equity.

Non-ATM February 2024 Forward Sale Agreements

On February 28, 2024, Pinnacle West executed equity forward sale agreements, relating to 11,240,601 shares of Pinnacle West common stock ("February 2024 Forward Sale Agreements"). The February 2024 Forward Sale Agreements may be settled at our discretion no later than September 4, 2025, and were not issued under the ATM program discussed above. On a settlement date, Pinnacle West will issue shares of Pinnacle West common stock and receive 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 initial forward sales price for the February 2024 Forward Sale Agreements was initially, approximately $64.51 per share and is subject to adjustment based on the terms of the agreements. In December 2024, Pinnacle West partially settled the February 2024 Forward Sale Agreements with the issuance of 5,377,115 shares of common stock and received net proceeds of $345 million. The proceeds were recorded in equity.

At December 31, 2024, Pinnacle West could have settled the remaining February 2024 Forward Sale Agreements with the issuance of 5,863,486 shares of common stock in exchange for cash of $377 million. We will not receive any additional proceeds, if any, from the February 2024 Forward Sale Agreements until settlement occurs.

Convertible Notes

In June 2024, Pinnacle West issued $525 million of 4.75% convertible senior notes that will mature on June 15, 2027. The Convertible Notes conversion options are indexed to Pinnacle West's common stock. See Note 5.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Earnings Per Share

The following table presents the calculation of Pinnacle West's basic and diluted EPS (in thousands, except per share amounts):

	2024	2023	2022
Net income attributable to common shareholders	$ 608,806	$ 501,557	$ 483,602
Weighted average common shares outstanding — basic	113,846	113,442	113,196
Net effect of dilutive securities:			
Contingently issuable performance shares and restricted stock units	480	362	220
Dilutive shares related to equity forward sale agreements (a)	1,906	—	—
Total contingently issuable shares	2,386	362	220
Weighted average common shares outstanding — diluted	116,232	113,804	113,416
Earnings per weighted-average common share outstanding			
Net income attributable to common shareholders — basic	$ 5.35	$ 4.42	$ 4.27
Net income attributable to common shareholders — diluted	$ 5.24	$ 4.41	$ 4.26

(a) For the years ended December 31, 2024, 2023 and 2022, diluted weighted average common shares excludes 1,038,463, 0 and 0 shares, respectively, relating to the Convertible Notes and the ATM equity forward. These potentially issuable shares were excluded from the calculation of diluted shares as their inclusion would have been antidilutive.

The November 2024 ATM Forward Sale Agreements and the February 2024 Forward Sale Agreements are classified as equity transactions, and are not recorded on the Pinnacle West Consolidated Balance Sheets. Delivery of shares to settle equity forward agreements result in dilution to basic earnings per share (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 less that 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.

14. 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, 2024, 2.9 million common shares were available for issuance under the 2021 Plan. During 2024, 2023 and 2022, 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Stock-Based Compensation Expense and Activity

Compensation cost included in net income for stock-based compensation plans was $24 million in 2024, $17 million in 2023, and $16 million in 2022. The compensation cost capitalized is immaterial for all years. Income tax benefits related to stock-based compensation arrangements were $6 million in 2024, $3 million in 2023, and $2 million in 2022.

As of December 31, 2024, there were approximately $38 million of unrecognized compensation costs related to nonvested stock-based compensation arrangements. We expect to recognize these costs over a weighted-average period of two years.

The total fair value of shares vested was $24 million in 2024, $24 million in 2023, and $25 million in 2022.

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

	Restricted Stock Units, Stock Grants, and Stock Units (a)			Performance Shares (b)		
	2024	2023	2022	2024	2023	2022
Units granted	261,808	192,295	174,791	225,516	202,562	208,736
Weighted-average grant date fair value	$ 71.10	$ 74.32	$ 69.66	$ 72.89	$ 79.61	$ 77.63

(a) The Units granted does not include awards that will be cash settled in 2024, 2023 or 2022. 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, 2023	374,367		$ 73.29	347,283	$ 77.29
Granted	261,808		71.10	225,516	72.89
Vested	(155,345)		74.54	(165,194)	76.55
Forfeited (c)	(20,039)		71.32	(17,054)	75.69
Nonvested at December 31, 2024	460,791	(a)	71.72	390,551	77.29
Vested Awards Outstanding at December 31, 2024	70,851			165,194	

(a) Includes 11,750 of 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 $8 million, $6 million, and $3 million in 2024, 2023 and 2022, respectively. This includes cash used to settle restricted stock units of $2

million, $3 million, and $3 million in 2024, 2023 and 2022, 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.

15. 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Our derivative instruments, excluding those qualifying for a scope exception, are recorded on the balance sheets as an asset or liability and are measured at fair value. See Note 12 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 13 for details relating to Pinnacle West's equity forward sale agreements and Note 5 for Pinnacle West's 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 3. 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, 2024	December 31, 2023
Power	GWh	1,051	1,212
Gas	Billion cubic feet	235	200

Gains and Losses from Energy Derivative Instruments

For the years ended December 31, 2024, 2023 and 2022, 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	2024	2023	2022
Net Gain (Loss) Recognized in Income	Fuel and purchased power (a)	(88,522)	(370,145)	307,287

(a) Amounts are before the effect of PSA deferrals.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

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.

As of December 31, 2024: (dollars in thousands)	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 counterparties, or received from 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As of December 31, 2023: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amounts Reported on Balance Sheets
Current assets	$ 8,497	$ (1,694)	$ 6,803	$ 5	$ 6,808
Investments and other assets	—	—	—	—	—
Total assets	8,497	(1,694)	6,803	5	6,808
Current liabilities	(85,736)	10,894	(74,842)	(6,071)	(80,913)
Deferred credits and other	(42,975)	—	(42,975)	—	(42,975)
Total liabilities	(128,711)	10,894	(117,817)	(6,071)	(123,888)
Total	$ (120,214)	$ 9,200	$ (111,014)	$ (6,066)	$ (117,080)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) Includes cash collateral provided to counterparties of $9,200 thousand 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 $6,071 thousand and cash margin provided to counterparties of $5 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, 2024, we have one counterparty for which our exposure represents approximately 26% of Pinnacle West's $16.6 million of risk management assets. This exposure relates to an ISDA master agreement with the respective counterparty. The counterparty is rated as investment grade by Standard & Poor'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 earnings 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 to 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, 2024
Aggregate fair value of derivative instruments in a net liability position	$ 62,603
Additional collateral in the event credit-risk related contingent features were fully triggered (a)	32,728

(a) This amount is after counterparty netting and includes those contracts which qualify for scope exceptions, which are excluded from the derivative details above.

We also have energy related non-derivative instrument contracts, including energy storage lease contracts, with investment grade credit-related contingent features, which could also require us to post additional collateral of approximately $416 million if our debt credit ratings were to fall below investment grade.

16. Other Income and Other Expense

The following table provides detail of Pinnacle West's Consolidated other income and other expense for 2024, 2023, and 2022 (dollars in thousands):

	2024	2023	2022
Other income:			
Interest income	$ 24,322 (a)	$ 27,242 (a)	$ 7,326
Gain on sale of BCE (Note 20)	22,988	6,205	—
Miscellaneous	1,304	219	590
Total other income	$ 48,614	$ 33,666	$ 7,916
Other expense:			
Non-operating costs	$ (27,370) (b)	$ (15,260)	$ (18,619)
Investment losses — net	(1,418)	(3,402)	(20,537) (c)
Miscellaneous	(5,348)	(6,394)	(13,229)
Total other expense	$ (34,136)	$ (25,056)	$ (52,385)

(a) The 2023 and 2024 Interest income is primarily related to PSA Interest. See Note 3.
(b) The 2024 Non-operating cost is primarily related to corporate giving.
(c) The 2022 investment loss is primarily related to an impairment of PNW Power's Clear Creek wind farm investment.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides detail of APS's other income and other expense for 2024, 2023, and 2022 (dollars in thousands):

	2024	2023	2022
Other income:			
Interest income (a)	$ 21,088 (a)	$ 26,853 (a)	$ 5,332
Miscellaneous	6	219	556
Total other income	$ 21,094	$ 27,072	$ 5,888
Other expense:			
Non-operating costs	$ (26,588) (b)	$ (14,070)	$ (15,579)
Miscellaneous	(3,110)	(4,194)	(10,529)
Total other expense	$ (29,698)	$ (18,264)	$ (26,108)

(a) The 2023 and 2024 Interest income is primarily related to PSA Interest. See Note 3.
(b) The 2024 Non-operating cost is primarily related to corporate giving.

17. 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 10 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 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 is 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 our Consolidated Balance Sheets, and the Captive's investment gains and losses reflected through earnings on our Consolidated Income Statements.

Consolidation of the Captive resulted in an increase in Pinnacle West net income of $5 million for 2024, and zero for 2023 and 2022. These amounts are fully attributable to Pinnacle West shareholders. Consolidation impacts Pinnacle West Consolidated Income Statement's operations and maintenance expense and other income line items.

Pinnacle West's Consolidated Balance Sheets as of December 31, 2024 include $34 million of assets relating to the Captive that is reported within the other special use funds line item. See Notes 12 and 18 for additional details on these investment holdings. Our Consolidated Balance Sheets as of December 31, 2023, include $5 million of assets relating to the Captive that is reported within the other assets line item.

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. APS will retain the assets through 2033 under all three lease agreements. APS will be required to make payments relating to the three leases in total of approximately $21 million annually for the period 2025 through 2033. At the end of the lease period, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors.

The leases' terms give APS the ability to utilize the assets for a significant portion of the assets' economic life, and therefore provide APS with the power to direct activities of the VIEs that most significantly impact the VIEs' economic performance. Predominantly due to the lease terms, APS has been deemed the primary beneficiary of these VIEs and therefore consolidates the VIEs.

As a result of consolidation, we eliminate lease accounting and instead recognize depreciation expense, resulting in an increase in net income of $17 million for each of 2024, 2023 and 2022. The increase in net income is entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Our Consolidated Balance Sheets include the following amounts relating to these VIEs (dollars in thousands):

	December 31, 2024	December 31, 2023
Palo Verde sale leaseback property, plant and equipment, net of accumulated depreciation	$ 82,556	$ 86,426
Equity — Noncontrolling interests	103,167	107,198

Assets of the VIEs 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 these VIEs 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 VIEs' noncontrolling equity participants and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written-down in value. If such an event were to occur during the lease periods, APS may be required to pay the noncontrolling equity participants approximately $345 million beginning in 2025, and up to $501 million over the lease extension terms.

For regulatory ratemaking purposes, the agreements continue to be treated as operating leases and, as a result, we have recorded a regulatory asset relating to the arrangements.

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 12 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 other 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 other regulatory liabilities. Activities relating to APS coal mine reclamation escrow account investments are included within the other special use funds in the table below.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 and 2023, APS was reimbursed $14 million for each year, 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 and liabilities. 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 in 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 summarizes the fair value of the nuclear decommissioning trusts and other special use fund assets (dollars in thousands):

	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 million of Other Special Use Fund investments in equity securities relating to the Captive.

	December 31, 2023					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 420,680	$ 40,991	$ 461,671		$ 336,555	$ —
Available for sale-fixed income securities	781,333	319,594	1,100,927	(a)	21,518	(40,868)
Other	(767)	2,196	1,429	(b)	39	—
Total	$ 1,201,246	$ 362,781	$ 1,564,027	(c)	$ 358,112	$ (40,868)

(a) As of December 31, 2023, the amortized cost basis of these available-for-sale investments is $1,120 million.
(b) Represents net pending securities sales and purchases.
(c) All amounts pertain to APS.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Year Ended December 31,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
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
2022			
Realized gains	$ 9,017	$ 420	$ 9,437
Realized losses	$ (40,239)	$ —	$ (40,239)
Proceeds from the sale of securities (a)	$ 979,639	$ 227,558	$ 1,207,197

(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.

Fixed Income Securities Contractual Maturities

The fair value of APS's fixed income securities, summarized by contractual maturities, at December 31, 2024, is as follows (dollars in thousands):

	Nuclear Decommissioning Trusts	Coal Reclamation Escrow Account	Active Union Employee Medical Account	Total
Less than one year	$ 19,868	$ 87,424	$ 39,090	$ 146,382
1 year – 5 years	268,974	58,598	154,768	482,340
5 years – 10 years	198,464	—	15,664	214,128
Greater than 10 years	356,734	—	—	356,734
Total	$ 844,040	$ 146,022	$ 209,522	$ 1,199,584

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2022	$ (32,332)		$ 897	$ (31,435)
Other comprehensive income/(loss) before reclassifications	(4,420)		713	(3,707)
Amounts reclassified from accumulated other comprehensive loss	1,998	(a)	—	1,998
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)

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 7.

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, 2022	$ (15,596)	
Other comprehensive (loss) before reclassifications	(3,383)	
Amounts reclassified from accumulated other comprehensive loss	1,760	(a)
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)	

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 7.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

20. Sale of Bright Canyon Energy

On August 4, 2023, Pinnacle West entered into a purchase and sale agreement pursuant to which we agreed to sell all of our equity interest in our wholly-owned subsidiary, BCE, to Ameresco. The transaction is 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 includes $41 million of liabilities that have been assumed by Ameresco. The consideration received by Pinnacle West includes 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. These assets were previously classified as assets held for sale on our December 31, 2023, Consolidated Balance Sheets. Our Consolidated Statements of Income for the year ended December 31, 2024, include a $23 million gain relating to the final stage of the BCE Sale.

As of January 12, 2024, all stages of the BCE Sale have been completed. As partial consideration for the BCE Sale, Pinnacle West received a $46 million interest-bearing promissory note from Ameresco. The note required Ameresco to make cash payments to Pinnacle West throughout 2024 and Pinnacle West received payment in full of the note receivable during the fourth quarter of 2024. As the note receivable has been paid in full, our December 31, 2024 Consolidated Balance Sheets do not include any amounts relating to the promissory note.

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. See Note 4.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 10.

21. New Accounting Standards

ASU 2023-07, Segment Reporting: Improvements to Reportable Segment Disclosures

In November 2023, a new standard was issued that modifies segment reporting disclosure requirements. The disclosure changes include information about a reportable segment's significant expenses, details relating to the entity's chief operating decision maker, and other disclosures. We adopted this standard on December 31, 2024, using a retrospective approach. The adoption of the new standard results in changes to our reportable segment disclosures, but does not impact how we identify reportable segments or our financial statement results. See Note 1.

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 will adopt this standard on December 31, 2025, using a prospective approach. The adoption of the new standard will result in changes to our income tax disclosures, but will not impact our accounting for income taxes or our financial statement results.

ASU 2024-03, Income Statement: 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 income statement. The standard is effective for us 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.

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,		
	2024	2023	2022
Operating expenses	$ 9,931	$ 11,249	$ 8,850
Other			
Equity in earnings of subsidiaries	643,703	539,962	500,042
Other income (expense)	23,835	2,823	(4,725)
Total	667,538	542,785	495,317
Interest expense	65,261	47,251	18,861
Income before income taxes	592,346	484,285	467,606
Income tax benefit	(16,460)	(17,272)	(15,996)
Net income attributable to common shareholders	608,806	501,557	483,602
Other comprehensive income (loss) — attributable to common shareholders	2,202	(1,709)	23,426
Total comprehensive income — attributable to common shareholders	$ 611,008	$ 499,848	$ 507,028

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,	
	2024	2023
ASSETS		
Current assets		
Cash and cash equivalents	$ 23	$ 9
Accounts receivable	163,203	163,829
Income tax receivable	6,673	1,832
Assets held for sale- investment in subsidiaries	—	35,139
Other current assets	434	28,379
Total current assets	170,333	229,188
Investments and other assets		
Investments in subsidiaries	8,435,150	7,369,159
Deferred income taxes	—	15,746
Other assets	21,966	22,839
Total investments and other assets	8,457,116	7,407,744
TOTAL ASSETS	$ 8,627,449	$ 7,636,932
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 3,471	$ 8,176
Accrued taxes	4,799	4,543
Common dividends payable	106,592	99,813
Short-term borrowings	228,550	76,650
Current maturities of long-term debt	500,000	625,000
Operating lease liabilities	138	127
Other current liabilities	11,389	11,400
Total current liabilities	854,939	825,709
Long-term debt less current maturities	867,770	498,731
Deferred income taxes	24,536	—
Pension liabilities	4,462	6,487
Operating lease liabilities	1,194	1,332
Other	17,070	19,811
Total deferred credits and other	47,262	27,630
COMMITMENTS AND CONTINGENCIES		
Common stock equity		
Common stock	3,118,294	2,744,491
Accumulated other comprehensive loss	(30,942)	(33,144)
Retained earnings	3,666,959	3,466,317
Total Pinnacle West Shareholders' equity	6,754,311	6,177,664
Noncontrolling interests	103,167	107,198
Total Equity	6,857,478	6,284,862
TOTAL LIABILITIES AND EQUITY	$ 8,627,449	$ 7,636,932

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,		
	2024	2023	2022
Cash flows from operating activities			
Net income	$ 608,806	$ 501,557	$ 483,602
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of subsidiaries — net	(643,703)	(539,962)	(500,042)
Gain on sale relating to BCE	(22,988)	(6,423)	—
Depreciation and amortization	75	76	76
Deferred income taxes	40,231	(13,955)	17,256
Accounts receivable	15,268	(28,273)	(8,535)
Accounts payable	(4,869)	1,839	3,431
Accrued taxes and income tax receivables — net	(4,584)	9,505	(25,157)
Dividends received from subsidiaries	401,400	393,600	385,800
Other	22,959	(14,201)	47,719
Net cash flow provided by operating activities	412,595	303,763	404,150
Cash flows from investing activities			
Proceeds from sale relating to BCE	84,322	23,400	—
Investments in subsidiaries	(827,752)	(119,682)	(186,630)
Repayments of loans from subsidiaries and other	1,132	6,526	14,308
Advances of loans to subsidiaries	(11,336)	(59,349)	(3,308)
Net cash flow used for investing activities	(753,634)	(149,105)	(175,630)
Cash flows from financing activities			
Issuance of long-term debt	867,387	175,000	300,000
Short-term debt borrowings under revolving credit facility	200,000	—	—
Short-term borrowings and (repayments) — net	(48,100)	60,930	2,420
Dividends paid on common stock	(394,663)	(386,486)	(378,881)
Repayment of long-term debt	(625,000)	—	(150,000)
Common stock equity issuance and purchases — net	341,429	(4,093)	(2,653)
Net cash flow used for financing activities	341,053	(154,649)	(229,114)
Net increase (decrease) in cash and cash equivalents	14	9	(594)
Cash and cash equivalents at beginning of year	9	—	594
Cash and cash equivalents at end of year	$ 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.

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, 2024. 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, 2024. 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, 2024, 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 fiscal quarter ended December 31, 2024, 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 OF PINNACLE WEST

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 21, 2025 (the "2025 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 2025 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 2025 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth information as of December 31, 2024, 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	1,632,699	—	2,941,625
Equity compensation plans not approved by security holders	—	—	—
Total	1,632,699	—	2,941,625

(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, and 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 14 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 2025 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 2025 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	2024	2023
Audit Fees (1)	$ 2,967,862	$ 2,707,633
Audit-Related Fees (2)	384,372	372,040
Tax Fees	—	—
All Other Fees (3)	—	1,672,676

(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 2023 and 2024.

(3) The aggregate fees billed for independent third-party advisory (quality assurance) services related to a large-scale information technology project.

Pinnacle West's Audit Committee pre-approves each audit service and non-audit service to be provided by APS's registered public accounting firm. 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 2024 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: a	Date Filed
3.1	Pinnacle West	Articles of Incorporation, restated as of May 21, 2008	3.1 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-8962	8/7/2008
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, File Nos. 1-8962 and 1-4473	2/25/2020
3.3	APS	Articles of Incorporation, restated as of May 25, 1988	4.2 to APS's Form 18 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report, File No. 1-4473	9/29/1993
3.3(1)	APS	Amendment to the Articles of Incorporation of Arizona Public Service Company, amended May 16, 2012	3.1 to Pinnacle West/APS May 22, 2012 Form 8-K Report, File Nos. 1-8962 and 1-4473	5/22/2012
3.4	APS	Arizona Public Service Company Bylaws, amended as of December 16, 2008	3.4 to Pinnacle West/APS December 31, 2008 Form 10-K Report, File No. 1-4473	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, File No. 1-8962	6/20/2017
4.2	Pinnacle West APS	Indenture dated as of January 1, 1995 among APS and The Bank of New York Mellon, as Trustee	4.6 to APS's Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report, File No. 1-4473	1/11/1995
4.3	Pinnacle West APS	Indenture dated as of November 15, 1996 between APS and The Bank of New York, as Trustee	4.5 to APS's Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report, File No. 1-4473	11/22/1996
4.4	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
4.4(a)	Pinnacle West	Fourth Supplemental Indenture dated as of June 17, 2020	4.1 to Pinnacle West June 10, 2020 Form 8-K Report, File No. 1-8962	6/16/2020

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
4.4(b)	Pinnacle West	Fifth Supplemental Indenture dated as of June 10, 2024	4.1 to Pinnacle West June 5, 2024 Form 8-K Report, File No. 1-8962	6/10/2024
4.5	Pinnacle West	Indenture dated as of December 1, 2000 between the Company and The Bank of New York, as Trustee, relating to Subordinated Unsecured Debt Securities	4.2 to Pinnacle West's Registration Statement No. 333-52476	12/21/2000
4.6	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 January 13, 1998 Form 8-K Report, File No. 1-4473	1/16/1998
4.6(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 May 7, 2003 Form 8-K Report, File No. 1-4473	5/9/2003
4.6(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 August 17, 2005 Form 8-K Report, File No. 1-4473	8/22/2005
4.6(c)	APS	Tenth Supplemental Indenture dated as of August 1, 2006	4.1 to APS's July 31, 2006 Form 8-K Report, File No. 1-4473	8/3/2006
4.6(d)	Pinnacle West APS	Twelfth Supplemental Indenture dated as of August 25, 2011	4.6f to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6(e)	Pinnacle West APS	Thirteenth Supplemental Indenture dated as of January 13, 2012	4.6g to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6(f)	Pinnacle West APS	Fourteenth Supplemental Indenture dated as of January 10, 2014	4.6h to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6(g)	Pinnacle West APS	Seventeenth Supplemental Indenture dated as of May 19, 2015	4.1 to Pinnacle West/APS May 14, 2015 Form 8-K Report, File Nos. 1-8962 and 1-4473	5/19/2015
4.6(h)	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, File Nos. 1-8962 and 1-4473	11/6/2015
4.6(i)	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, File Nos. 1-8962 and 1-4473	5/6/2016
4.6(j)	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, File Nos. 1-8962 and 1-4473	9/20/2016
4.6(k)	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, File Nos. 1-8962 and 1-4473	9/11/2017
4.6(l)	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, File Nos. 1-8962 and 1-4473	8/9/2018

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
4.6(m)	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, File Nos. 1-8962 and 1-4473	2/28/2019
4.6(n)	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, File Nos. 1-8962 and 1-4473	8/16/2019
4.6(o)	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, File Nos. 1-8962 and 1-4473	11/20/2019
4.6(p)	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, File Nos. 1-8962 and 1-4473	5/22/2020
4.6(q)	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, File Nos. 1-8962 and 1-4473	9/11/2020
4.6(r)	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, File Nos. 1-8962 and 1-4473	8/16/2021
4.6(s)	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, File Nos. 1-8962 and 1-4473	11/8/2022
4.6(t)	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, File Nos. 1-8962 and 1-4473	6/30/2023
4.6(u)	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, File Nos. 1-8962 and 1-4473	5/9/2024
4.7	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, File No. 1-8962	11/25/2008
4.8	Pinnacle West	Agreement, dated March 29, 1988, relating to the filing of instruments defining the rights of holders of long-term debt not in excess of 10% of the Company's total assets	4.1 to Pinnacle West's 1987 Form 10-K Report, File No. 1-8962	3/30/1988
4.8(a)	Pinnacle West APS	Agreement, dated March 21, 1994, relating to the filing of instruments defining the rights of holders of APS long-term debt not in excess of 10% of APS's total assets	4.1 to APS's 1993 Form 10-K Report, File No. 1-4473	3/30/1994
4.9	Pinnacle West APS	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934		
4.10	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, File No. 1-8962	6/6/2024

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.1(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's September 30, 1991 Form 10-Q Report, File No. 1-4473	11/14/1991
10.1(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's 1994 Form 10-K Report, File No. 1-4473	3/30/1995
10.1(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's 1994 Form 10-K Report, File No. 1-4473	3/30/1995
10.1(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's 1996 Form 10-K Report, File No. 1-4473	3/28/1997
10.1(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's 1996 Form 10-K Report, File No. 1-4473	3/28/1997
10.1(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's March 31, 2002 Form 10-Q Report, File No. 1-8962	5/15/2002
10.1(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's March 2002 Form 10-Q Report, File No. 1-8962	5/15/2002
10.1(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's 2003 Form 10-K Report, File No. 1-8962	3/15/2004
10.1(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's 2003 Form 10-K Report, File No. 1-8962	3/15/2004
10.1(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, File Nos. 1-8962 and 1-4473	5/9/2007
10.1(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, File Nos. 1-8962 and 104473	5/9/2007

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.1(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, File No. 1-8962	3/26/1992
10.1(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's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
10.1(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's 1994 Form 10-K Report, File No. 1-4473	3/30/1995
10.1(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's June 30, 1996 Form 10-Q Report, File No. 1-4473	8/9/1996
10.1(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's 1996 Form 10-K Report, File No. 1-4473	3/28/1997
10.1(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's March 31, 2002 Form 10-Q Report, File No. 1-8962	5/15/2002
10.1(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's March 31, 2002 Form 10-Q Report, File No. 1-8962	5/15/2002
10.1(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's 2003 Form 10-K Report, File No. 1-8962	3/15/2004
10.1(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's 2007 Form 10-K Report, File No. 1-8962	2/27/2008
10.2(1)[b]	Pinnacle West APS	Arizona Public Service Company Deferred Compensation Plan, as restated, effective January 1, 1984, and the second and third amendments thereto, dated December 22, 1986, and December 23, 1987, respectively	10.4 to APS's 1988 Form 10-K Report, File No. 1-4473	3/8/1989

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.2(1)(a)[b]	Pinnacle West APS	Third Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993	10.3A to APS's 1993 Form 10-K Report, File No. 1-4473	3/30/1994
10.2(1)(b)[b]	Pinnacle West APS	Fourth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective as of May 1, 1993	10.2 to APS's September 30, 1994 Form 10-Q Report, File No. 1-4473	11/10/1994
10.2(1)(c)[b]	Pinnacle West APS	Fifth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective January 1, 1997	10.3A to APS's 1996 Form 10-K Report, File No. 1-4473	3/28/1997
10.2(1)(d)[b]	Pinnacle West APS	Sixth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective January 1, 2001	10.8A to Pinnacle West's 2000 Form 10-K Report, File No. 1-8962	3/14/2001
10.2(2)[b]	Pinnacle West APS	Arizona Public Service Company Directors' Deferred Compensation Plan, as restated, effective January 1, 1986	10.1 to APS's June 30, 1986 Form 10-Q Report, File No. 1-4473	8/13/1986
10.2(2)(a)[b]	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's 1993 Form 10-K Report, File No. 1-4473	3/30/1994
10.2(2)(b)[b]	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's September 30, 1994 Form 10-Q Report, File No. 1-4473	11/10/1994
10.2(2)(c)[b]	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's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2(3)[b]	Pinnacle West APS	Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans dated August 1, 1996	10.14A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2(3)(a)[b]	Pinnacle West APS	First Amendment dated December 7, 1999 to the Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans	10.15A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2(4)[b]	Pinnacle West APS	Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan as amended and restated effective January 1, 1996	10.10A to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.2(4)(a)[b]	Pinnacle West APS	First Amendment effective as of January 1, 1999, to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.7A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2(4)(b)[b]	Pinnacle West APS	Second Amendment effective January 1, 2000 to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.10A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2(4)(c)[b]	Pinnacle West APS	Third Amendment to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan, effective as of January 1, 2002	10.3 to Pinnacle West's March 31, 2003 Form 10-Q Report, File No. 1-8962	5/15/2003
10.2(4)(d)[b]	Pinnacle West APS	Fourth Amendment to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan, effective January 1, 2003	10.64b to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
10.2(5)[b]	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, File Nos. 1-8962 and 1-4473	2/19/2016
10.3(1)[b]	Pinnacle West APS	Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan, amended and restated as of January 1, 2003	10.7A to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962	3/15/2004
10.3(1)(a)[b]	Pinnacle West APS	Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan, as amended and restated, dated December 18, 2003	10.48b to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
10.3(2)[b]	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, File Nos. 1-8962 and 1-4473	2/19/2016
10.3(2)(a)[b]	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, File Nos. 1-8962 and 1-4473	2/24/2017

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.3(2)(b)[b]	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, File Nos. 1-8962 and 1-4473	2/23/2018
10.4(1)[b]	Pinnacle West APS	Offer of Employment Letter dated July 19, 2018 between Pinnacle West and Robert E. Smith	10.4.5 to Pinnacle West/APS 2019 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/21/2020
10.4(2)[b]	Pinnacle West APS	Supplemental Agreement dated October 17, 2018 between Pinnacle West and Robert E. Smith	10.4.6 to Pinnacle West/APS 2019 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/21/2020
10.4(3)[b]	Pinnacle West APS	Discretionary Credit Award Agreement dated June 19, 2019 between Pinnacle West and Theodore Geisler	10.4.4 to Pinnacle West/APS 2020 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.4(8)[b]	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, File Nos. 1-8962 and 1-4473	2/27/2023
10.4(9)[b]	Pinnacle West APS	Discretionary Credit Award Agreement dated June 21, 2019 between APS and Jacob Tetlow	10.4(9) to Pinnacle West/APS 2022 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/27/2023
10.4(10)[b]	Pinnacle West APS	First Amendment to Discretionary Credit Award Agreement dated February 21, 2021 between APS and Jacob Tetlow	10.4(10) to Pinnacle West/APS 2022 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/27/2023
10.5(1)[bd]	Pinnacle West APS	Key Executive Employment and Severance Agreement between Pinnacle West and certain executive officers of Pinnacle West and its subsidiaries	10.77bd to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
10.5(1)(a)[bd]	Pinnacle West APS	Form of Amended and Restated Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.4 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File Nos. 1-8962 and 1-4473	11/6/2007
10.5(2)[bd]	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.3 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File Nos. 1-8962 and 1-4473	11/6/2007
10.5(3)[bd]	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.5.3 to Pinnacle West/APS 2009 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/19/2010
10.5(4)[bd]	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.5.4 to Pinnacle West/APS 2012 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/22/2013
10.5(5)[bd]	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, File Nos. 1-8962 and 1-4473	8/5/2021

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.6(1)[b]	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, File No. 1-8962	4/20/2007
10.6(1)(a)[b]	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, File No. 1-8962	4/20/2007
10.6(1)(b)[bd]	Pinnacle West APS	Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.3 to Pinnacle West/APS March 31, 2009 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/5/2009
10.6(1)(c)[bd]	Pinnacle West	Form of Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.1 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962	8/3/2010
10.6(1)(d)[bd]	Pinnacle West	Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.2 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962	8/3/2010
10.6(1)(e)[bd]	Pinnacle West	Form of Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.4 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File No. 1-8962	4/29/2011
10.6(1)(f)[bd]	Pinnacle West	Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.5 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File No. 1-8962	4/29/2011
10.6(1)(g)[bd]	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, File No. 1-8962	4/29/2011
10.6(2)[b]	Pinnacle West	Description of Annual Stock Grants to Non-Employee Directors	10.1 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File No. 1-8962	11/6/2007
10.6(3)[b]	Pinnacle West	Description of Annual Stock Grants to Non-Employee Directors	10.2 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-8962	8/7/2008
10.6(4)[bd]	Pinnacle West APS	Summary of 2025 Variable Incentive Plan and Officer Variable Incentive Plan		
10.6(5)[b]	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, File No. 1-8962	3/29/2012
10.6(5)(a)[bd]	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, File No. 1-8962	3/31/2017
10.6(5)(b)[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.1 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/3/2012

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.6(5)(c)[bd]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.2 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/3/2012
10.6(5)(d)[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.8c to Pinnacle West/APS 2013 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/21/2014
10.6(5)(e)[bd]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.8d to Pinnacle West/APS 2013 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/21/2014
10.6(5)(f)[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.6e to Pinnacle West/APS 2015 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/19/2016
10.6(5)(g)[bd]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.6f to Pinnacle West/APS 2016 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2017
10.6(5)(h)[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.6g to Pinnacle West/APS 2016 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2017
10.6(5)(i)[bd]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.2 to Pinnacle West/APS March 31, 2019 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/1/2019
10.6(5)(j)[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.3 to Pinnacle West/APS March 31, 2019 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/1/2019
10.6(5)(k)[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.1 to Pinnacle West/APS March 31, 2020 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/8/2020
10.6(5)(l)[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.5k to Pinnacle West/APS 2020 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.6(5)(m)[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.5l to Pinnacle West/APS 2020 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.6(5)(n)[bd]	Pinnacle West APS	Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan	Appendix A to the Proxy Statement for Pinnacle West's 2021 Annual Meeting of Shareholders, File No. 1-8962	4/01/2021
10.6(5)(o)[bd]	Pinnacle West	First Amendment to the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan	Appendix A to the Proxy Statement for Pinnacle West's 2022 Annual Meeting of Shareholders, File No. 1-8962	5/19/2023

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.6(5)(p)[bd]	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, File Nos. 1-8962 and 1-4473	2/25/2022
10.6(5)(q)[bd]	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, File Nos. 1-8962 and 1-4473	2/25/2022
10.6(5)(r)[bd]	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, File Nos. 1-8962 and 1-4473	2/25/2022
10.6(5)(s)[bd]	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, File Nos. 1-8962 and 1-4473	2/25/2022
10.6(5)(t)[bd]	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, File Nos. 1-8962 and 1-4473	2/25/2022
10.6(5)(u)[bd]	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, File Nos. 1-8962 and 1-4473	2/25/2022
10.6(5)(v)[bd]	Pinnacle West	Master Amendment to Performance Share Agreements	10.3 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/3/2012
10.6(5)(w)[bd]	Pinnacle West	Master Amendment to Restricted Stock Unit Agreements	10.4 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/3/2012
10.7(1)	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
10.7(1)(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
10.7(1)(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. 1-89	7/25/1985
10.7(1)(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, File Nos. 1-8962 and 1-4473	4/29/2011
10.7(1)(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, File Nos. 1-8962 and 1-4473	4/29/2011
10.7(2)	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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.7(2)(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
10.7(3)	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
10.7(3)(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
10.7(4)	Pinnacle West APS	Four Corners Project Co-Tenancy Agreement, conformed copy up through and including Amendment No. 11, dated June 30, 2018, among APS, Public Service Company of New Mexico, SRP, Tucson Electric Power Company and Navajo Transitional Energy Company, LLC	10.7.4c to Pinnacle West/APS June 30, 2018 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/3/2018
10.7(4)(a)	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, File Nos. 1-8962 and 1-4473	8/5/2021
10.8(1)	Pinnacle West APS	Indenture of Lease, Navajo Units 1, 2, and 3	5(g) to APS's Form S-7 Registration Statement, File No. 2-36505	3/23/1970
10.8(2)	Pinnacle West APS	Application of Grant of rights-of-way and easements, Navajo Plant	5(h) to APS Form S-7 Registration Statement, File No. 2-36505	3/23/1970
10.8(3)	Pinnacle West APS	Water Service Contract Assignment with the United States Department of Interior, Bureau of Reclamation, Navajo Plant	5(l) to APS's Form S-7 Registration Statement, File No. 2-394442	3/16/1971
10.8(4)	Pinnacle West APS	Navajo Project Co-Tenancy Agreement dated as of March 23, 1976, and Supplement No. 1 thereto dated as of October 18, 1976, Amendment No. 1 dated as of July 5, 1988, and Amendment No. 2 dated as of June 14, 1996; Amendment No. 3 dated as of February 11, 1997; Amendment No. 4 dated as of January 21, 1997; Amendment No. 5 dated as of January 23, 1998; Amendment No. 6 dated as of July 31, 1998	10.107 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
10.8(5)	Pinnacle West APS	Navajo Project Participation Agreement dated as of September 30, 1969, and Amendment and Supplement No. 1 dated as of January 16, 1970, and Coordinating Committee Agreement No. 1 dated as of September 30, 1971	10.108 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.9(1)	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's 1988 Form 10-K Report, File No. 1-4473	3/8/1989
10.9(1)(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's March 31, 1991 Form 10-Q Report, File No. 1-4473	5/15/1991
10.9(1)(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's June 30, 2000 Form 10-Q Report, File No. 1-8962	8/14/2000
10.9(1)(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, File Nos. 1-8962 and 1-4473	2/18/2011
10.9(1)(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, File Nos. 1-8962 and 1-4473	5/2/2014
10.10(1)	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's June 30, 1991 Form 10-Q Report, File No. 1-4473	8/8/1991
10.10(2)	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's June 30, 1991 Form 10-Q Report, File No. 1-4473	8/8/1991

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.10(2)(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's 1995 Form 10-K Report, File No. 1-4473	3/29/1996
10.10(3)	Pinnacle West APS	Restated Transmission Agreement between PacifiCorp and APS dated April 5, 1995	10.4 to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996
10.10(4)	Pinnacle West APS	Reciprocal Transmission Service Agreement between APS and PacifiCorp dated as of March 2, 1994	10.6 to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996
10.11(1)	Pinnacle West	Second Amended and Restated Five-Year Credit Agreements dated as of April 10, 2023, among Pinnacle West, as Borrower, Barclays Bank PLC, as Agent, Co-Sustainability Structuring Agent and Issuing Bank, and the lenders and other parties thereto	10.1 to Pinnacle West/APS April 10, 2023 Form 8-K Report, File No. 1-8962	4/10/2023
10.11(1)(a)	Pinnacle West	Amendment No. 1 to the Second Amended and Restated Five-Year Credit Agreement, dated as of April 10, 2023, among Pinnacle West, as Borrower, Barclays Bank PLC, as Agent, Co-Sustainability Structuring Agent and Issuing Bank, and the lenders and other parties thereto	10.1 to Pinnacle West/APS August 2, 2024 Form 8-K Report, File Nos. 1-8962 and 1-4473	8/2/2024
10.11(2)	Pinnacle West APS	Five-Year Credit Agreement dated as of April 10, 2023, among APS, as Borrower, Barclays Bank PLC, as Agent, Co-Sustainability Structuring Agent and Issuing Bank, and the lenders and other parties thereto	10.2 to Pinnacle West/APS April 10, 2023 Form 8-K Report, File No. 1-8962	4/10/2023
10.11(2)(a)	APS	Amendment No. 1 to the Five-Year Credit Agreement, dated as of April 10, 2023, among APS, as Borrower, Barclays Bank PLC, as Agent, Co-Sustainability Structuring Agent and Issuing Bank, and the lenders and other parties thereto	10.2 to Pinnacle West/APS August 2, 2024 Form 8-K Report, File Nos. 1-8962 and 1-4473	8/2/2024
10.12(1)[c]	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's Form 18 Registration Statement, File No. 33-9480	10/24/1986

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.12(1)(a)[c]	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's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8, File No. 1-4473	12/4/1986
10.12(1)(b)[c]	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's 1988 Form 10-K Report, File No. 1-4473	3/8/1989
10.12(1)(c)[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's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
10.12(1)(d)[c]	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, File Nos. 1-8962 and 1-4473	10/30/2015
10.12(1)(e)[c]	Pinnacle West APS	Amendment No. 3, 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 Security Pacific Capital Leasing Corporation, as Lessor, and APS, as Lessee	10.3 to Pinnacle West/APS September 30, 2015 Form 10-Q Report, File Nos. 1-8962 and 1-4473	10/30/2015
10.12(2)	Pinnacle West APS	Facility Lease, dated as of December 15, 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	10.1 to APS's November 18, 1986 Form 8-K Report, File No. 1-4473	1/20/1987

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.12(2)(a)	Pinnacle West APS	Amendment No. 1, dated as of August 1, 1987, to Facility Lease, dated as of December 15, 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	4.13 to APS's Form 18 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report, File No. 1-4473	8/24/1987
10.12(2)(b)	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Facility Lease, dated as of December 15, 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	10.4 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
10.12(2)(c)	Pinnacle West APS	Amendment No. 3, dated July 10, 2014, to Facility Lease, dated as of December 15, 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	10.2 to Pinnacle West/APS June 30, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473	7/31/2014
10.12(2)(d)	Pinnacle West APS	Amendment No. 4, dated April 1, 2021, to Facility Lease, dated as of December 15, 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	10.1 to Pinnacle West/APS March 31, 2021 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/5/2021
10.13(1)	Pinnacle West APS	Agreement between Pinnacle West Energy Corporation and APS for Transportation and Treatment of Effluent by and between Pinnacle West Energy Corporation and APS dated as of the 10th day of April, 2001	10.102 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/16/2005
10.13(2)	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, File Nos. 1-8962 and 1-4473	3/16/2005
10.13(3)	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, File Nos. 1-8962 and 1-4473	3/16/2005
10.13(4)	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, File Nos. 1-8962 and 1-4473	3/16/2005

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.13(5)	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, File Nos. 1-8962 and 1-4473	5/6/2010
10.14(1)	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
10.15(1)	Pinnacle West APS	Territorial Agreement between APS and SRP	10.1 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5/15/1998
10.15(2)	Pinnacle West APS	Power Coordination Agreement between APS and SRP	10.2 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5/15/1998
10.15(3)	Pinnacle West APS	Memorandum of Agreement between APS and SRP	10.3 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5/15/1998
10.15(3)(a)	Pinnacle West APS	Addendum to Memorandum of Agreement between APS and SRP dated as of May 19, 1998	10.2 to APS's May 19, 1998 Form 8-K Report, File No. 1-4473	6/26/1998
10.16(1)	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, File No. 1-8962	3/4/2024
10.16(2)	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, File No. 1-8962	3/4/2024
10.17(1)	Pinnacle West	Forward Sale Agreement, dated February 28, 2024, between Pinnacle West and Mizuho Markets Americas LLC (with Mizuho Securities USA LLC acting as its agent)	10.3 to Pinnacle West February 28, 2024 Form 8-K Report, File No. 1-8962	3/4/2024
10.17(2)	Pinnacle West	Additional Forward Sale Agreement, dated February 28, 2024, between Pinnacle West and Mizuho Markets Americas LLC (with Mizuho Securities USA LLC acting as its agent)	10.4 to Pinnacle West February 28, 2024 Form 8-K Report, File No. 1-8962	3/4/2024
19.1	Pinnacle West	Securities Trading Policy of Pinnacle West		
21.1	Pinnacle West	Subsidiaries of Pinnacle West		
23.1	Pinnacle West	Consent of Deloitte & Touche LLP		
23.2	APS	Consent of Deloitte & Touche LLP		
31.1	Pinnacle West	Certificate of Jeffrey B. Guldner, Chief Executive 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: a	Date Filed
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		
31.3	APS	Certificate of Jeffrey B. Guldner, 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[e]	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[e]	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, File Nos. 1-8962 and 1-4473	2/27/2024
99.1[c]	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's September 30, 1992 Form 10-Q Report, File No. 1-4473	11/9/1992
99.1(a)[c]	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's September 30, 1986 Form 10-Q Report by means of Amendment No. 1, on December 3, 1986 Form 8, File No. 1-4473	12/4/1986

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
99.1(b)[c]	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's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.2[c]	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's Form 18 Registration Statement, File No. 33-9480	10/24/1986
99.2(a)[c]	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, File No. 1-4473	12/4/1986
99.2(b)[c]	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's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.3[c]	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's Form 18 Registration Statement, File No. 33-9480	10/24/1986
99.3(a)[c]	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's September 30, 1986 Form 10-Q Report by means of Amendment No. l on December 3, 1986 Form 8, File No. 1-4473	12/4/1986

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
99.3(b)[c]	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's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.4	Pinnacle West APS	Participation Agreement, dated as of December 15, 1986, among PVGS Funding Report 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 under a Trust Indenture, APS, and the Owner Participant named therein	28.2 to APS's September 30, 1992 Form 10-Q Report, File No. 1-4473	11/9/1992
99.4(a)	Pinnacle West APS	Amendment No. 1, dated as of August 1, 1987, to Participation Agreement, dated as of December 15, 1986, among PVGS Funding Corp., Inc. as Funding Corporation, State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, Chemical Bank, as Indenture Trustee, APS, and the Owner Participant named therein	28.20 to APS's Form 18 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report, File No. 1-4473	8/10/1987
99.4(b)	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of December 15, 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 Owner Participant named therein	28.5 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.5	Pinnacle West APS	Trust Indenture, Mortgage Security Agreement and Assignment of Facility Lease, dated as of December 15, 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	10.2 to APS's November 18, 1986 Form 10-K Report, File No. 1-4473	1/20/1987
99.5(a)	Pinnacle West APS	Supplemental Indenture No. 1, dated as of August 1, 1987, to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 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	4.13 to APS's Form 18 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report, File No. 1-4473	8/24/1987

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
99.5(b)	Pinnacle West APS	Supplemental Indenture No. 2 to Trust Indenture Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 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	4.5 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.6	Pinnacle West APS	Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.5 to APS's November 18, 1986 Form 8-K Report, File No. 1-4473	1/20/1987
99.6(a)	Pinnacle West APS	Amendment No. 1, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.7 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.7[c]	Pinnacle West APS	Indemnity Agreement dated as of March 17, 1993 by APS	28.3 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.8	Pinnacle West APS	Extension Letter, dated as of August 13, 1987, from the signatories of the Participation Agreement to Chemical Bank	28.20 to APS's Form 18 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report, File No. 1-4473	8/10/1987
101.SCH	Pinnacle West APS	XBRL Taxonomy Extension Schema Document		
101.CAL	Pinnacle West APS	XBRL Taxonomy Extension Calculation Linkbase Document		
101.LAB	Pinnacle West APS	XBRL Taxonomy Extension Label Linkbase Document		
101.PRE	Pinnacle West APS	XBRL Taxonomy Extension Presentation Linkbase Document		
101.DEF	Pinnacle West APS	XBRL Taxonomy Definition Linkbase Document		
104	Pinnacle West APS	The Cover Page Interactive Data File (formatted as Inline iXBRL and contained in Exhibit 101)		

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[a]Reports filed under File No. 1-4473 and 1-8962 were filed in the office of the SEC located in Washington, D.C.

[b]Management contract or compensatory plan or arrangement to be filed as an exhibit pursuant to Item 15(b) of Form 10-K.

[c]An additional document, substantially identical in all material respects to this Exhibit, has been entered into, relating to an additional Equity Participant. Although such additional document may differ in other respects (such as dollar amounts, percentages, tax indemnity matters, and dates of execution), there are no material details in which such document differs from this Exhibit.

[d]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.

[e]Furnished herewith as an Exhibit.

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, 2025

/s/ Jeffrey B. Guldner
(Jeffrey B. Guldner, 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 Robert E. Smith, 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/ Jeffrey B. Guldner (Jeffrey B. Guldner, Chairman of the Board of Directors, President and Chief Executive Officer)	Principal Executive Officer and Director	February 25, 2025
/s/ Andrew Cooper (Andrew Cooper, Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 25, 2025
/s/ Elizabeth A. Blankenship (Elizabeth A. Blankenship, Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 25, 2025

/s/ Glynis A. Bryan (Glynis A. Bryan)	Director	February 25, 2025
/s/ Ronald Butler, Jr. (Ronald Butler, Jr.)	Director	February 25, 2025
/s/ Gonzalo A. de la Melena, Jr. (Gonzalo A. de la Melena, Jr.)	Director	February 25, 2025
/s/ Carol S. Eicher (Carol S. Eicher)	Director	February 25, 2025
/s/ Susan T. Flanagan (Susan T. Flanagan)	Director	February 25, 2025
/s/ Richard P. Fox (Richard P. Fox)	Director	February 25, 2025
/s/ Theodore N. Geisler (Theodore N. Geisler)	Director	February 25, 2025
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	February 25, 2025
/s/ Paula J. Sims (Paula J. Sims)	Director	February 25, 2025
/s/ William H. Spence (William H. Spence)	Director	February 25, 2025
/s/ Kristine L. Svinicki (Kristine L. Svinicki)	Director	February 25, 2025
/s/ James E Trevathan, Jr. (James E. Trevathan, Jr.)	Director	February 25, 2025

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, 2025

/s/ Jeffrey B. Guldner
(Jeffrey B. Guldner, Chairman of the Board of Directors 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 Robert E. Smith, 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/ Jeffrey B. Guldner (Jeffrey B. Guldner, Chairman of the Board of Directors and Chief Executive Officer)	Principal Executive Officer and Director	February 25, 2025
/s/ Andrew Cooper (Andrew Cooper, Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 25, 2025
/s/ Elizabeth A. Blankenship (Elizabeth A. Blankenship Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 25, 2025

/s/ Glynis A. Bryan (Glynis A. Bryan)	Director	February 25, 2025
/s/ Ronald Butler, Jr. (Ronald Butler, Jr.)	Director	February 25, 2025
/s/ Gonzalo A. de la Melena, Jr. (Gonzalo A. de la Melena, Jr.)	Director	February 25, 2025
/s/ Carol S. Eicher (Carol S. Eicher)	Director	February 25, 2025
/s/ Susan T. Flanagan (Susan T. Flanagan)	Director	February 25, 2025
/s/ Richard P. Fox (Richard P. Fox)	Director	February 25, 2025
/s/ Theodore N. Geisler (Theodore N. Geisler)	Director	February 25, 2025
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	February 25, 2025
/s/ Paula J. Sims (Paula J. Sims)	Director	February 25, 2025
/s/ William H. Spence (William H. Spence)	Director	February 25, 2025
/s/ Kristine L. Svinicki (Kristine L. Svinicki)	Director	February 25, 2025
/s/ James E Trevathan, Jr. (James E. Trevathan, Jr.)	Director	February 25, 2025