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, 2023

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**			86-0512431
	(an Arizona corporation)			
	400 North Fifth Street, P.O. Box 53999			
	Phoenix	Arizona	85072-3999	
	(602)	250-1000		
1-4473	**ARIZONA PUBLIC SERVICE COMPANY**			86-0011170
	(an Arizona corporation)			
	400 North Fifth Street, P.O. Box 53999			
	Phoenix	Arizona	85072-3999	
	(602)	250-1000		

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	$	9,215,155,738	as of June 30, 2023
ARIZONA PUBLIC SERVICE COMPANY	$	0	as of June 30, 2023

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 21, 2024:	113,427,367
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of February 21, 2024:	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 22, 2024 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	47
Item 1C.	Cybersecurity	48
Item 2.	Properties	50
Item 3.	Legal Proceedings	53
Item 4.	Mine Safety Disclosures	53
Information about our Executive Officers		54
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	87
Item 8.	Financial Statements and Supplementary Data	88
	Pinnacle West Financial Statements	94
	APS Financial Statements	105
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	200
Item 9A.	Controls and Procedures	200
Item 9B.	Other Information	201
Item 9C.	Disclosure Regarding Foreign Jurisdictions that Prevent Inspections	201
PART III		201
Item 10.	Directors, Executive Officers and Corporate Governance of Pinnacle West	201
Item 11.	Executive Compensation	201
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	201
Item 13.	Certain Relationships and Related Transactions, and Director Independence	203
Item 14.	Principal Accountant Fees and Services	203
PART IV		204
Item 15.	Exhibits and Financial Statement Schedules	204
Item 16.	Form 10-K Summary	224
SIGNATURES		225

This combined Form 10-K is separately filed by Pinnacle West and APS. 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.

4CA	4C Acquisition, LLC, a subsidiary of the Company
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
BART	Best available retrofit technology
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
CCR	Coal combustion residuals
Cholla	Cholla Power Plant
DC	Direct Current
DG	Small-scale renewable energy technologies that are located on customers' properties, such as rooftop solar systems
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," and "our" refer to Pinnacle West)
PNW Power	Pinnacle West Power, LLC, a subsidiary of the Company
PPA	Power Purchase Agreement
PSA	Power Supply Adjustor
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
TCA	Transmission cost adjustor

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;
- our ability to manage capital expenditures and operations and maintenance costs while maintaining reliability and customer service levels;
- 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 distributed generation, 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;
- our ability 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;
- current and future economic conditions in Arizona;
- 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;
- 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 the ability to access capital markets when required;
- environmental, economic, and other concerns surrounding coal-fired generation, including regulation of GHG emissions;
- volatile fuel and purchased power costs;

- the investment performance of the assets of our nuclear decommissioning trust, 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;
- the ability to meet the anticipated future need for additional generation and associated transmission facilities in our region;
- the willingness or ability of our 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 that conducts business through its subsidiaries. We derive essentially all of our revenues and earnings from our wholly-owned subsidiary, APS. APS 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 subsidiaries are El Dorado, PNW Power, and 4CA. 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.

BUSINESS OF ARIZONA PUBLIC SERVICE COMPANY

APS currently provides electric service to approximately 1.4 million customers. We own or lease 6,491 MW of regulated generation capacity and we hold a mix of both long-term and short-term purchased power agreements for additional capacity. During 2023, no single purchaser or user of energy accounted for more than 2.1% of our electric revenues.

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

2212051 8.5x11_2022_Service_Territory_Map_FL.jpg

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 2023 were as follows:

1943

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

The share of APS's energy supply being derived from clean resources was approximately 51% in 2023, which includes energy from nuclear, renewables and DSM.

Clean Energy Focus Initiatives

In response to climate change, the entire electric utility industry, as well as the global economy, is in the midst of a profound transition to clean energy and a new low-carbon economy. 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 solar, wind, geothermal, biogas, and biomass. 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 commitment 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 comprehensive 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 disposal of spent nuclear fuel.

The Palo Verde participants have contracted for 100% of Palo Verde's requirements for uranium concentrates through 2028 and 48% through 2029; 100% of Palo Verde's requirements for conversion services through 2029 and 75% through 2030; 100% of Palo Verde's requirements for enrichment services through 2026 and 28% for 2027; 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 submitted nine claims pursuant to the terms of the August 18, 2014 settlement agreement, for nine separate time periods during July 1, 2011 through October 31, 2022. The DOE has approved and paid $138.2 million for these claims (APS's share is $40.2 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, 2023, APS filed its tenth claim pursuant to the terms of the August 18, 2014, settlement agreement in the amount of $18.46 million (APS's share is $5.4 million). In February 2024, the DOE approved $18.39 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 (discussed below); 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.

Ocotillo was originally a 330 MW 4-unit gas plant located in Tempe. In early 2014, APS announced a project to modernize the plant, which involved retiring two older 110 MW steam units, adding five 102 MW combustion turbines, and maintaining two existing 55 MW combustion turbines. In total, this increased the capacity of the site by 290 MW to 620 MW. The Ocotillo modernization project was completed in 2019.

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. As part of APS's Clean Energy Commitment, APS has committed 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 (the "2016 Coal Supply Agreement").

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, 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.

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 381 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 purchases all of Cholla's coal requirements from a coal supplier that mines all of the coal under long-term leases of coal reserves with the federal and state governments and private landholders. The Cholla coal contract runs through 2024. In addition, APS has a coal transportation contract that runs through 2024.

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. Two of our large customers purchase renewable energy credits from APS that are equivalent to the amount of renewable energy that Red Rock is projected to generate.

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.

Renewable Energy Portfolio

To date, APS has a diverse portfolio of existing and planned renewable resources totaling 5,010 MW, including solar, wind, geothermal, biomass and biogas. Of this portfolio, 3,072 MW are currently in operation and 1,938 MW are under contract for development or are under construction. Renewable resources in operation include 415 MW of facilities owned by APS, 1,034 MW of long-term purchased power agreements, and an estimated 1,623 MW of customer-sited, third-party owned distributed energy resources.

On June 30, 2023, APS issued an All-Source Request for Proposal ("RFP") seeking approximately 1,000 MW of reliable capacity, including at least 700 MW of renewable resources with a focus on in-service dates between 2026 and 2028 (the "2023 RFP"). Bids from the 2023 RFP were received on September 6, 2023, and APS has started negotiations on multiple projects, including a 400 MW wind facility PPA that was signed in December 2023.

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 December 31, 2023. 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**	
Distributed Energy:					
APS Owned (a)	**AZ**	**Various**		**37**	
Total APS Owned				**415**	**—**
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**	
CO Bar Solar C	**Coconino County, AZ**	**2025**	**20**		**206**
Mesquite Solar 5	**Tonopah, AZ**	**2023**	**20**	**60**	
Sunstreams 3	**Arlington, AZ**	**2024**	**20**		**215**
Sunstreams 4	**Arlington, AZ**	**2025**	**20**		**300**
Harquahala Sun	**Tonopah, AZ**	**2025**	**20**		**300**
Serrano Solar	**Pima and Pinal County, AZ**	**2025**	**20**		**170**
Yuma Solar Energy	**Yuma County, AZ**	**2024**	**20**		**70**
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**	**2025**	**20**		**400**
Geothermal:					
Salton Sea	**Imperial County, CA**	**2006**	**23**	**10**	
Biomass:					
Snowflake	**Snowflake, AZ**	**2008**	**25**	**14**	

(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 DC and is converted to AC 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.

As noted above, on June 30, 2023, APS issued the 2023 RFP seeking approximately 1,000 MW of reliable capacity, including at least 700 MW of renewable resources, including energy storage, with a focus on in-service dates between 2026 and 2028.

APS currently plans to install more than 2,700 MW of utility scale energy storage by 2026, including through energy storage projects under PPAs and AZ Sun retrofits as well as through resources solicited through current and future RFPs.

The following table summarizes the resources in APS's energy storage portfolio that are in operation and under development as of December 31, 2023. 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	182	(a)	19	(b)
PPAs Energy Storage	60		2,182	
Customer-Sited Energy Storage	30		20	
Total Energy Storage Portfolio	**272**		**2,221**	

(a) Includes 0.3 MW of APS-owned customer-sited batteries.
(b) Includes 19 MW of capacity that entered commercial operation in January 2024.

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 December 31, 2023, 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	570
Renewable Energy (b)	Various	1,063

(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. Renewable energy purchased power agreements are described in detail below under "Current and Future Resources — Renewable Energy Standard."

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 2023 peak one-hour demand on its electric system was recorded on July 15, 2023, at 8,162 MW, compared to the 2022 peak of 7,587 MW recorded on July 11, 2022. APS's reserve margin at the time of the 2023 peak demand, calculated using system load serving capacity, was 18%. For 2024, due to expiring purchased power contracts, 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. APS was originally required to file its IRP by August 1, 2023. However, on May 1, 2023, APS, Tucson Electric Company, and UNS Electric, Inc., filed a joint request to extend the IRP filing due date to November 1, 2023, which the ACC granted on June 21, 2023. APS filed its 2023 IRP on November 1, 2023. On January 31, 2024, stakeholders filed comments regarding the IRP. APS cannot predict the outcome of this matter. On October 4, 2023, the ACC updated the IRP processing timeline with a due date of August 30, 2024 for the ACC Staff Assessment and Proposed Order and an open meeting decision due date yet to be determined.

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 & 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 is participating in market design and tariff development of Markets+, a day-ahead and real-time market offering from Southwest Power Pool. APS also participated in the design and drafting of the tariff for the CAISO’s Extended Day-Ahead Market, which was approved by FERC in December 2023. In addition, APS is participating in the Western Resource Adequacy Program administered by Western Power Pool. These efforts are driven by three objectives of reducing customer cost, improving reliability, and incorporating more clean energy on APS’s system.

Energy Modernization Plan

On July 30, 2020, the ACC Staff issued final draft energy rules, which proposed 100% of retail kWh sales from clean energy resources by the end of 2050. Nuclear power was defined as a clean energy resource. The proposed rules also required 50% of retail energy served be renewable by the end of 2035. On November 13, 2020, the ACC approved a final draft energy rules package which required additional procedural steps in the rulemaking process. 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 Order and Opinion, 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 RFP requirements and the IRP process. During the August 2022 ACC Open Meeting, the ACC voted to postpone a decision on the All-Source RFP 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. 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 adopted 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 solar, wind, biomass, biogas, and geothermal technologies. The renewable energy requirement is 13% of retail electric sales in 2023 and increases annually until it reaches 15% in 2025.

A component of the RES is focused on stimulating development of DG systems. Accordingly, under the RES, an increasing percentage of that requirement must be supplied from distributed energy resources. This distributed renewable energy requirement, which was waived by the ACC as a part of APS's 2023 RES Implementation Plan, would have been 30% of the overall RES requirement of 13% in 2023. On June 7, 2021, the ACC approved the 2021 RES Implementation Plan. On July 1, 2021, APS filed its 2022 RES Implementation Plan, which was subsequently amended on December 9, 2021. 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 September 23, 2022, APS filed a community solar proposal in compliance with the ACC order that was informed by a stakeholder working group. APS proposed a small, pilot scale program size of up to 140 MW that would be selected through a competitive RFP. The ACC has not yet ruled on the proposal. However, on November 10, 2022, the ACC approved a bifurcated community solar process, directing ACC Staff to develop a statewide policy through additional stakeholder involvement and establishing a separate evidentiary hearing to define other policy components. On March 23, 2023, the ACC approved a policy statement that included information on how statewide community solar and storage programs should be structured, their location, and inclusion in RFPs. The remainder of the community solar program policy components were deferred to the ACC's Hearing Division so that a formal evidentiary hearing could be held to consider issues of substance related to community solar. APS cannot predict the outcomes of these future activities.

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. The following table summarizes the RES requirement standard and its timing:

	2023	2025
RES (inclusive of distributed energy) as a percent of retail electric sales	13%	15%
Percent of RES to be supplied from distributed renewable energy resources (a)	30%	30%

(a) The distributed renewable energy requirement has been waived for 2023.

On April 21, 2015, the RES rules were amended to require utilities to report on all eligible renewable resources in their service territory, irrespective of whether the utility owns renewable energy credits associated with such renewable energy. The rules allow the ACC to consider such information in determining whether APS has satisfied the requirements of the RES.

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 May 9, 2013, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. The ACC subsequently opened a docket for this matter and received comments from a number of interested parties on the considerations involved in establishing retail electric deregulation in the state. One of these considerations was whether various aspects of a deregulated market, including setting utility rates on a "market" basis, would be consistent with the requirements of the Arizona Constitution. On September 11, 2013, after receiving legal advice from the ACC Staff, the ACC voted 4-1 to close the current docket and await full Arizona Constitutional authority before any further examination of this matter. The motion approved by the ACC also included opening one or more new dockets in the future to explore options to offer more rate choices to customers and innovative changes within the existing cost-of-service regulatory model that could include elements of competition.

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. 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. APS cannot predict what impact, if any, this change will have on APS.

On August 4, 2021, Green Mountain Energy filed an application seeking a certificate of convenience and necessity to allow it to provide competitive electric generation service in Arizona. Green Mountain Energy has requested that the ACC grant it the ability to provide competitive service in APS's and Tucson Electric Power Company's certificated service territories and proposes to deliver a 100% renewable energy product to residential and general service customers in those service territories. APS opposes Green Mountain Energy's application. On November 3, 2021, the ACC submitted questions to the Arizona Attorney General, Civil Litigation Division, Consumer Protection & Advocacy Section ("Attorney General") requesting legal opinions related to a number of issues surrounding retail electric competition and the ACC's ability to issue competitive certificates convenience and necessity. On November 26, 2021, the Administrative Law Judge issued a procedural order indicating it would not be appropriate to set a schedule until the Attorney General has provided insights on the applicable law. As the ACC's questions pertained to the retail competition law subsequently repealed in April 2022, the Attorney General has not responded to the ACC's request and the questions are now moot. No action has been taken by the ACC regarding this application since that time. However, on May 17, 2023, the Retail Energy Supply Association filed a motion with the ACC requesting it to re-open the generic docket to re-examine the ACC's electric competition rules. No action has been taken by the ACC regarding this motion. APS cannot predict the outcome of these matters.

On October 28, 2021, an ACC Commissioner docketed a letter directing ACC Staff and interested stakeholders to design a 200 to 300 MW pilot program that would allow residential and small commercial customers of APS to elect a competitive electricity supplier. The letter also states that similar programs should be designed for other Arizona regulated electric utilities. APS cannot predict the outcome of these future activities.

Wholesale

FERC regulates rates for wholesale power sales and transmission services. See Note 3 for information regarding APS's transmission rates. During 2023, approximately 7.4% 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. This Ten-Year 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 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 under consideration in the 118th 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 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.

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 latest set of proposed rules, released on May 23, 2023, EPA contemplates 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, the most recent proposal is limited to measures that can be installed at individual power plants to limit planet-warming emissions.

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”) or varying levels of hydrogen gas (“H2”) co-firing. As for existing natural gas-fired combustion turbines, EPA is imposing similar control requirements at large, high utilization generating units, but is otherwise not proceeding at this time with further regulation. Under EPA’s proposal, this means that both new and existing peaking gas-fired combustion turbines (i.e., those with a 20% or less annual capacity factor) are effectively unregulated under the proposed regulations.

For coal-fired power plants, instead of imposing regulations based on capacity and utilization, EPA has developed subcategories based on planned retirement dates. This means that facilities retiring between 2030 and before 2040 must meet increasingly stringent emission limits up to natural-gas co-firing starting in 2030. However, for those facilities with no planned retirement date prior to 2040, EPA is requiring those plants to be retrofitted with CCS controls by 2030.

At this time, APS cannot predict the outcome of this rulemaking or when EPA will take final action. In addition, APS is continuing to evaluate this proposal and its potential impact on APS’s operations. Depending on the eventual outcome, the costs associated with APS’s operation of its current and future thermal power plants could materially increase, which could affect our financial condition, results of operations, or cash flows.

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 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. Although ADEQ has taken steps to develop a CCR permitting program, and new state legislation has been adopted providing ADEQ with appropriate permitting authority for CCR under the state solid waste management program, it is not clear when that program will be put into effect. 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. On January 11, 2022, EPA began issuing proposed decisions pursuant to this provision of the federal CCR regulations and APS anticipates receiving a proposed decision with respect to the Cholla facility in 2024.

- On May 18, 2023, EPA published a proposal that expands the scope of federal CCR regulations to address the impacts from historical CCR disposal activities that would have ceased prior to 2015. EPA proposes to define a new class of CCR management units ("CCRMUs") that 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. EPA expects to finalize this proposal by spring of 2024.

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.

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. To comply with the CCR rule for the Navajo Plant, APS's share of incremental costs was approximately $1 million, which has been incurred. 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 by April 11, 2021, at the latest (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 will also solicit input from the public and host 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 in Note 11. 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, APS cannot predict any ultimate impacts to the APS; however, at this time, APS does not believe that any potential changes to the cost estimate for Four Corners or Cholla would have a material impact on our financial condition, results of operations, or cash flows.

Effluent Limitation Guidelines. Based on the most recently finalized effluent limitation guidelines ("ELG"), published by EPA on October 13, 2020, APS completed an NPDES permit modification for Four Corners on December 1, 2023. The ELG standards finalized in October of 2020 relaxed the "zero discharge" standard for bottom ash transport waters EPA finalized in September of 2015. Nonetheless, on March 29, 2023, EPA proposed again for the bottom ash transport water ELG to shift back to a "zero discharge" standard. EPA anticipates finalizing these standards by spring or summer of 2024. In the event these standards are finalized as proposed, a further modification to the Four Corners NPDES permit would be required. We cannot at this time predict the outcome of this rulemaking nor whether future regulatory action by EPA would have impacts 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. We anticipate that revisions to the SIPs and FIPs implementing required controls to achieve the new 70 ppb standard will be in place between 2023 and 2024. 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.

On March 15, 2023, EPA issued its final Good Neighbor Plan for 23 states in order to ensure that the cross-state transport of ozone forming emissions does not interfere with downwind state compliance with the NAAQS. Power plant emission limitations are a key aspect of these regulations, which involve emission allowance trading for nitrogen oxide emissions. While Arizona was not among the 23 states subject to EPA's March 2023 final action, EPA announced at this time that it was considering the inclusion of Arizona within a future regulatory action under the "good neighbor" provisions of the Clean Air Act.

APS cannot at this time predict the outcome of future "good neighbor" rulemakings by EPA or the extent to which such regulations, if they are finalized, may impact our financial condition, results of operations, or cash flows.

Superfund-Related Matters. The Comprehensive Environmental Response Compensation and Liability Act ("CERCLA" or "Superfund") 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. APS cannot predict the EPA's timing with respect to this matter. APS estimates that its cost related to this investigation and study is approximately $3 million. APS anticipates incurring additional expenditures in the future, but because the ultimate remediation requirements are not yet finalized by EPA, 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, which is on appeal to the U.S. Court of Appeals for the Ninth Circuit based on a U.S. District Court order dismissing cost recovery claims of approximately $20.7 million by a service provider for RID. 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 our financial condition, results of operations, or cash flows.

In addition, as part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, the ADEQ sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. Since that time, ADEQ has taken no action based on the information provided by APS.

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 our 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, 2024, Arizona's supply of Colorado River water will be subject to a Tier 1 shortage. This shortage will result in a reduction to Arizona's share of the Colorado River water by 28 percent or 792,000-acre feet. This reduction will largely be felt by central Arizona's agricultural users, mainly in Pinal County. In light of pre-existing mitigation measures at the state level, the Tier 1 shortage is not expected at this time to materially impact water supplies for customers in APS's service territory, nor 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.

Assured supplies of water are important for APS's generating plants. At the present time, APS has adequate water to meet its operating needs. The Four Corners region, in which Four Corners is located, has historically experienced drought conditions that may affect the water supply for the plants if adequate moisture is not received in the watershed that supplies the area. APS is continuing to work with area stakeholders to implement agreements to minimize the effect, if any, on future drought conditions that could have an impact on operations of its plants.

Conflicting claims to limited amounts of water in the southwestern United States have resulted in numerous court actions, which, in addition to future supply conditions, have the potential to impact APS's operations.

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 a number of 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 and is a party to a shortage sharing agreement, which provides for the apportionment of water supplies to 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 seeks to attract the best employees, retain those employees, and create a safe, inclusive, and productive work environment for all employees. We believe the strength of our employees is one of the significant contributors to our Company's success. Human capital measures and objectives that the Company focuses on in retaining its talent and managing its business include the safety of our employees, career development, diversity, equity and inclusion, succession planning, hiring, voluntary turnover, compensation, benefits, employee experience, and engagement.

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 safety practices and programs that ensure employees have safe and secure workplaces that allow them to perform at the highest levels. We use preventative programs such as the APS Moves program to help our workforce stay 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. Our employees are expected to do the right thing and are empowered to speak up when there are better or safer ways of doing business, including stopping work to reassess or improve safety. Safety committees operate in organizations throughout the Company, providing opportunities for employees to positively impact their local safety cultures and performance.

Inclusion and Belonging

We believe that belonging matters. When we feel seen, heard, and valued, we can more effectively unite behind the APS Promise. Inclusion at the Company involves taking deliberate action to embrace the unique perspectives of each employee. We recognize that diversity of demographics, backgrounds and cultural perspective is a key driver for our success. Our internal diversity, equity, and inclusion team, supported by our Executive Diversity & Inclusion Council as well as other groups, leads this commitment with an emphasis on diversity among employees, in the workplace, and through our community involvement, as well as an increased focus on attracting and retaining diverse talent. This focus extends to individual business units in the Company, which report on the diversity of their teams during management review meetings to build awareness and address gaps of workforce diversity.

Our efforts to support and empower employees include a commitment to full inclusion of all our people. We have a robust, multi-year strategy for diversity, equity, and inclusion that focuses on eleven key areas, both internally- and externally-facing. In 2021, APS received recognition as winner of the Inclusive Workplace Award from Diversity Leadership Alliance and Arizona Society of Human Resource Management. The award recognizes APS as an Arizona corporation that leads by example, creating an inclusive environment in which employees can be their genuine, authentic selves, and partners on community outreach efforts and support.

Each year since 2020, we have conducted company-wide executive listening sessions to provide employees with opportunities to be heard on their experiences at the Company. In 2019, we signed the UNITY Pledge in support of full inclusion and equality in employment, housing, and public accommodations for all Arizonans, including gay and transgender people. The UNITY Pledge reinforces our commitment to fostering an environment that recognizes our employees' unique needs and celebrates the value of diverse perspectives. The Company sponsors eleven employee network groups that are intended to create a sense of inclusion and belonging for employees.

We continue to focus on hiring diverse employees as well as hiring employees from our veteran community. During 2023, 42% of external hires were ethnically or racially diverse, 35% were female and 8% were veterans. Additionally, as of December 31, 2023, 35% of our employees are ethnically or racially diverse, 26% are female, and 14% are veterans. Finally, as of December 31, 2023, 39% of the Company's officers are female, and 18% are ethnically or racially diverse.

Succession Planning

Succession planning ensures that our Company is prepared to fill executive and other key leadership roles with capable, experienced employees who can lead us into the future with strong and sustainable performance. We continually revisit and revise succession plans to make certain qualified individuals are in place to move into critical positions. In addition, we provide each business unit of the Company with talent management strategies and development plans to meet its future leadership needs. Effective succession planning helps us identify employees with leadership potential, evaluate any gaps in education, skills and experience, and support employees in preparation for their next leadership roles. Officers and directors review succession plans, leadership opportunities, and retirement projections to ensure business continuity.

Talent Strategy and Development

We place significant focus on attracting and developing a skilled workforce. To attract and retain top talent, we provide formal professional development programs through blended learning education and leadership training. Our employees have access to a wide variety of training and development opportunities, including leadership academies, rotational programs, mentoring programs, industry certifications, and loaned executive programs. In 2023, we graduated 152 individuals from our three academies (Leadership Academy, Impact and Influence Academy, and Strategic Leadership Academy).

Talent pipelines help sustain our skilled workforce needs. Our pipeline strategy is driven by a robust portfolio of programs aimed at attracting early and mid-career talent. With over a dozen programs in effect, our talent pipelines include craft apprenticeships and engineering, rotational, and internship programs. We partner closely with specific colleges and universities, vocational schools, and organizations serving local communities to attract a large pool of qualified, diverse talent. Additionally, 2023 marked the launch of the Department of Defense SkillBridge program, which provides APS early access to transitioning military talent to fill open roles.

During 2023, we hosted 57 summer interns with an overall diversity rate of 67% and also comprised of 35% women. In addition to our summer program, 14 participated as Maintenance Interns, Radiation Protection Interns, and Pre-Apprentice Interns (programs specifically offered at Palo Verde).

Total Rewards Strategy

In addition to our talent strategy, we place significant focus on our Total Rewards strategy for attracting, developing, and rewarding our highly skilled workforce. Our employees are important to the success and future of our organization and our customers' experiences. At the Company, our pay and benefits, along with retirement, recognition, time off, career development and well-being, make up our Total Rewards program. It is an important part of the employee experience at the Company and supports personal well-being and professional satisfaction. We are committed to providing programs that matter to our employees throughout various life and career phases.

Employee Engagement

An annual employee experience survey and focused quarterly pulse-surveys, enable us to gather employee feedback, identify opportunities for improvement, and compare our performance to other companies. Through the surveys, we track our Employee Experience Index, a set of seven questions that encompass key elements of a positive employee experience, including recognition, career development possibilities, and pride in the organization. Based on survey results, business units and individual managers are encouraged to take meaningful actions to improve the employee experience. In response to past surveys, we have launched enterprise-wide initiatives focused on improving communication between employees and management as well as removing obstacles that prevent job success. Other initiatives driven by the survey have given employees more access to leadership and improved meeting efficiency. Our cross-functional Employee Engagement Council focuses on improving employee recognition across the organization. We work to ensure that a positive work environment is maintained for all employees. Through an outreach initiative, we obtain feedback from new hires regarding their employee experience.

Company Culture

In 2020, the Company launched the APS Promise, anchoring 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.

Item 1.jpg

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. 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 Pinnacle West Power, LLC ("PNW Power"), a newly-formed, 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.

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 $16.7 million has been funded as of December 31, 2023. 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 $6.3 million has been funded as of December 31, 2023. 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.

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

Pinnacle West, APS and El Dorado are all incorporated in the State of Arizona. PNW Power is incorporated in Delaware. Additional information for each of these companies is provided below:

	Principal Executive Office Address	Year of Incorporation	Approximate Number of Employees at December 31, 2023	
Pinnacle West	400 North Fifth Street Phoenix, AZ 85004	1985	81	
APS	400 North Fifth Street P.O. Box 53999 Phoenix, AZ 85072-3999	1920	6,045	
BCE	400 East Van Buren Street Phoenix, AZ 85004	2014	7	(a)
El Dorado	400 East Van Buren Street Phoenix, AZ 85004	1983	—	
Total			6,133	

(a) See Note 20 for information related to the sale of Bright Canyon Energy.

The APS number includes employees at jointly-owned generating facilities (approximately 2,200 employees) for which APS serves as the generating facility manager. Approximately 1,150 APS employees are union employees, represented by the 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. This new contract has a duration of three years and becomes amendable on April 1, 2026.

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, 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. In November 2021, the Arizona Court of Appeals issued an opinion that called into question the ACC-approved limitation of liability provision found in the APS Service Schedules. APS sought review of the decision at the Arizona Supreme Court, which was denied; however, the Supreme Court depublished portions of the Court of Appeals' decision. APS is seeking revised tariff language to mitigate potential adverse impacts on APS's future, potential litigation exposure which may result from this court decision. 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. 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 currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. 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. Following a U.S. Supreme Court decision on June 30, 2022, which substantially narrowed EPA's authority to regulate power plant GHG emissions under the Clean Air Act, on May 23, 2023, EPA proposed new GHG emission standards for power plants. In contrast to measures finalized in 2015, EPA's May 2023 proposal is focused on limiting power plant GHG emissions through control mechanisms that can be implemented at individual power plant facilities. These mechanisms would include carbon capture and sequestration, hydrogen co-firing, natural gas co-firing, and limits on facility output, among other measures. EPA expects to take final action on this proposal in the spring or summer of 2024.

Depending on the outcome of future 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 1999, the ACC approved rules for the introduction of retail electric competition in Arizona. Retail competition could have a significant adverse financial impact on APS due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. Although some very limited retail competition existed in APS's service area in 1999 and 2000, there are currently no active retail competitors offering unbundled energy or other utility services to APS's customers. This is in large part due to a 2004 Arizona Court of Appeals decision that found critical components of the ACC's rules to be violative of the Arizona Constitution. The ruling also voided the operating authority of all the competitive providers previously authorized by the ACC. On May 9, 2013, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. The ACC subsequently opened a docket for this matter and received comments from a number of interested parties on the considerations involved in establishing retail electric deregulation in the state. One of these considerations is whether various aspects of a deregulated market, including setting utility rates on a "market" basis, would be consistent with the requirements of the Arizona Constitution. On September 11, 2013, after receiving legal advice from the ACC staff, the ACC voted 4-1 to close the current docket and await full Arizona Constitutional authority before any further examination of this matter.

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.

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 forest fires. Forest fires could threaten APS's communities and electric transmission lines and facilities. Any damage caused as a result of forest fires 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 (this requirement has been waived by the ACC for 2023). 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. Retail customers in APS's service territory increased 2.0% for the year ended December 31, 2023, compared with the prior-year period. For the three years through 2023, APS's customer growth averaged 2.1% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2024 and the average annual growth to be in the range of 1.5% to 2.5% through 2026 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 1.5% for the year ended December 31, 2023, 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 customers.

For the three years through 2023, annual retail electricity sales growth averaged 2.7%, 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 2.0% to 4.0% for 2024 and that average annual growth will be in the range of 4.0% to 6.0% through 2026, 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 2024 growth in the range of 2.5% to 3.5% and to average annual growth in the range of 3.0% to 5.0% through 2026.

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 their future extra-large projects (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 $20 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 $5 million.

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 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 California. The continued expansion of the wildland urban interface has also increased wildfire risk to surrounding communities. APS currently intends to implement a public safety power shutoff ("PSPS") program in addition to its current fire mitigation efforts. While such technology is intended to mitigate fire risk, it also introduces additional risks to APS and its customers, such as claims for damages, and the timing and effectiveness of such fire mitigation efforts may be insufficient to prevent wildfires in APS's expansive service territory and surrounding areas. APS could be held liable for damages incurred as a result of wildfires regardless of fault 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 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 $22.4 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. 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 28% of employees eligible to retire by the end of 2028. 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.

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, from 2021 to 2023, the United States' economy has experienced a substantial rise in the inflation rate. There is increased uncertainty as to whether the rise in inflation will continue and for how long. Increases in inflation raise the Company's costs for commodities, labor, materials and services. Additionally, global supply chains have been impacted, resulting in equipment delays and increased costs. A failure to recover the increased costs caused by increased inflation and supply chain constraints 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 2023 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. 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, the top risks affecting the Company are identified. For 2023, cybersecurity was identified as a top 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, 2023 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	387
Total Steam					1,357
Combined Cycle:					
Redhawk	2		Gas	Load Following	1,088
West Phoenix	5		Gas	Load Following	887
Total Combined Cycle					1,975
Combustion Turbine:					
Ocotillo (d)	7		Gas	Peaking	620
Saguaro	3		Gas	Peaking	189
Douglas	1		Oil	Peaking	16
Sundance	10		Gas	Peaking	420
West Phoenix	2		Gas	Peaking	110
Yucca 1, 2, 3	3		Gas	Peaking	93
Yucca 4	1		Oil	Peaking	54
Yucca 5, 6	2		Gas	Peaking	96
Total Combustion Turbine					1,598
Solar:					
Cotton Center (e)	1		Solar	As Available	17
Hyder I (e)	1		Solar	As Available	17
Paloma (e)	1		Solar	As Available	17
Chino Valley	1		Solar	As Available	20
Gila Bend (e)	1		Solar	As Available	36
Hyder II (e)	1		Solar	As Available	14
Foothills (e)	1		Solar	As Available	38
Luke AFB	1		Solar	As Available	11
Desert Star (e)	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	37
Multiple facilities			Solar	As Available	4
Total Solar					415
Total Capacity					6,491

(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 & 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) Ocotillo Steam Units 1 and 2 were retired on January 10, 2019. Units 3 through 7 all went into service on or prior to May 30, 2019, which increased generation capacity by 510 MW.
(e) APS is under contract and currently plans to add battery storage at these AZ Sun sites. See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Energy Storage" above for details related to these and other energy storage 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 February 1, 2024, APS's transmission facilities consist of approximately 5,832 pole miles of overhead lines and approximately 85 miles of underground lines, 5,772 miles of which are located in Arizona. APS's distribution facilities consist of approximately 11,289 miles of overhead lines and approximately 23,604 miles of underground primary cable (20,508 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, 2023:

	Percent Owned (Weighted-Average)	
Morgan — Pinnacle Peak System	63.2	%
Palo Verde — Rudd 500kV System	50.0	%
Round Valley System	50.0	%
ANPP 500kV System	33.4	%
Navajo Southern System	25.2	%
Four Corners Switchyards	57.5	%
Palo Verde — Yuma 500kV System	25.3	%
Phoenix — Mead System	17.1	%
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 2024 Ten-Year Plan, APS projects it will develop 109 miles of new transmission lines over the next 10 years. Additionally, APS plans to upgrade 730 miles of existing transmission lines over the same horizon. The 2024 Ten-Year Plan includes a new 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 2024 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 2024 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 27, 2024, current positions and principal occupations for the past five years are as follows:

Name	Age	Position	Period
Jeffrey B. Guldner	58	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	52	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	45	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	49	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	45	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	60	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	46	Vice President and Treasurer of Pinnacle West and APS	2022-Present
		Vice President, Finance and Planning of Pinnacle West and APS	2020-2022
		General Manager, Finance of Pinnacle West	2017-2020
Robert E. Smith	54	Executive Vice President, General Counsel and Chief Development Officer of Pinnacle West and APS	2021-Present
		Senior Vice President and General Counsel of Pinnacle West and APS	2018-2021
Jacob Tetlow	51	Executive Vice President, Operations of APS	2021-Present
		Senior Vice President, Non-Nuclear Operations of APS	2020-2021
		Vice President, Transmission and Distributions Operations of APS	2017-2020

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 21, 2024, Pinnacle West's common stock was held of record by approximately 14,476 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, 2023, 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, 2023, 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, 2018, in Pinnacle West's common stock and in each of the indices shown and that all of the dividends were reinvested.

Stock.jpg

	Year Ended December 31,					
Company/ Index	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Pinnacle West Common Stock	$100	$109	$101	$93	$105	$104
Edison Electric Institute Index	$100	$126	$124	$146	$147	$134
S&P 500 Index	$100	$131	$156	$200	$164	$207

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 2023 results with 2022 results. For the discussion of 2022 compared to 2021, 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, 2022, 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 $25 billion. For over 130 years, 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.

Inflation Reduction Act of 2022

On August 16, 2022, President Biden signed the Inflation Reduction Act of 2022 ("IRA"). The 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; and (iii) introduction of a new PTC for nuclear energy produced by existing nuclear energy plants ("Nuclear PTC"), available from 2024 through 2032. The Internal Revenue Service and U.S. Treasury have issued preliminary guidance related to various provisions of the IRA that have enabled APS to claim credits related to its 2023 solar and battery 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 in future years.

In addition, the IRA contains several provisions which could create additional tax liabilities for corporations, including a 15% corporate alternative minimum tax for corporations with net profits in excess of $1 billion and a 1% excise tax on stock buybacks. We currently do not believe the Company will be subject to any material tax liabilities as a result of these legislative provisions.

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

Recognizing that creating customer value is inextricably linked to increasing shareholder value, 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, while demonstrating compassion and advocacy for its customers. This multi-year objective includes incrementally improving APS's J.D. Power ("JDP") overall customer satisfaction ratings to achieve a first quartile ranking in its peer set comprised of large investor-owned utilities. APS has made noteworthy progress on that front.

As previously disclosed, APS's JDP Residential rankings for overall customer satisfaction improved in each of 2020, 2021, and 2022, and have improved again in 2023. At the end of 2023, APS's residential customer satisfaction ranked in the second quartile among large investor-owned utilities, and its business customer satisfaction ranked in the second quartile of utilities nationally.

Reliable

While our energy mix evolves, APS's obligation 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 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 residential and commercial energy needs, APS has developed a future-focused, strategic transmission plan. This Ten-Year 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 Plan, are intended to 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 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 best-in-class 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. APS also currently intends to implement a public safety power shutoff ("PSPS") program for this upcoming fire season, leveraging the additional real-time analysis provided by the new modelling software. We continue to evaluate policy and regulatory options, as well as insurance programs, to mitigate the impact of wildfire events.

Maintaining reliability and affordability for our customers during the clean energy transition is fundamental to our strategy. As a critical partner to the large quantity of renewables and energy storage we are adding to our system, natural gas generation will play an important role in maintaining reliability for our customers. One example is the 2019 addition of new natural gas units at the modernized Ocotillo Power Plant to provide cleaner-running and more efficient units. Additionally, efficiency improvements to gas units at the Redhawk and Sundance Power Plants are planned for completion prior to the summer of 2024.

As part of a balanced energy portfolio, these flexible resource additions support reliability by responding quickly to the variability of solar generation and delivering energy in the late afternoon and early evening when solar production declines as the sun sets and customer demand peaks. Complementary to and in support of the transition to renewable resources, APS continues to evaluate options to meet growing energy demand and ensure grid reliability, including through upgrades to and/or modernization of additional existing natural gas facilities.

In October 2021, APS announced plans to evaluate regional market solutions as part of the informal Western Markets Exploratory Group ("WMEG"). As a member of WMEG, APS is exploring 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 state regulations. WMEG hopes to identify market solutions that can help achieve carbon reduction goals while supporting reliable, affordable service for customers. APS is unable to predict the outcome of these discussions.

APS will go live with a new Energy Management System ("EMS") in March of 2024. The new EMS will better allow for integration of the renewable and energy storage assets into the APS's generation resources. This integration will allow APS to maximize the flexibility of our resources and fully engage in the Energy Imbalance Market. It also better positions APS to participate in market opportunities that may develop through the next decade.

APS's key elements to delivering reliable power include resource planning, sufficient reserve margins, customer partnerships to manage peak demand, fire mitigation, and operational preparedness. Seasonal readiness procedures at APS also 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 on fire and emergency management with federal, state, and local agencies.

Affordable

APS continues to focus on mitigating the cost pressures related to the current inflationary environment. Overall inflation grew by 2.7% in Phoenix and 3.4% nationally during 2023. In 2022, overall inflation grew by 9.5% in Phoenix and 6.5% nationally. The impacts from inflation have varied across separate categories of APS's spending, including increases of up to 15% in 2023. APS has seen inflationary impacts in supply constrained categories related to electrical equipment, such as transformers, wire, and cable impacted by high utility demand outpacing manufacturing capacity. Inflation continues to impact service rates and spend categories through pass-through costs such as supplier's increased material costs, cost of insurance, and wage rates.

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 Western Energy Imbalance Market ("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 is participating in market design and tariff development of Markets+, a day-ahead and real-time market offering from Southwest Power Pool. APS also participated in the design and drafting of the tariff for the CAISO's Extended Day-Ahead Market, which was approved by FERC in December 2023. In addition, APS is participating in the Western Resource Adequacy Program administered by Western Power Pool. These efforts are driven by three objectives of reducing customer cost, improving reliability, and incorporating more clean energy on APS's system.

In terms of generation affordability, every three years, APS performs a comprehensive study, called an Integrated Resource Plan, to identify how much energy our customers will need over the next 15 years and what resources will be used to meet those needs. In developing the IRP, APS considers factors that include how much economic growth is expected, what new technologies might be available and how weather can impact the demand for energy. These inputs are then used to develop a plan that prioritizes reliability, affordability, and a clean, balanced energy mix.

In November 2023, APS released its latest IRP, which shows that energy demand is growing at an unprecedented rate. This is due to continued residential and commercial customer growth throughout Arizona. To keep pace with the fast-growing demand for electricity and maintain reliability, APS needs to add new electricity generating resources. To ensure that the most affordable and reliable solutions are selected, APS issued All-Source Request for Proposals ("RFPs") in 2022 and 2023. These RFPs are open to all technologies, including customer-scale (behind the meter) and utility-scale (front of the meter) resources. Through this process, APS has consistently found that clean resources like wind and solar, when coupled with energy storage technology, are among the most affordable options available today. Over the long term, these resources are expected to provide the greatest value as part of a diverse energy mix.

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 commitment 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 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's 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 24% lower in 2022 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 (see Note 3 for additional information) establishes the path to meeting our clean energy commitment and maintaining reliable electric service for our customers. APS intends to strengthen its already diverse energy mix by increasing its investments in carbon-free resources. Our IRP rapidly adds clean energy and storage resources while maintaining reliable and affordable service. Its near-term actions are focused on clean, reliable energy and positive customer outcomes and include: (a) competitive all source requests for proposal ("RFPs") that provide an on-ramp to procure additional clean energy resources such as solar, wind, energy storage, and DSM resources, all of which lead to a cleaner grid and (b) strategic, short-term wholesale market purchases from a combination of existing merchant natural gas units, neighboring utility systems and wholesale market participants that ensure operational reliability.

APS has a diverse portfolio of existing and planned renewable resources, including solar, wind, 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 resource, 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 facilities, procurement of new facilities to be owned by APS, and the ongoing development of distributed energy resources. This balance will ensure an appropriately diverse portfolio designed to achieve the same operational reliability and customer affordability as APS's near-term strategies. In addition, APS is actively seeking to include future facility purchase options in its PPAs that will enable investments with greater financial flexibility.

APS uses competitive "all source" RFPs to pursue market 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. Available projects are guided by IRP timelines and quantities and APS maintains a flexible approach that allows it to optimize system reliability and customer affordability through the RFP process. 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.

On June 30, 2023, APS issued an RFP (the "2023 RFP") seeking approximately 1,000 MW of reliable capacity, including at least 700 MW of renewable resources with a focus on in-service dates between 2026 and 2028. Bids from the 2023 RFP were received on September 6, 2023, and APS has started negotiations on multiple projects, including a 400 MW wind facility PPA that was signed in December 2023.

The following table summarizes the resources in APS's renewable energy portfolio that are in operation or under development as of December 31, 2023. 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	415	—	
PPAs Renewables:			
Solar	370	1,261	
Wind	637	616	
Geothermal	10	—	
Biomass	14	—	
Biogas	3	—	
Total PPAs	1,034	1,877	
Total Distributed Energy: Solar (a)	1,623	61	(b)
Total Renewable Portfolio	3,072	1,938	

(a) Includes rooftop solar facilities owned by third parties. Distributed generation 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.

As noted above, on June 30, 2023, APS issued the 2023 RFP seeking approximately 1,000 MW of reliable capacity, including at least 700 MW of renewable resources, including energy storage, with a focus on in-service dates between 2026 and 2028.

APS currently plans to install more than 2,700 MW of utility scale energy storage by 2026, including through energy storage projects under PPAs and AZ Sun retrofits as well as through resources solicited through current and future RFPs.

The following table summarizes the resources in APS's energy storage portfolio that are in operation and under development as of December 31, 2023. 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	182	(a)	19	(b)
PPAs Energy Storage	60		2,182	
Customer-Sited Energy Storage	30		20	
Total Energy Storage Portfolio	**272**		**2,221**	

(a) Includes 0.3 MW of APS-owned customer-sited batteries.
(b) Includes 19 MW of capacity that entered commercial operation in January 2024.

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

Electric Vehicles

As a part of the statewide transportation electrification plan ("TE Plan") approved by the ACC in 2021, APS has a goal of supporting 450,000 light-duty electric vehicles ("EV") in its service territory by 2030. In furtherance of this goal, through its Take Charge AZ Pilot Program, and as of December 31, 2023, APS installed 758 Level 2 charging ports at 183 customer locations and DC fast charging stations that are owned and operated by APS at five locations in Arizona. In December 2023, the ACC voted to discontinue the Take Charge AZ Pilot Program ("TCAZ") while allowing APS to complete projects that were already underway.

Additionally, as part of APS's DSM Plan, APS launched an Electric Vehicle Charging Demand Management Pilot Program to proactively address the growing electric demand from charging as EVs become more widely adopted. The EV related programs in the DSM Plan also include the APS SmartCharge data gathering program, Fleet Advisory Services, and a $100 rebate to home builders for new homes to be built EV-ready with 240V charging station garage outlets. APS filed its 2024 DSM Plan on November 30, 2023. The 2024 DSM Plan includes APS's 2024 TE Plan and, among other things, proposes two new programs: an expanded residential EV Charging Demand Management Program, and a Commercial EV Make-Ready Program. The ACC has yet to decide on the 2024 DSM Plan.

Hydrogen Production

On May 12, 2022, Arizona's three public universities, along with four Arizona energy providers, including APS, announced the formation of a new, interdisciplinary coalition, called the Arizona Center for a Carbon Neutral Economy ("AzCaNE"), with the goal of achieving a carbon neutral economy in Arizona. AzCaNE's first action was to pursue an Arizona-led approach to securing regional clean hydrogen hub

funding. Leading professionals from the seven founding participants, along with representatives of Arizona, the Navajo Nation and companies working to develop a hydrogen ecosystem within Arizona, make up the Governance Committee for AzCaNE's efforts. AzCaNE submitted an initial hydrogen hub concept paper to the DOE, which in turn encouraged the submission of a full application for funding. In response, AzCaNE formed the Southwest Clean Hydrogen Innovation Network ("SHINe") and submitted an application for funding its behalf. SHINe was not, however, selected as one of the seven regional hubs to be awarded funding by DOE. APS is currently maintaining a participatory role in AzCaNE as the organization continues to explore ways to educate stakeholders and promote low-carbon technologies.

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, particularly in regard to EPA's proposed Greenhouse Gas (GHG) rule. On May 23, 2023, the EPA proposed regulations for GHG emissions that would, among other things, require CCUS technologies for certain classifications of coal-, oil-, and natural gas-fired electricity generating units dependent upon a variety of factors including retirement date and operating capacity. See Note 10 for more information.

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.

The Sustainability Department engaged the Electric Power Research Institute ("EPRI") and leveraged input from employees, large customers, limited-income advocates, economic development groups, environmental non-governmental organizations, leading sustainability academics and other stakeholders to identify and assess the sustainability issues that matter most. In total, 23 Priority Sustainability Issues ("PSIs") were identified and prioritized. The most critical category includes four issues deemed most important and most able to be impacted by our actions: clean energy, customer experience, energy access and reliability, and safety and health. These PSIs provide the foundation for informing our strategic direction, creating a framework for incorporating best practices and driving enterprise-wide alignment and accountability. The Company also benchmarked best practices within the top four PSIs and has utilized this information to identify opportunities for improvement.

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 emergence of artificial intelligence technology risk 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 will assess both the opportunities and risks during the technology intake process to ensure compliance with data security and reliability requirements, while observing market trends in this rapidly evolving area.

Regulatory Overview

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 the date rates become effective ("Day 1") of a net $460 million. This Day 1 net impact represents a total base revenue deficiency of $772 million offset by proposed adjustor transfers of cost recovery to annual retail rates and adjustor mechanism modifications. The average annual customer bill impact of APS's request on Day 1 is an increase of 13.6%.

The principal provisions of APS's application were:

- a test year comprised of twelve months ended June 30, 2022, adjusted as described below;
- an original cost rate base of $10.5 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure		Cost of Capital	
Long-term debt	48.07	%	3.85	%
Common stock equity	51.93	%	10.25	%
Weighted-average cost of capital			7.17	%

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- a rate of $0.038321 per kWh for the portion of APS's retail base rates attributable to fuel and purchased power costs;
- modification of its adjustment mechanisms including:
  - eliminate the Environmental Improvement Surcharge ("EIS") and collect costs through base rates,
  - eliminate the Lost Fixed Cost Recovery ("LFCR") mechanism and collect costs through base rates and the Demand Side Management Adjustment Charge ("DSMAC"),
  - maintain as inactive the Tax Expense Adjustor Mechanism ("TEAM"),
  - maintain the Transmission Cost Adjustment ("TCA") mechanism,
  - modify the performance incentive in the DSMAC, and
  - modify the Renewable Energy Adjustment Charge ("REAC") to include recovery of capital carrying costs of APS owned renewable and storage resources;
- changes to its limited-income program, including a second tier to provide an additional discount for customers with greater need; and

- twelve months of post-Test Year plant investments to reflect used and useful projects that will be placed into service prior to July 1, 2023.

On June 5, 2023 and June 15, 2023, the ACC Staff, the Residential Utility Consumer Office ("RUCO") and other intervenors filed their initial written testimony with the ACC. The ACC Staff recommends among other things, (i) a $251 million revenue increase or, as an alternative, a $312 million revenue increase, (ii) a 9.6% return on equity, (iii) a 0.0% fair value increment or, as an alternative, a 0.75% fair value increment, and (iv) a continuation of a 12-month post-test year plant. RUCO recommends, among other things, (i) an $84.9 million revenue increase, (ii) an 8.2% return on equity or, as an alternative, an 8.7% return on equity if the ACC imputes a hypothetical capital structure with a 46% equity layer, (iii) a fair value increment of 0.0%, and (iv) a reduction of post-test year plant to six months.

On July 12, 2023, APS filed rebuttal testimony addressing the ACC Staff and intervenors' direct testimonies. The principal provisions of APS's rebuttal testimony were:

- reducing the revenue requirement increase to $383.1 million, which reduced the average annual customer bill impact to an increase of 11.3%;
- maintaining a return on equity request of 10.25%;
- reducing the increment of fair value rate base return to 0.5% from 1.0%;
- maintaining a post-test year plant request of 12 months, plus the Four Corners Effluent Limitation Guidelines ("ELG") project;
- withdrawing the Payment Fee Removal Proposal (net reduction) which was originally requested in APS's initial application;
- maintaining the LFCR and DSMAC as separate adjustors;
- increasing the PSA annual rate change limit from $0.004/kWh to $0.006/kWh;
- proposing a new System Reliability Benefit ("SRB") recovery mechanism;
- maintaining the REAC in its current state;
- maintaining adjustor base transfers and elimination of EIS; and
- maintaining the request to recover CCT funding.

On July 26, 2023, the ACC Staff, RUCO and other intervenors filed their surrebuttal testimony with the ACC. The ACC Staff adjusted their initial recommendations to, among other things, (i) a $281.9 million revenue increase, (ii) a 9.68% return on equity, (iii) a 0.5% fair value increment, (iv) a continuation of a 12-month post-test year plant that includes the Four Corners ELG project, and (v) support of an increase to the annual PSA increase limit to $0.006/kWh. RUCO maintained their direct position and also recommended further review of the PSA in a second phase of the 2022 Rate Case.

On August 4, 2023, APS filed rejoinder testimony addressing the ACC Staff and intervenors' surrebuttal testimonies. APS's rejoinder testimony included final post-Test Year Plant values, reducing the revenue requirement increase to $377.7 million from $383.1 million, which reduced the average annual customer bill impact to an increase of 11.2%. All other major provisions from APS's rebuttal testimony were maintained in its rejoinder testimony.

On November 6, 2023, and November 21, 2023, APS and stakeholders filed briefs in the 2022 Rate Case. APS's briefs included the reduction of the total revenue requirement increase to $376.2 million and a resulting average annual customer bill impact increase of 11.1%. All other major provisions from APS's rejoinder testimony were maintained in its briefs. ACC Staff's briefs included a proposed total revenue requirement increase from $281.9 million to $282.7 million and also included their support of APS's SRB mechanism, contingent on increased stakeholder outreach.

On January 25, 2024, an Administrative Law Judge issued a Recommended Opinion and Order 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 ELG project, (vi) the approval of APS's SRB proposal with certain procedural and other modifications, (vii) no additional 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 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 RFP, and (viii) recovery of all DSM costs through the 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 is expected to issue the final order for the 2022 Rate Case in March 2024 with the new rates to become effective for all service rendered on and after March 8, 2024.

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 Recommended Opinion and Order 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 (the "2019 Rate Case Decision"). See Note 3 for information regarding the 2019 Rate Case ROO.

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 SCR project, a reversal of the 20-basis point 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 of 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. The current CRS will be recalculated at the end of the 2022 Rate Case to remove the effects of the prospective recovery related to the allowable return on equity difference. On February 22, 2024, the ACC approved the 2022 Rate Case. The CRS tariff is currently being recalculated to reflect the final decision in that case. See Note 3 for more information regarding the 2019 Rate Case and Four Corners SCR cost recovery.

The portion of the CRS representing the recovery of the $59.6 million of lost revenue between December of 2021 and June 20, 2023, $9.4 million of which has been collected as of December 31, 2023, will cease upon full collection of the lost revenue. Finally, recovery of ongoing costs related to the SCR investments will continue until the Company's next rate case in which they can be incorporated therein.

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 from utilities and interested parties on ways to reduce regulatory lag, including alternative ratemaking structures such as future test years and hybrid test years. APS filed comments on June 1, 2023. APS cannot predict the outcome of this matter.

See Note 3 for information regarding additional regulatory matters.

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 and BCE. 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. 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 Pinnacle West Power, LLC ("PNW Power"), a newly-formed, wholly-owned subsidiary of Pinnacle West.

The BCE Sale transaction was accounted for as the sale of a business and closed in multiple stages. As of December 31, 2023, all of BCE assets were classified as held for sale. The final closing of the BCE Sale was on January 12, 2024. See Note 20 for additional details.

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.

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 $16.7 million has been funded as of December 31, 2023. 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 $6.3 million has been funded as of December 31, 2023. 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.

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 2021 through 2023, retail electric revenues comprised approximately 91% 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 2.0% for the year ended December 31, 2023, compared with the prior-year period. For the three years through 2023, APS's customer growth averaged 2.1% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2024 and the average annual growth to be in the range of 1.5% to 2.5% through 2026 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 1.5% for the year ended December 31, 2023, 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 customers.

For the three years through 2023, annual retail electricity sales growth averaged 2.7%, 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 2.0% to 4.0% for 2024 and that average annual growth will be in the range of 4.0% to 6.0% through 2026, 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 2024 growth in the range of 2.5% to 3.5% and to average annual growth in the range of 3.0% to 5.0% through 2026.

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 $20 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 $5 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 $15 million; however, extreme weather variations have resulted in larger annual variations in net income.

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 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 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.

Property Taxes. Taxes other than income taxes consist primarily of property taxes, which are affected by 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 10.0% of the assessed value for 2023, 10.2% for 2022, and 10.7% for 2021. Property taxes increased in 2023 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 sales supplied under traditional cost-based rate regulation) and related activities and includes electricity generation, transmission, and distribution. All other segment activities are insignificant. Our regulated electricity segment activities are conducted primarily through our wholly-owned subsidiary, APS.

Operating Results – 2023 compared with 2022

Our consolidated net income attributable to common shareholders for the year ended December 31, 2023, was $502 million, compared with $484 million for the prior year. The results reflect an increase of approximately $18 million, primarily as a result of the effects of weather, higher CRS and LFCR revenue, higher transmission revenue, increased sales and usage, and higher other income. These positive factors were partially offset by higher interest charges, net of AFUDC, higher operations and maintenance expense, lower pension and other postretirement non-service credits, and higher depreciation and amortization expense mostly due to increased plant assets.

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

	APS Consolidated				Pinnacle West Consolidated		
	Year Ended December 31,				Year Ended December 31,		
	2023	2022	Net Change		2023	2022	Net Change
	(dollars in millions)						
Operating revenues	$ 4,696	$ 4,324	$ 372		$ 4,696	$ 4,324	$ 372
Fuel and purchased power expense	(1,793)	(1,629)	(164)		(1,793)	(1,629)	(164)
Operating revenues less fuel and purchased power expenses	2,903	2,695	208		2,903	2,695	208
Operations and maintenance	(1,044)	(974)	(70)		(1,059)	(987)	(72)
Depreciation and amortization	(794)	(753)	(41)		(794)	(753)	(41)
Taxes other than income taxes	(224)	(220)	(4)		(224)	(220)	(4)
Pension and other postretirement non-service credits, net	42	99	(57)		41	98	(57)
Other income and expenses, net	60	22	38		60	(1)	61
Interest charges, net of allowance for borrowed funds used during construction	(285)	(236)	(49)		(331)	(256)	(75)
Income taxes	(94)	(91)	(3)		(77)	(75)	(2)
Less income related to noncontrolling interests	(17)	(17)	—		(17)	(17)	—
Net Income Attributable to Common Shareholders	$ 547	$ 525	$ 22		$ 502	$ 484	$ 18

Operating revenues less fuel and purchased power expenses. Operating revenues less fuel and purchased power expenses were $208 million higher for the year ended December 31, 2023, compared with the prior year. The following table summarizes the major components of this change:

	Increase (Decrease)		
	Operating revenues	Fuel and purchased power expenses	Net change
	(dollars in millions)		
LFCR revenue (Note 3)	$ 55	$ —	$ 55
Effects of weather	46	12	34
CRS revenue (Note 3)	34	—	34
Higher transmission revenues (Note 3)	26	—	26
Higher retail revenue due to customer growth and changes in customer usage patterns and related pricing, partially offset by the impacts of energy efficiency and distributed generation	39	14	25
Higher renewable energy regulatory surcharges, partially offset by operations and maintenance costs	15	(8)	23
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	158	145	13
Miscellaneous items, net	(1)	1	(2)
Total	$ 372	$ 164	$ 208

Operations and maintenance. Operations and maintenance expenses increased $72 million for the year ended December 31, 2023, compared with the prior-year period primarily due to:

- An increase of $31 million primarily related to costs for renewable energy and similar regulatory programs, which are partially offset in operating revenues and purchased power;
- An increase of $22 million related to non-nuclear generation costs primarily due to higher operating costs and higher planned outages;
- An increase of $14 million related to transmission, distribution, and customer service;
- An increase of $13 million related to nuclear generation costs;
- An increase of $10 million related to information technology costs;
- A decrease of $26 million related to employee benefits, largely due to decreased pension and other post-retirement service costs of $12 million and other miscellaneous factors. See "pension and other postretirement non-service credits, net" below for additional discussion; and
- An increase of $8 million for corporate resources and other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $41 million higher for the year ended December 31, 2023, compared to the prior-year period primarily due to increased plant in service.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $57 million lower for the year ended December 31, 2023, compared to the prior-year period primarily due to the effect of higher discount rates and actual market returns being lower than estimated returns in 2022.

Other income and expenses, net. All other income and expenses, net were $61 million higher for the year ended December 31, 2023, compared to the prior-year period primarily due to higher interest income, higher allowance for equity funds used during construction due to increased capital expenditures, Clear Creak wind farm impairment (see Note 10) recorded in the prior year period, and the gain on the BCE Sale. See Note 20. The difference between APS's and Pinnacle West's other income and expenses, net primarily relates to BCE matters.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction were $75 million higher for the year ended December 31, 2023, compared to the prior-year period primarily due to higher debt balances, higher commercial paper balances and higher interest rates in the current period, partially offset by higher allowance for borrowed funds due to increased capital expenditures. The difference between APS's and Pinnacle West's interest charges, net of allowance for borrowed funds used during construction is primarily relates to Pinnacle West's higher term loan interest and BCE debt activity.

Income taxes. Income taxes were $2 million higher for the year ended December 31, 2023, compared with the prior-year period primarily due to higher pre-tax income, partially offset by Investment Tax Credit amortization from our Arizona Sun battery facilities, and Production Tax Credits from our Agave Solar facility, both of which went into service in 2023.

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 requires APS to maintain a common equity ratio of at least 40%. As defined in 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, 2023, APS's common equity ratio, as defined, was 49%. Its total shareholder equity was approximately $7.2 billion, and total capitalization was approximately $14.7 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $5.9 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 and its revolving credit facility. 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. APS is currently authorized to receive up to $150 million annually in equity infusions from Pinnacle West without seeking ACC approval. On October 27, 2023, APS sought approval from the ACC to receive from Pinnacle West in 2024 up to an additional $500 million in equity infusions above the authorized limit of $150 million, and on January 9, 2024, the ACC approved the increased equity infusion limit for 2024.

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 2028. See Note 5.

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, 2023, and 2022 (dollars in millions):

Pinnacle West Consolidated

	2023	2022
Net cash flow provided by operating activities	$ 1,207	$ 1,242
Net cash flow used for investing activities	(1,694)	(1,618)
Net cash flow provided by financing activities	487	371
Net decrease in cash and cash equivalents	$ —	$ (5)

Arizona Public Service Company

	2023	2022
Net cash flow provided by operating activities	$ 1,275	$ 1,230
Net cash flow used for investing activities	(1,687)	(1,549)
Net cash flow provided by financing activities	412	314
Net decrease in cash and cash equivalents	$ —	$ (5)

Operating Cash Flows

2023 Compared with 2022. Pinnacle West's consolidated net cash provided by operating activities was $1,207 million in 2023 compared to $1,242 million in 2022, a decrease of $35 million in net cash provided primarily due to $204 million higher fuel and purchased power costs, $82 million higher payments for operations and maintenance costs, $66 million higher interest payments, $57 million lower customer advances for construction and $13 million change in net collateral, partially offset by $349 million higher cash receipts from electric revenues and $37 million lower income taxes. The difference between APS's and Pinnacle West's net cash provided by operating activities primarily relates to APS's lower 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 110% funded as of January 1, 2024, and was 112% as of January 1, 2023. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. In 2022 and 2023, we did not make any contributions to our pension plan. In 2021, we made contributions to our pension plan totaling $100 million. The minimum required contributions for the pension plan are zero for the next three years and we do not expect to make any voluntary contributions in 2024, 2025 or 2026. Regarding contributions to our other postretirement benefit plan, we did not make any contributions in 2023 or 2022 and do not expect to make any contributions in 2024, 2025 or 2026. The Company was reimbursed $23 million in 2023, $26 million in 2022, and $24 million in 2021 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 102% funded as of December 31, 2023, and our postretirement benefit plans were 162% funded, as measured for GAAP purposes at December 31, 2023. See Note 7 for additional details.

The CARES Act allows employers to defer payments of the employer share of Social Security payroll taxes that would have otherwise been owed from March 27, 2020, through December 31, 2020. We deferred the cash payment of the employer's portion of Social Security payroll taxes for the period July 1, 2020, through December 31, 2020, that was approximately $18 million. As of December 31, 2022, we have paid this cash deferral in full.

Investing Cash Flows

2023 Compared with 2022. Pinnacle West's consolidated net cash used for investing activities was $1,694 million in 2023 compared to $1,618 million in 2022, an increase of $76 million primarily related to increased capital expenditures and higher allowance for borrowed funds, partially offset by proceeds 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.

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,		
	2024	**2025**	**2026**
APS			
Generation:			
Clean:			
Nuclear Generation	$ 130	$ 130	$ 140
Renewables and Energy Storage Systems (“ESS”) (a)	175	305	280
Other Generation (b)	455	320	235
Distribution	565	550	590
Transmission	340	415	420
Other (c)	285	280	385
Total APS	$ 1,950	$ 2,000	$ 2,050

(a) APS Solar Communities program, energy storage, renewable projects, and other clean energy projects.
(b) Includes generation environmental projects.
(c) Primarily information systems and facilities 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. Generation capital expenditures also include additions and improvements to existing fossil plants, such as our current modernization project at our Sundance gas plant. Examples of the types of projects included in the forecast of generation capital expenditures are additions of renewables and energy storage, and upgrades and capital replacements of various nuclear and fossil power plant equipment, such as turbines, boilers, and environmental equipment. 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

2023 Compared with 2022. Pinnacle West's consolidated net cash provided by financing activities was $487 million in 2023 compared to $371 million in 2022, an increase of $116 million in net cash provided primarily due to a net increase in short-term borrowings of $193 million and $117 million lower long-term debt repayments, partially offset by $186 million in lower issuances of long-term debt and higher dividend payments of $8 million.

APS's consolidated net cash provided by financing activities was $412 million in 2023 compared to $314 million in 2022, an increase of $98 million in net cash provided primarily due to a net increase in short-term borrowings of $135 million, partially offset by $29 million in lower issuances of long-term debt and higher dividend payments of $8 million.

Significant Financing Activities. On December 13, 2023, the Pinnacle West Board of Directors declared a dividend of $0.880 per share of common stock, payable on March 1, 2024, to shareholders of record on February 1, 2024. During 2023, Pinnacle West increased its indicated annual dividend from $3.46 per share to $3.52 per share. For the year ended December 31, 2023, Pinnacle West's total dividends paid per share of common stock were $3.48 per share, which resulted in dividend payments of $386 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.

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, 2023, the ratio was approximately 60% for Pinnacle West and 52% 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 15, 2022, the ACC issued a financing order reaffirming the previous 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 APS's application filed April 6, 2022 requesting to increase the long-term debt limit from $7.5 billion to $8.0 billion and to exclude financing lease PPAs from the definition of long-term debt for purposes of the ACC financing orders. See Note 6 for further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of February 15, 2024, are shown below. We are disclosing these credit ratings to enhance understanding of our cost of short-term and long-term capital and our ability to access the markets for liquidity and long-term debt. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS's securities and/or result in an increase in the cost of, or limit access to, capital. Such revisions may also result in substantial additional cash or other collateral requirements related to certain derivative instruments, insurance policies, natural gas transportation, fuel supply, and other energy-related contracts. At this time, we believe we have sufficient available liquidity resources to respond to a potential downward revision to our credit ratings.

	Moody's	Standard & Poor's	Fitch
Pinnacle West			
Corporate credit rating	Baa1	BBB+	BBB+
Senior unsecured	Baa1	BBB	BBB+
Commercial paper	P-2	A-2	F2
Outlook	Negative	Negative	Negative
APS			
Corporate credit rating	A3	BBB+	BBB+
Senior unsecured	A3	BBB+	A-
Commercial paper	P-2	A-2	F2
Outlook	Negative	Negative	Negative

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, 2023. 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.

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 $2,016 million of regulatory assets and $2,176 million of regulatory liabilities on the Consolidated Balance Sheets at December 31, 2023. 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, 2023, reported pension assets and liabilities on the Consolidated Balance Sheets and our 2023 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%	$ (250)	$ (9)
Decrease 1%	295	10
EROA:		
Increase 1%	—	(19)
Decrease 1%	—	19

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant while the rates are changed by one percentage point.

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

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2023, other postretirement benefit obligation on the Pinnacle West's Consolidated Balance Sheets and our 2023 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%	$ (42)	$ (2)
Decrease 1%	51	2
Healthcare cost trend rate (c):		
Increase 1%	42	5
Decrease 1%	(36)	(4)
EROA – pretax:		
Increase 1%	—	(4)
Decrease 1%	—	4

(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, 2023 are described further in Note 11.

OTHER ACCOUNTING MATTERS

See Note 21 for two new accounting standards that were issued in November and December 2023, respectively, that are pending adoption: ASU 2023-07, Improvements to Reportable Segment Disclosures, effective for us for annual periods on December 31, 2024, and interim periods thereafter, and ASU 2023-09, Improvements to Income Tax Disclosures, effective for us for annual periods on December 31, 2025.

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, 2023, and 2022. If variable interest rates were to increase by 10% from the December 31, 2023, 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, 2023, and 2022 (dollars in millions):

Pinnacle West – Consolidated

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2023	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**	**Interest Rates**	**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

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2022	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**
2023	4.56 %	$ 341	5.42 %	$ 51	—	$ —
2024	—	—	5.10 %	450	3.35 %	250
2025	—	—	—	—	1.99 %	800
2026	—	—	—	—	2.55 %	250
2027	—	—	—	—	2.95 %	300
Years thereafter	—	—	3.96 %	163	4.10 %	5,580
Total		$ 341		$ 664		$ 7,180
Fair value		$ 341		$ 664		$ 5,922

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, 2023, and 2022. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2023, and 2022 (dollars in millions):

APS — Consolidated

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

2022	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
2023	4.56 %	$ 325	—	$ —	—	$ —
2024	—	—	—	—	3.35 %	250
2025	—	—	—	—	3.15 %	300
2026	—	—	—	—	2.55 %	250
2027	—	—	—	—	2.95 %	300
Years thereafter	—	—	3.96 %	163	4.10 %	5,580
Total		$ 325		$ 163		$ 6,680
Fair value		$ 325		$ 163		$ 5,466

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, 2023	December 31, 2022
Mark-to-market of net positions at beginning of year	$ 96	$ 107
Decrease (increase) in regulatory asset	(216)	(11)
Mark-to-market of net positions at end of year	$ (120)	$ 96

The table below shows the fair value of maturities of our energy derivative contracts (dollars in millions) at December 31, 2023, 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	2024	2025	2026	2027	2028
Observable prices provided by other external sources	$ (82)	$ (41)	$ (2)	$ —	$ —
Prices based on unobservable inputs	5	—	—	—	—
Total by maturity	$ (77)	$ (41)	$ (2)	$ —	$ —

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, 2023 Gain (Loss)		December 31, 2022 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	$ 9	$ (9)	$ 12	$ (12)
Natural gas	55	(55)	55	(55)
Total	$ 64	$ (64)	$ 67	$ (67)

(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)	89
Report of Independent Registered Public Accounting Firm (PCAOB ID No. 34)	90
Pinnacle West Consolidated Statements of Income for 2023, 2022 and 2021	94
Pinnacle West Consolidated Statements of Comprehensive Income for 2023, 2022 and 2021	95
Pinnacle West Consolidated Balance Sheets as of December 31, 2023 and 2022	96
Pinnacle West Consolidated Statements of Cash Flows for 2023, 2022 and 2021	98
Pinnacle West Consolidated Statements of Changes in Equity for 2023, 2022 and 2021	99
Management’s Report on Internal Control over Financial Reporting (Arizona Public Service Company)	100
Report of Independent Registered Public Accounting Firm (PCAOB ID No. 34)	101
APS Consolidated Statements of Income for 2023, 2022 and 2021	105
APS Consolidated Statements of Comprehensive Income for 2023, 2022 and 2021	106
APS Consolidated Balance Sheets as of December 31, 2023 and 2022	107
APS Consolidated Statements of Cash Flows for 2023, 2022 and 2021	109
APS Consolidated Statements of Changes in Equity for 2023, 2022 and 2021	110
Combined Notes to Consolidated Financial Statements	111
Note 1. Summary of Significant Accounting Policies	111
Note 2. Revenue	119
Note 3. Regulatory Matters	121
Note 4. Income Taxes	140
Note 5. Lines of Credit and Short-Term Borrowings	145
Note 6. Long-Term Debt and Liquidity Matters	147
Note 7. Retirement Plans and Other Postretirement Benefits	151
Note 8. Leases	159
Note 9. Jointly-Owned Facilities	163
Note 10. Commitments and Contingencies	164
Note 11. Asset Retirement Obligations	173
Note 12. Fair Value Measurements	174
Note 13. Earnings Per Share	180
Note 14. Stock-Based Compensation	180
Note 15. Derivative Accounting	184
Note 16. Other Income and Other Expense	188
Note 17. Palo Verde Sale Leaseback Variable Interest Entities	189
Note 18. Investments in Nuclear Decommissioning Trusts and Other Special Use Funds	189
Note 19. Changes in Accumulated Other Comprehensive Loss	193
Note 20. Sale of Bright Canyon Energy	194
Note 21. New Accounting Standards	195

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, 2023. The effectiveness of our internal control over financial reporting as of December 31, 2023, 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 27, 2024

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, 2023 and 2022, 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, 2023, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, 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, 2023, 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 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 and compared to management's recorded regulatory assets and liabilities for completeness.
- We observed the ACC Open Meeting during which the Recommended Order and Opinion regarding the 2022 Retail Rate Case was amended and approved and read the approved 2022 Rate Case Recommended Order and Opinion as amended. We obtained and evaluated management's internally prepared analysis regarding impacts of the approved 2022 Rate Case Recommended Order and Opinion as amended to rates and recorded balances.
- 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 27, 2024

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,		
	2023	2022	2021
OPERATING REVENUES (Note 2)	$ 4,695,991	$ 4,324,385	$ 3,803,835
OPERATING EXPENSES			
Fuel and purchased power	1,792,657	1,629,343	1,152,551
Operations and maintenance	1,058,725	987,072	954,067
Depreciation and amortization	794,043	753,195	650,875
Taxes other than income taxes	224,013	220,370	234,639
Other expenses	1,913	2,494	6,393
Total	3,871,351	3,592,474	2,998,525
OPERATING INCOME	824,640	731,911	805,310
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	53,118	45,263	41,737
Pension and other postretirement non-service credits, net (Note 7)	40,648	98,487	112,541
Other income (Note 16)	33,666	7,916	45,100
Other expense (Note 16)	(25,056)	(52,385)	(25,396)
Total	102,376	99,281	173,982
INTEREST EXPENSE			
Interest charges	374,887	283,569	254,314
Allowance for borrowed funds used during construction (Note 1)	(43,564)	(28,030)	(21,052)
Total	331,323	255,539	233,262
INCOME BEFORE INCOME TAXES	595,693	575,653	746,030
INCOME TAXES (Note 4)	76,912	74,827	110,086
NET INCOME	518,781	500,826	635,944
Less: Net income attributable to noncontrolling interests (Note 17)	17,224	17,224	17,224
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 501,557	$ 483,602	$ 618,720
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	113,442	113,196	112,910
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	113,804	113,416	113,192
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Net income attributable to common shareholders — basic	$ 4.42	$ 4.27	$ 5.48
Net income attributable to common shareholders — diluted	$ 4.41	$ 4.26	$ 5.47

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,		
	2023	**2022**	**2021**
NET INCOME	$ 518,781	$ 500,826	$ 635,944
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized gain, net of tax expense of $234, $615, and $360	713	1,873	1,095
Pension and other postretirement benefits activity, net of tax benefit (expense) of $801, $(7,078), and $(2,256) (Note 7)	(2,422)	21,553	6,840
Total other comprehensive income (loss)	(1,709)	23,426	7,935
COMPREHENSIVE INCOME	517,072	524,252	643,879
Less: Comprehensive income attributable to noncontrolling interests	17,224	17,224	17,224
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 499,848	$ 507,028	$ 626,655

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

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

	December 31,	
	2023	2022
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 4,955	$ 4,832
Customer and other receivables	513,892	453,209
Accrued unbilled revenues	167,553	164,764
Allowance for doubtful accounts (Note 2)	(22,433)	(23,778)
Materials and supplies (at average cost)	444,344	410,481
Fossil fuel (at average cost)	49,203	40,155
Income tax receivable (Note 4)	332	14,086
Assets from risk management activities (Note 15)	6,808	87,835
Assets held for sale (Note 20)	35,139	—
Deferred fuel and purchased power regulatory asset (Note 3)	463,195	460,561
Other regulatory assets (Note 3)	162,562	78,318
Other current assets	101,417	60,091
Total current assets	1,926,967	1,750,554
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 12 and 18)	1,201,246	1,073,410
Other special use funds (Notes 12 and 18)	362,781	347,231
Assets from risk management activities (Note 15)	—	44,394
Other assets	102,845	125,672
Total investments and other assets	1,666,872	1,590,707
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9)		
Plant in service and held for future use	24,211,167	22,452,146
Accumulated depreciation and amortization	(8,408,040)	(7,929,878)
Net	15,803,127	14,522,268
Construction work in progress	1,724,004	1,882,791
Palo Verde sale leaseback, net of accumulated depreciation of $264,624 and $260,754 (Note 17)	86,426	90,296
Intangible assets, net of accumulated amortization of $885,505 and $817,961	267,110	258,880
Nuclear fuel, net of accumulated amortization of $118,074 and $126,157	99,490	100,119
Total property, plant and equipment	17,980,157	16,854,354
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3, 4 and 7)	1,390,279	1,283,221
Operating lease right-of-use assets (Note 8)	1,309,975	801,688
Assets for pension and other postretirement benefits (Note 7)	323,438	396,599
Other	63,465	46,282
Total deferred debits	3,087,157	2,527,790
TOTAL ASSETS	$ 24,661,153	$ 22,723,405

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

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED BALANCE SHEETS

(dollars in thousands)

	December 31,	
	2023	2022
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 442,455	$ 430,425
Accrued taxes	166,833	164,440
Accrued interest	72,916	61,217
Common dividends payable	99,813	97,895
Short-term borrowings (Note 5)	609,500	340,720
Current maturities of long-term debt (Note 6)	875,000	50,685
Customer deposits	42,037	41,769
Liabilities from risk management activities (Note 15)	80,913	37,697
Liabilities for asset retirements (Note 11)	28,550	12,232
Operating lease liabilities (Note 8)	67,883	105,210
Regulatory liabilities (Note 3)	209,923	271,575
Other current liabilities	193,524	148,276
Total current liabilities	2,889,347	1,762,141
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 6)	7,540,622	7,741,286
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	2,416,480	2,384,421
Regulatory liabilities (Notes 1, 3, 4 and 7)	1,965,865	2,061,776
Liabilities for asset retirements (Note 11)	937,451	785,530
Liabilities for pension benefits (Note 7)	112,702	116,286
Liabilities from risk management activities (Note 15)	42,975	4,749
Customer advances	533,580	422,103
Coal mine reclamation	184,007	179,255
Deferred investment tax credit	257,743	180,677
Unrecognized tax benefits (Note 4)	33,861	38,658
Operating lease liabilities (Note 8)	1,210,189	639,247
Other	251,469	247,400
Total deferred credits and other	7,946,322	7,060,102
COMMITMENTS AND CONTINGENCIES (Note 10)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 113,537,689 and 113,247,189 issued at respective dates	2,752,676	2,724,740
Treasury stock at cost; 113,272 and 73,613 shares at respective dates	(8,185)	(5,005)
Total common stock	2,744,491	2,719,735
Retained earnings	3,466,317	3,360,347
Accumulated other comprehensive loss (Note 19)	(33,144)	(31,435)
Total shareholders' equity	6,177,664	6,048,647
Noncontrolling interests (Note 17)	107,198	111,229
Total equity	6,284,862	6,159,876
TOTAL LIABILITIES AND EQUITY	$ 24,661,153	$ 22,723,405

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,		
	2023	2022	2021
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 518,781	$ 500,826	$ 635,944
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on sale relating to BCE	(6,423)	—	—
Depreciation and amortization including nuclear fuel	854,136	817,814	719,141
Deferred fuel and purchased power	(549,877)	(291,992)	(256,871)
Deferred fuel and purchased power amortization	547,243	219,579	44,557
Allowance for equity funds used during construction	(53,118)	(45,263)	(41,737)
Deferred income taxes	(24,310)	43,202	117,471
Deferred investment tax credit	77,065	(5,893)	(4,802)
Change in derivative instruments fair value	(777)	777	—
Stock compensation	17,341	15,942	18,460
Changes in current assets and liabilities:			
Customer and other receivables	(61,983)	(63,869)	(72,559)
Accrued unbilled revenues	(2,789)	(30,784)	(1,783)
Materials, supplies and fossil fuel	(42,911)	(83,469)	(32,870)
Income tax receivable	13,754	(6,572)	(722)
Other current assets	(19,550)	76,089	(22,770)
Accounts payable	(75,623)	90,076	20,267
Accrued taxes	2,393	(4,205)	9,094
Other current liabilities	40,510	(1,856)	(51,736)
Change in long-term regulatory assets	53,112	12,432	(17,012)
Change in long-term regulatory liabilities	28,495	(332,470)	57,549
Change in other long-term assets	(195,598)	159,030	(345,470)
Change in operating lease assets	90,525	105,359	116,009
Change in other long-term liabilities	63,080	170,359	78,219
Change in operating lease liabilities	(65,779)	(103,671)	(108,365)
Net cash provided by operating activities	1,207,697	1,241,441	860,014
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,846,370)	(1,707,490)	(1,473,475)
Contributions in aid of construction	180,866	137,436	105,654
Proceeds from sale relating to BCE	23,400	—	—
Allowance for borrowed funds used during construction	(43,564)	(28,030)	(21,052)
Proceeds from nuclear decommissioning trust sales and other special use funds	1,679,722	1,207,713	1,720,966
Investment in nuclear decommissioning trust and other special use funds	(1,681,845)	(1,212,063)	(1,725,480)
Other	(6,458)	(15,612)	6,458
Net cash used for investing activities	(1,694,249)	(1,618,046)	(1,386,929)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	689,349	875,537	746,999
Repayment of long-term debt	(32,740)	(150,000)	—
Short-term borrowings and (repayments) — net	241,900	48,720	142,000
Short-term debt repayments under revolving credit facility	—	—	(19,000)

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	Accumulat Other Comprehens Income (Lo
	Shares	Amount	Shares	Amount		
Balance, December 31, 2020	112,760,051	$ 2,677,482	(72,006)	$ (6,289)	$ 3,025,106	$ (62,796)
Net income		—		—	618,720	—
Other comprehensive income		—		—	—	7,935
Dividends on common stock ($3.36 per share)		—		—	(379,108)	—
Issuance of common stock	254,477	25,261		—	—	—
Purchase of treasury stock (a)		—	(68,892)	(4,655)	—	—
Reissuance of treasury stock for stock-based compensation and other		—	53,290	4,543	—	—
Capital activities by noncontrolling interests		—		—	—	—
Other		—		—	1	—
Balance, December 31, 2021	113,014,528	2,702,743	(87,608)	(6,401)	3,264,719	(54,861)
Net income		—		—	483,602	—
Other comprehensive income		—		—	—	23,426
Dividends on common stock ($3.43 per share)		—		—	(387,975)	—
Issuance of common stock	232,661	21,996		—	—	—
Purchase of treasury stock (a)		—	(77,152)	(5,152)	—	—
Reissuance of treasury stock for stock-based compensation and other		—	91,147	6,548	—	—
Capital						

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

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, 2022. The effectiveness of our internal control over financial reporting as of December 31, 2023, 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 27, 2024

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, 2023 and 2022, 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, 2023, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, 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, 2023, 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 and compared to management's recorded regulatory assets and liabilities for completeness.
- We observed the ACC Open Meeting during which the Recommended Order and Opinion regarding the 2022 Retail Rate Case was amended and approved and read the approved 2022 Rate Case Recommended Order and Opinion as amended. We obtained and evaluated management's internally prepared analysis regarding impacts of the approved 2022 Rate Case Recommended Order and Opinion as amended to rates and recorded balances.
- 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 27, 2024

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,		
	2023	**2022**	**2021**
OPERATING REVENUES (Note 2)	$ 4,695,991	$ 4,324,385	$ 3,803,835
OPERATING EXPENSES			
Fuel and purchased power	1,792,657	1,629,343	1,152,551
Operations and maintenance	1,043,570	974,220	940,588
Depreciation and amortization	793,958	753,110	650,773
Taxes other than income taxes	223,962	220,277	234,569
Other expense	1,913	2,494	6,393
Total	3,856,060	3,579,444	2,984,874
OPERATING INCOME	839,931	744,941	818,961
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	53,118	45,263	41,737
Pension and other postretirement non-service credits, net (Note 7)	41,577	98,945	112,742
Other income (Note 16)	27,072	5,888	43,053
Other expense (Note 16)	(18,264)	(26,108)	(18,897)
Total	103,503	123,988	178,635
INTEREST EXPENSE			
Interest charges	323,719	262,815	243,592
Allowance for borrowed funds used during construction (Note 1)	(39,030)	(26,839)	(21,052)
Total	284,689	235,976	222,540
INCOME BEFORE INCOME TAXES	658,745	632,953	775,056
INCOME TAXES (Note 4)	94,184	90,800	125,553
NET INCOME	564,561	542,153	649,503
Less: Net income attributable to noncontrolling interests (Note 17)	17,224	17,224	17,224
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 547,337	$ 524,929	$ 632,279

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,		
	2023	2022	2021
NET INCOME	$ 564,561	$ 542,153	$ 649,503
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Pension and other postretirement benefits activity, net of tax benefit (expense) of $536, $(6,332), and $ (1,990) (Note 7)	(1,623)	19,284	6,038
Total other comprehensive income (loss)	(1,623)	19,284	6,038
COMPREHENSIVE INCOME	562,938	561,437	655,541
Less: Comprehensive income attributable to noncontrolling interests	17,224	17,224	17,224
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 545,714	$ 544,213	$ 638,317

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

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

	December 31,	
	2023	2022
ASSETS		
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9)		
Plant in service and held for future use	$ 24,207,706	$ 22,448,685
Accumulated depreciation and amortization	(8,404,721)	(7,926,575)
Net	15,802,985	14,522,110
Construction work in progress	1,724,004	1,829,004
Palo Verde sale leaseback, net of accumulated depreciation of $264,624 and $260,754 (Note 17)	86,426	90,296
Intangible assets, net of accumulated amortization of $884,371 and $816,827	266,955	258,725
Nuclear fuel, net of accumulated amortization of $118,074 and $126,157	99,490	100,119
Total property, plant and equipment	17,979,860	16,800,254
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 12 and 18)	1,201,246	1,073,410
Other special use funds (Notes 12 and 18)	362,781	347,231
Assets from risk management activities (Note 15)	—	44,394
Other assets	43,625	43,344
Total investments and other assets	1,607,652	1,508,379
CURRENT ASSETS		
Cash and cash equivalents	4,549	4,042
Customer and other receivables	510,296	448,880
Accrued unbilled revenues	167,553	164,764
Allowance for doubtful accounts (Note 2)	(22,433)	(23,778)
Materials and supplies (at average cost)	444,344	410,481
Fossil fuel (at average cost)	49,203	40,155
Income tax receivable (Note 4)	—	1,102
Assets from risk management activities (Note 15)	6,808	87,704
Deferred fuel and purchased power regulatory asset (Note 3)	463,195	460,561
Other regulatory assets (Note 3)	162,562	78,318
Other current assets	64,311	50,043
Total current assets	1,850,388	1,722,272
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3, 4, and 7)	1,390,279	1,283,221
Operating lease right-of-use assets (Note 8)	1,308,611	796,544
Assets for pension and other postretirement benefits (Note 7)	316,606	389,142
Other	63,059	44,040
Total deferred debits	3,078,555	2,512,947
TOTAL ASSETS	$ 24,516,455	$ 22,543,852

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

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

	December 31,	
	2023	2022
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	3,321,696	3,171,696
Retained earnings	3,759,299	3,607,464
Accumulated other comprehensive loss (Note 19)	(17,219)	(15,596)
Total shareholder equity	7,241,938	6,941,726
Noncontrolling interests (Note 17)	107,198	111,229
Total equity	7,349,136	7,052,955
Long-term debt less current maturities (Note 6)	7,041,891	6,793,529
Total capitalization	14,391,027	13,846,484
CURRENT LIABILITIES		
Short-term borrowings (Note 5)	532,850	325,000
Current maturities of long-term debt (Note 6)	250,000	—
Accounts payable	433,229	417,732
Accrued taxes	162,288	156,746
Accrued interest	72,548	60,518
Common dividends payable	99,800	97,900
Customer deposits	42,037	41,769
Liabilities from risk management activities (Note 15)	80,913	37,697
Liabilities for asset retirements (Note 11)	28,550	12,232
Operating lease liabilities (Note 8)	67,608	104,728
Regulatory liabilities (Note 3)	209,923	271,575
Other current liabilities	211,773	144,733
Total current liabilities	2,191,519	1,670,630
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	2,431,697	2,385,647
Regulatory liabilities (Notes 1, 3, 4 and 7)	1,965,865	2,061,776
Liabilities for asset retirements (Note 11)	937,451	785,530
Liabilities for pension benefits (Note 7)	106,215	108,068
Liabilities from risk management activities (Note 15)	42,975	3,840
Customer advances	533,580	422,103
Coal mine reclamation	184,007	179,255
Deferred investment tax credit	257,743	180,677
Unrecognized tax benefits (Note 4)	33,861	38,658
Operating lease liabilities (Note 8)	1,208,857	634,199
Other	231,658	226,985
Total deferred credits and other	7,933,909	7,026,738
COMMITMENTS AND CONTINGENCIES (Note 10)		
TOTAL LIABILITIES AND EQUITY	$ 24,516,455	$ 22,543,852

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,		
	2023	2022	2021
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 564,561	$ 542,153	$ 649,503
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	854,051	817,729	719,039
Deferred fuel and purchased power	(549,877)	(291,992)	(256,871)
Deferred fuel and purchased power amortization	547,243	219,579	44,557
Allowance for equity funds used during construction	(53,118)	(45,263)	(41,737)
Deferred income taxes	(10,314)	(6,817)	128,852
Deferred investment tax credit	77,065	(5,893)	(4,802)
Changes in current assets and liabilities:			
Customer and other receivables	(62,716)	(60,930)	(72,101)
Accrued unbilled revenues	(2,789)	(30,784)	(1,783)
Materials, supplies and fossil fuel	(42,911)	(83,469)	(32,870)
Income tax receivable	1,102	9,654	(10,756)
Other current assets	(20,243)	59,970	(25,637)
Accounts payable	(70,622)	79,492	23,510
Accrued taxes	5,542	4,734	3,042
Other current liabilities	62,212	1,190	(61,297)
Change in long-term regulatory assets	53,112	12,432	(17,012)
Change in long-term regulatory liabilities	28,495	(332,470)	57,549
Change in other long-term assets	(188,483)	170,587	(330,642)
Change in operating lease assets	90,234	105,058	115,850
Change in other long-term liabilities	58,574	168,503	87,376
Change in operating lease liabilities	(65,482)	(103,361)	(108,216)
Net cash provided by operating activities	1,275,636	1,230,102	865,554
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,825,585)	(1,655,051)	(1,471,795)
Contributions in aid of construction	180,866	137,436	105,654
Allowance for borrowed funds used during construction	(39,030)	(26,839)	(21,052)
Proceeds from nuclear decommissioning trust sales and other special use funds	1,679,722	1,207,713	1,720,966
Investment in nuclear decommissioning trust and other special use funds	(1,681,845)	(1,212,063)	(1,725,480)
Other	(1,397)	(727)	273
Net cash used for investing activities	(1,687,269)	(1,549,531)	(1,391,434)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	496,025	524,852	446,999
Short-term borrowings and (repayments) — net	180,970	46,300	278,700
Dividends paid on common stock	(393,600)	(385,800)	(376,500)
Equity infusion from Pinnacle West	150,000	150,000	150,000
Noncontrolling interests	(21,255)	(21,255)	(21,255)
Net cash provided by financing activities	412,140	314,097	477,944
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	507	(5,332)	(47,936)
CASH AND CASH EQUIVALENTS AT BEGINNING OF			

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)	N
	Shares	Amount				
Balance, December 31, 2020	71,264,947	$ 178,162	$ 2,871,696	$ 3,216,955	$ (40,918)	$
Equity infusion from Pinnacle West		—	150,000	—	—	
Net income		—	—	632,279	—	
Other comprehensive income		—	—	—	6,038	
Dividends on common stock		—	—	(379,000)	—	
Capital activities by noncontrolling interests		—	—	—	—	
Other		—	—	1	—	
Balance, December 31, 2021	71,264,947	178,162	3,021,696	3,470,235	(34,880)	
Equity infusion from Pinnacle West		—	150,000	—	—	
Net income		—	—	524,929	—	
Other comprehensive income		—	—	—	19,284	
Dividends on common stock		—	—	(387,700)	—	
Capital activities by noncontrolling interests		—	—	—	—	
Balance, December 31, 2022	71,264,947	178,162	3,171,696	3,607,464	(15,596)	
Equity infusion from Pinnacle West		—	150,000	—	—	
Net income		—	—	547,337	—	
Other comprehensive loss		—	—	—	(1,623)	
Dividends on common stock		—	—	(395,500)	—	
Capital activities by						

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: APS, El Dorado, BCE and PNW Power. 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. See Note 17 for additional information. We have determined that Pinnacle West is the primary beneficiary of a captive insurance protected cell VIE. As of December 31, 2023, the captive cell's activities are insignificant to our consolidated financial statements.

Our consolidated financial statements reflect all adjustments (consisting only of normal recurring adjustments, except as otherwise disclosed in the notes) that we believe are necessary for the fair presentation of our financial position, results of operations and cash flows for the periods presented.

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. To conform with the current year's disaggregated presentation of significant changes in assets and liabilities and the aggregation of less significant changes in assets and liabilities, we made certain reclassifications for the year ended December 31, 2022, within the operating activities section of our Consolidated Statements of Cash Flows.

Regulatory Accounting

APS is regulated by the ACC and the 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.

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.

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, 2023, and 2022 Consolidated Balance Sheets is composed of the following (dollars in thousands):

Property, Plant and Equipment:	2023	2022
Generation	$ 10,446,291	$ 9,563,145
Transmission	3,773,253	3,589,456
Distribution	8,448,293	7,951,867
General plant	1,543,330	1,347,678
Plant in service and held for future use	24,211,167	22,452,146
Accumulated depreciation and amortization	(8,408,040)	(7,929,878)
Net	15,803,127	14,522,268
Construction work in progress	1,724,004	1,882,791
Palo Verde sale leaseback, net of accumulated depreciation	86,426	90,296
Intangible assets, net of accumulated amortization	267,110	258,880
Nuclear fuel, net of accumulated amortization	99,490	100,119
Total property, plant and equipment	$ 17,980,157	$ 16,854,354

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, 2023, 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 $669 million in 2023, $632 million in 2022, and $575 million in 2021. For the years 2021 through 2023, the depreciation rates ranged from a low of 1.37% to a high of 12.15%. The weighted-average depreciation rate was 2.98% in 2023, 3.03% in 2022, and 2.87% in 2021.

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 radiated 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 6.29% for 2023, 5.75% for 2022, and 6.75% for 2021. 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.

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 2023. 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.

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,		
	2023	2022	2021
Cash paid during the period for:			
Income taxes, net of refunds	$ 8,788	$ 46,227	$ 229
Interest, net of amounts capitalized	310,996	245,271	227,584
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 206,269	$ 114,999	$ 167,733
Dividends declared but not paid	99,813	97,895	95,988
BCE Sale non-cash consideration (Note 20)	28,262	—	—

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	Year ended December 31,		
	2023	2022	2021
Cash paid during the period for:			
Income taxes, net of refunds	$ 21,734	$ 95,985	$ 19,783
Interest, net of amounts capitalized	267,261	227,159	217,749
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 206,269	$ 116,533	$ 167,657
Dividends declared but not paid	99,800	97,900	96,000

Intangible Assets

We have no goodwill recorded and have separately disclosed other intangible assets, primarily APS's software, on Pinnacle West's Consolidated Balance Sheets. The intangible assets are amortized over their finite useful lives. Amortization expense was $90 million in 2023, $84 million in 2022, and $80 million in 2021. Estimated amortization expense on existing intangible assets over the next five years is $90 million in 2024, $75 million in 2025, $49 million in 2026, $23 million in 2027, and $11 million in 2028. At December 31, 2023, 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, coal reclamation escrow accounts and active union employee medical account, 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 electricity service to Native Load customers) and related activities and includes electricity generation, transmission, and distribution. All other segment activities are insignificant.

Preferred Stock

At December 31, 2023, 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,		
	2023	2022	2021
Retail Electric Service			
Residential	$ 2,289,196	$ 2,046,111	$ 1,913,324
Non-Residential	2,048,416	1,767,616	1,586,940
Wholesale Energy Sales	208,985	383,126	187,640
Transmission Services for Others	138,631	116,628	99,285
Other Sources	10,763	10,904	16,646
Total Operating Revenues	$ 4,695,991	$ 4,324,385	$ 3,803,835

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 years ended December 31, 2023, 2022 and 2021 were $4,651 million, $4,302 million, and $3,760 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 years ended December 31, 2023, 2022 and 2021, our revenues that do not qualify as revenue from contracts with customers were $45 million, $22 million and $44 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.

Contract Assets and Liabilities from Contracts with Customers

There were no material contract assets, contract liabilities, or deferred contract costs recorded on the Consolidated Balance Sheets as of December 31, 2023 and December 31, 2022.

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,		
	2023	2022	2021
Allowance for doubtful accounts, balance at beginning of period	$ 23,778	$ 25,354	$ 19,782
Bad debt expense	23,399	17,006	22,251
Actual write-offs	(24,744)	(18,582)	(16,679)
Allowance for doubtful accounts, balance at end of period	$ 22,433	$ 23,778	$ 25,354

3. Regulatory Matters

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 the date rates become effective ("Day 1") of a net $460 million. This Day 1 net impact represents a total base revenue deficiency of $772 million offset by proposed adjustor transfers of cost recovery to annual retail rates and adjustor mechanism modifications. The average annual customer bill impact of APS's request on Day 1 is an increase of 13.6%.

The principal provisions of APS's application were:

- a test year comprised of twelve months ended June 30, 2022, adjusted as described below;
- an original cost rate base of $10.5 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	48.07 %	3.85 %
Common stock equity	51.93 %	10.25 %
Weighted-average cost of capital		7.17 %

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- a rate of $0.038321 per kWh for the portion of APS's retail base rates attributable to fuel and purchased power costs ("Base Fuel Rate");
- modification of its adjustment mechanisms including:

- eliminate the Environmental Improvement Surcharge ("EIS") and collect costs through base rates,
- eliminate the Lost Fixed Cost Recovery ("LFCR") mechanism and collect costs through base rates and the Demand Side Management Adjustment Charge ("DSMAC"),

    - maintain as inactive the Tax Expense Adjustor Mechanism (“TEAM”),
    - maintain the Transmission Cost Adjustment (“TCA”) mechanism,
    - modify the performance incentive in the DSMAC, and
    - modify the Renewable Energy Adjustment Charge (“REAC”) to include recovery of capital carrying costs of APS owned renewable and storage resources;
- changes to its limited-income program, including a second tier to provide an additional discount for customers with greater need; and
- twelve months of post-Test Year plant investments to reflect used and useful projects that will be placed into service prior to July 1, 2023.

On June 5, 2023, and June 15, 2023, the ACC Staff, the Residential Utility Consumer Office (“RUCO”) and other intervenors filed their initial written testimony with the ACC. The ACC Staff recommends, among other things, (i) a $251 million revenue increase or, as an alternative, a $312 million revenue increase, (ii) a 9.6% return on equity, (iii) a 0.0% fair value increment or, as an alternative, a 0.75% fair value increment, and (iv) a continuation of a 12-month post-test year plant. RUCO recommends, among other things, (i) an $84.9 million revenue increase, (ii) an 8.2% return on equity or, as an alternative, an 8.7% return on equity if the ACC imputes a hypothetical capital structure with a 46% equity layer, (iii) a fair value increment of 0.0%, and (iv) a reduction of post-test year plant to six months.

On July 12, 2023, APS filed rebuttal testimony addressing the ACC Staff and intervenors’ direct testimonies. The principal provisions of APS’s rebuttal testimony are:

- reducing the revenue requirement increase to $383.1 million, which reduced the average annual customer bill impact to an increase of 11.3%;
- maintaining a return on equity request of 10.25%;
- reducing the increment of fair value rate base return to 0.5% from 1.0%;
- maintaining a post-test year plant request of 12 months, plus the Four Corners Effluent Limitation Guidelines (“ELG”) project;
- withdrawing the Payment Fee Removal Proposal (net reduction) which was originally requested in APS’s initial application;
- maintaining the LFCR mechanism and DSMAC as separate adjustors;
- increasing the Power Supply Adjustment (“PSA”) annual rate change limit from $0.004/kWh to $0.006/kWh;
- proposing a new System Reliability Benefit (“SRB”) recovery mechanism;
- maintaining the REAC in its current state;
- maintaining adjustor base transfers and elimination of EIS; and
- maintaining the request to recover Coal Community Transition (“CCT”) funding.

On July 26, 2023, the ACC Staff, RUCO and other intervenors filed their surrebuttal testimony with the ACC. The ACC Staff adjusted their initial recommendations to, among other things, (i) a $281.9 million revenue increase, (ii) a 9.68% return on equity, (iii) a 0.5% fair value increment, (iv) a continuation of a 12-month post-test year plant that includes the Four Corners ELG project, and (v) support of an increase to the annual PSA increase limit to $0.006/kWh. RUCO maintained their direct position and also recommended further review of the PSA in a second phase of the 2022 Rate Case.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On August 4, 2023, APS filed rejoinder testimony addressing the ACC Staff and intervenors' surrebuttal testimonies. APS's rejoinder testimony included final post-Test Year Plant values, reducing the revenue requirement increase to $377.7 million from $383.1 million, which reduced the average annual customer bill impact to an increase of 11.2%. All other major provisions from APS's rebuttal testimony were maintained in its rejoinder testimony.

On November 6, 2023, and November 21, 2023, APS and stakeholders filed briefs in the 2022 Rate Case. APS's briefs included the reduction of the total revenue requirement increase to $376.2 million and a resulting average annual customer bill impact increase of 11.1%. All other major provisions from APS's rejoinder testimony were maintained in its briefs. ACC Staff's briefs included a proposed total revenue requirement increase from $281.9 million to $282.7 million and also included their support of APS's SRB mechanism, contingent on increased stakeholder outreach.

On January 25, 2024, an Administrative Law Judge issued a Recommended Opinion and Order 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 ELG project, (vi) the approval of APS's SRB proposal with certain procedural and other modifications, (vii) no additional 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 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 ("RFP"), and (viii) recovery of all DSM costs through the 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 is expected to issue the final order for the 2022 Rate Case in March 2024 with the new rates to become effective for all service rendered on or after March 8, 2024.

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 Recommended Opinion and Order in the 2019 Rate Case (the "2019 Rate Case ROO") and issued corrections on September 10 and September 20, 2021.

The 2019 Rate Case ROO recommended, among other things, (i) a $111 million decrease in annual revenue requirements, (ii) a return on equity of 9.16%, (iii) a 0.30% return on the increment of fair value rate base greater than original cost, with total fair value rate of return further adjusted to include a 0.03% reduction to return on equity resulting in an effective fair value rate of return of 4.95%, (iv) the nonrecovery of the deferral and rate base effects of the operating costs and construction of the Four Corners Power Plant ("Four Corners") selective catalytic reduction ("SCR") project (see "Four Corners SCR Cost Recovery" below for additional information), (v) the recovery of the deferral and rate base effects of the operating costs and construction of the Ocotillo modernization project, which includes a reduction in the return on the deferral, (vi) a 15% disallowance of annual amortization of the Navajo Generating Station (the "Navajo Plant") regulatory asset recovery related to the closure of the Navajo Plant (see "Navajo Plant" below), (vii) the denial of the request to defer, until APS's next general rate case, the increase or decrease in its Arizona property taxes attributable to tax rate changes, and (viii) a collaborative process to review and recommend revisions to APS's adjustment mechanisms within 12 months after the date of the decision. The 2019 Rate Case ROO also recommended that the CCT plan related to the closure or future closure of coal-fired generation facilities include the following components: (i) $50 million that will be paid over 10 years to the Navajo Nation, (ii) $5 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant ("Cholla"), and (iii) $1.675 million that will be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant. These amounts would be recoverable from APS's customers through the Arizona Renewable Energy Standard and Tariff ("RES") adjustment mechanism. APS filed exceptions on September 13, 2021, regarding the disallowance of the SCR cost deferrals and plant investments that was recommended in the 2019 Rate Case ROO, among other issues.

On October 6, 2021, and October 27, 2021, the ACC voted on various amendments to the 2019 Rate Case ROO that would result in, among other things, (i) a return on equity of 8.70%, which includes a 20-basis point penalty, (ii) the recovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project, with the exception of $215.5 million (see "Four Corners SCR Cost Recovery" below), (iii) that the CCT plan include 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. These payments and expenditures are attributable to the future closures of Four Corners and Cholla, along with the prior closure of the Navajo Plant and all ordered payments and expenditures would be recoverable through rates, 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. On November 2, 2021, the ACC approved the 2019 Rate Case ROO, as amended.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Consistent with the 2019 Rate Case decision, APS implemented the new rates effective as of December 1, 2021. In addition, the ACC ordered extensive compliance and reporting obligations. APS completed the implementation of the new on-peak hours for residential customers before the September 1, 2022, deadline.

Additionally, consistent with the 2019 Rate Case decision, as of February 2024, APS completed the following payments that will be recoverable through rates related to the CCT: (i) $6.66 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 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 has also authorized $1.25 million to be recovered through rates for electrification of homes and businesses on both the Navajo Nation and Hopi reservation. 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 $1.25 million 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.

On November 24, 2021, APS filed an application for rehearing of the 2019 Rate Case with the ACC and the application was deemed denied on December 15, 2021, as the ACC did not act upon it. On December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals and a Petition for Special Action with the Arizona Supreme Court, requesting review of the disallowance of $215.5 million of Four Corners SCR plant investments and deferrals (see "Four Corners SCR Cost Recovery" below for additional information) and the 20-basis-point penalty reduction to the return on equity, among other things. On February 8, 2022, the Arizona Supreme Court declined to accept jurisdiction on APS's Petition for Special Action. The Arizona Court of Appeals heard oral arguments on November 30, 2022. 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-point 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. The ACC requested an extension of the 30-day deadline to appeal the matter to the Arizona Supreme Court, and the Arizona Supreme Court granted the extension of the deadline to May 8, 2023. The ACC filed an appeal on May 8, 2023, and on May 15, 2023, requested a suspension of the case to allow for settlement discussions between the parties, which was approved by the Court.

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 point 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 of 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. On July 18, 2023, the Sierra Club filed an application for rehearing of the ACC's decision. However, the ACC did not act upon the application within 20 days, and it was therefore denied by operation of law. Subsequently, the Sierra Club did not file a notice of appeal to the Arizona Court of Appeals, and the time for an appeal has expired.

Matter of Impact of the Closures of Fossil-Based Generation Plan on Impacted Communities

On September 28, 2022, ACC Staff filed their staff report in the Matter of Impact of the Closures of Fossil-Based Generation Plan on Impacted Communities. APS and other interested parties filed comments on the report. On October 21, 2022, ACC Staff filed a revised report and proposed order. The revised report and proposed order recommended that funds for CCT shall not be collected from rate payers. On December 8, 2022, the ACC voted against ACC Staff's proposed order, and on April 17, 2023, the ACC closed the docket. On February 22, 2024, the ACC voted to not approve any further CCT funding.

Information Technology ACC Investigation

On December 16, 2021, the ACC opened an investigation into various matters related to APS's Information Technology department, including information about technology projects, costs, vendor management leadership and decision making. APS is cooperating with the investigation. APS cannot predict the outcome of this matter.

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 from utilities and interested parties on ways to reduce regulatory lag, including alternative ratemaking structures such as future test years and hybrid test years. APS filed comments on June 1, 2023. 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 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 2015, the ACC revised the RES rules to allow the ACC to consider all available information, including the number of rooftop solar arrays in a utility's service territory, to determine compliance with the RES.

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 Recommended Order and Opinion, 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 RFP 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 September 23, 2022, APS filed a community solar proposal in compliance with the ACC order that was informed by a stakeholder working group. APS proposed a small, pilot-scale program size of up to 140 MW that would be selected through a competitive RFP. The ACC has not yet ruled on the proposal. However, on November 10, 2022, the ACC approved a bifurcated community solar process, directing ACC Staff to develop a statewide policy through additional stakeholder involvement and establishing a separate evidentiary hearing to define other policy components. On March 23, 2023, the ACC approved a policy statement that included information on how statewide community solar and storage programs should be structured, their location, and inclusion in RFPs. The remainder of the community solar program policy components were deferred to the ACC’s Hearing Division so that a formal evidentiary hearing could be held to consider issues of substance related to community solar. APS cannot predict the outcomes of these future activities.

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.

Demand Side Management Adjustor Charge. The ACC Electric Energy Efficiency Standards require APS to submit a DSM 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 grow and 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. The ACC has not yet ruled on the 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 $0.004 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 2023 and 2022 (dollars in thousands):

	Twelve Months Ended December 31,	
	2023	2022
Beginning balance	$ 460,561	$ 388,148
Deferred fuel and purchased power costs — current period	549,877	291,992
Amounts charged to customers	(547,243)	(219,579)
Ending balance	$ 463,195	$ 460,561

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 contains 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 finds that APS's fuel processing accounting practices, dispatching procedures, and procedures for hedging activity are reasonable and appropriate. The report includes 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. To address the growing under-collected PSA balance, APS also requested that one of three different options be adopted, including a temporary or permanent increase of the annual cap to $0.006 per kWh. 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. APS is also required to notify the ACC when the PSA balancing account approaches $0.5 million. In its 2022 Rate Case, APS proposed a permanent increase in the annual PSA adjustor rate cap, which would increase the amount the rate can change in any given year from the currently effective $0.004 per kWh to $0.006 per kWh. On February 22, 2024, the ACC voted to approve this request.

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 this time.

In accordance with the PSA Plan of Administration, APS is required to seek ACC approval to recover costs related to third-party energy storage systems through its PSA adjustment mechanism. In

2023, nine energy storage PPAs and their respective costs have been approved for recovery through the PSA. In 2022, one energy storage PPA and its costs was approved for recovery through the PSA. In 2021, four energy storage PPAs and their respective costs were approved for recovery through the PSA. However, one energy storage PPA that was approved in 2021 was later terminated by APS due to project delays.

Environmental Improvement Surcharge ("EIS"). The EIS permits 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. A filing is made on or before February 1 each year for qualified environmental improvements since the prior rate case test year, and the new charge becomes effective April 1 unless suspended by the ACC. The EIS includes an overall cap of $0.0005 per kWh (approximately $13 million to $15 million per year). APS's February 1, 2023, 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. On February 1, 2024, APS filed an application requesting an increase in the charge to $15.3 million, or $11.3 million over the prior-period charge. The 2022 Rate Case ROO has recommended eliminating the EIS. On February 22, 2024, the ACC approved the elimination of the EIS as recommended in the 2022 Rate Case ROO. With the elimination of the EIS, the surcharge will no longer be in effect.

Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters. In July 2008, FERC approved a modification to APS's Open Access Transmission Tariff to allow APS to move from fixed rates to a formula rate-setting methodology in order to more accurately reflect and recover the costs that APS incurs in providing transmission services. A large portion of the rate represents charges for transmission services to serve APS's retail customers ("Retail Transmission Charges"). In order to recover the Retail Transmission Charges, APS was previously required to file an application with, and obtain approval from, the ACC to reflect changes in Retail Transmission Charges through the TCA. Under the terms of the settlement agreement entered into in 2012 regarding APS's rate case ("2012 Settlement Agreement"), however, an adjustment to rates to recover the Retail Transmission Charges will be made annually each June 1 and will go into effect automatically unless suspended by the ACC.

The 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.

On March 17, 2020, APS submitted a filing to make modifications to its annual transmission formula to provide additional transparency for excess and deficient accumulated deferred income taxes resulting from the Tax Cuts and Job Act (the "Tax Act"), as well as for future local, state, and federal statutory tax rate changes. APS amended its March 17, 2020, filing on April 28, 2020, September 29, 2021, and October 27, 2021. In January 2022, FERC approved APS's modifications to its annual transmission formula.

Effective June 1, 2021, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $4 million for the 12-month period beginning June 1, 2021, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates decreased by approximately $3.2 million and retail customer rates would have increased by approximately $7.2 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 $28.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2021.

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.

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 fixed costs recoverable by the LFCR mechanism were 2.50 cents for both lost residential and non-residential kWh as set forth in the settlement agreement in the 2017 rate case (the "2017 Settlement Agreement"). The fixed costs recoverable by the LFCR mechanism are currently 2.56 cents for lost residential kWh and 2.68 cents for lost non-residential kWh as set forth in the 2019 Rate Case decision. 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, 2021, APS filed its 2021 annual LFCR adjustment, requesting that effective May 1, 2021, the annual LFCR recovery amount be increased to $38.5 million (an $11.8 million increase from previous levels). On April 13, 2021, the ACC voted not to approve the requested $11.8 million increase to the annual LFCR adjustment; thus, the previously approved rates continued to remain intact and the $11.8 million increase was reflected in APS's 2022 filing in accordance with the compliance requirements.

As a result of the 2019 Rate Case decision, APS's annual LFCR adjustor rate will be dependent on an annual earnings test filing, which will compare APS's previous year's rate of return with the related authorized rate of return. If the actual rate of return is higher than the authorized rate of return, the LFCR rate for the subsequent year is set at zero. APS determined that the changes to the LFCR mechanism, as a result of the 2019 Rate Case decision effective on December 1, 2021, did not materially impact its results of operations and financial statements for the year ended December 31, 2021. However, as a result of certain changes made to the LFCR mechanism in the 2019 Rate Case decision, the mechanism no longer qualified for alternative revenue program accounting treatment, which impacts the future timing of related revenue recognition.

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 the $11.8 million balance from the 2021 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. Upon conclusion of discovery, ACC Staff will provide a Memorandum and Proposed Order that the parties will have an opportunity to respond to. The ACC has not yet ruled on this application.

Tax Expense Adjustor Mechanism. As part of the 2017 Settlement Agreement, the parties agreed to a rate adjustment mechanism to 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, the TEAM rates were reset to zero beginning December 31, 2021. The TEAM was retained in the 2022 Rate Case to address potential changes in tax law that may be enacted prior to a decision in a subsequent APS rate case.

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 of 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 current CRS will be recalculated on the effective date of the 2022 Rate Case to remove the effects of the prospective recovery related to the allowable return on equity difference. The portion of the CRS representing the recovery of the $59.6 million of lost revenue between December of 2021 and June 20, 2023, $9.4 million of which has been collected as of December 31, 2023, will cease upon full collection of the lost revenue. Finally, recovery of ongoing costs related to the SCR investments will continue until the Company's next rate case in which they can be incorporated therein. On February 22, 2024, the ACC approved the 2022 Rate Case ROO, as amended. The CRS tariff is currently being recalculated to reflect the final decision in that 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 distributed generation ("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 will be updated annually (between general retail rate cases) but will not be decreased by more than 10% per year. The ACC is no longer pursuing development of a forecasted avoided cost methodology as an option for utilities in place of the RCP. Commercial customers, grandfathered residential solar customers, and residential customers with DG systems other than solar facilities continue to qualify for net metering.

In addition, the ACC made the following determinations in the Value and Cost of Distributed Generation docket:

- RCP customers who have interconnected a DG system or submitted an application for interconnection for DG systems will be grandfathered for a period of 20 years from the date the customer's interconnection application was accepted by the utility (for APS residential customers, as of September 1, 2017, based on APS's 2017 Rate Case Decision);
- customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and
- once an initial export price is set for utilities, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future general retail rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies.

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 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 will conduct discovery to investigate the issues related to this matter. A status conference will be held on March 20, 2024, to determine if ACC Staff is prepared to present a recommendation on this matter at that time. The amounts the Company pays customers for solar exports under its RCP rate rider could be affected by this docket. 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 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. 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 timeframe. 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 has until May 31, 2024, to respond to the stakeholders' comments. APS cannot predict the outcome of this matter. 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 is currently authorized to receive up to $150 million annually in equity infusions from Pinnacle West without seeking ACC approval. APS sought approval under Arizona Administrative Code provision R14-2-803 to receive from Pinnacle West in 2024 up to $500 million in additional equity infusions above the currently authorized limit of $150 million annually. On January 9, 2024, the ACC approved the increased equity infusion limit for 2024.

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. During calendar year 2020, APS entered into two 18-year PPAs with qualified facilities, each for 80 MW solar facilities. In March 2021, the ACC approved these agreements. On July 19, 2023, the agreements for these two PPAs were terminated due to project delays.

Residential Electric Utility Customer Service Disconnections

On June 13, 2019, APS voluntarily suspended electric disconnections for residential customers who had not paid their bills. On June 20, 2019, the ACC voted to enact emergency rule amendments to prevent residential electric utility customer service disconnections during the period June 1 through October 15 ("Summer Disconnection Moratorium"). During the Summer Disconnection Moratorium, APS could not charge late fees and interest on amounts that were past due from customers. Customer deposits must also be used to pay delinquent amounts before disconnection can occur. In accordance with the emergency rules, APS began putting delinquent customers on a mandatory four-month payment plan beginning on October 16, 2019.

In June 2019, the ACC began a formal regular rulemaking process to allow stakeholder input and time for consideration of permanent rule changes. The ACC further ordered that each regulated utility serving retail customers in Arizona update its service conditions by incorporating the emergency rule amendments, restore power to any customers who were disconnected during the month of June 2019 and credit any fees that were charged for a reconnection. The ACC Staff and ACC proposed draft amendments to the customer service disconnections rules. On April 14, 2021, the ACC voted to send to the formal rulemaking process a draft rules package governing customer disconnections that allows utilities to choose between a temperature threshold (above 95 degrees and below 32 degrees) or calendar method (June 1 – October 15) for disconnection moratoriums. On November 2, 2021, the ACC approved the final rules, and on November 23, 2021, the rules were submitted to the Arizona Office of the Attorney General for final review and approval. The new rules became effective on April 18, 2022.

In accordance with the ACC service disconnection rules, APS now uses the calendar-based method to suspend the disconnection of customers for nonpayment from June 1 through October 15 each year ("Annual Disconnection Moratorium"). Customers with past due balances of $75 or greater as of 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. 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. APS cannot predict what impact, if any, this change will have on APS.

On August 4, 2021, Green Mountain Energy filed an application seeking a certificate of convenience and necessity to allow it to provide competitive electric generation service in Arizona. Green Mountain Energy has requested that the ACC grant it the ability to provide competitive service in APS's and Tucson Electric Power Company's certificated service territories and proposes to deliver a 100% renewable energy product to residential and general service customers in those service territories. APS opposes Green Mountain Energy's application. On November 3, 2021, the ACC submitted questions to the Arizona Attorney General requesting legal opinions related to a number of issues surrounding retail electric competition and the ACC's ability to issue competitive certificates of convenience and necessity. On November 26, 2021, the Administrative Law Judge issued a procedural order indicating it would not be appropriate to set a schedule until the Attorney General has provided insights on the applicable law. As the ACC's questions pertained to the retail competition law subsequently repealed in April 2022, the Attorney General has not responded to the ACC's request and the questions are now moot. No action has been taken by the ACC regarding this application since that time. However, on May 17, 2023, the Retail Energy Supply Association filed a motion with the ACC requesting it to re-open the generic docket to re-examine the ACC's electric competition rules. No action has been taken by the ACC regarding this motion. APS cannot predict the outcome of these matters.

On October 28, 2021, an ACC Commissioner docketed a letter directing ACC Staff and interested stakeholders to design a 200 to 300 MW pilot program that would allow residential and small commercial customers of APS to elect a competitive electricity supplier. The letter also states that similar programs should be designed for other Arizona regulated electric utilities. APS cannot predict the outcome of these future activities.

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 Recommended Opinion and Order 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 United States Environmental Protection Agency ("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. Pursuant to the 2017 Settlement Agreement described above, APS will be allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs, $32.7 million as of December 31, 2023, 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.

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, $43.0 million as of December 31, 2023, 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, $10.9 million as of December 31, 2023. The disallowed recovery of 15% of the annual amortization does not have a material impact on APS financial statements.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Regulatory Assets and Liabilities

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

		December 31,	
	Amortization Through	2023	2022
Pension	(a)	$ 696,476	$ 637,656
Deferred fuel and purchased power (b) (c)	2024	463,195	460,561
Income taxes — AFUDC equity	2053	189,058	179,631
Ocotillo deferral	2031	128,636	138,143
Deferred fuel and purchased power — mark-to-market (Note 16)	2026	120,214	—
SCR deferral (e)	2038	89,477	97,624
Retired power plant costs	2033	83,536	98,692
Lease incentives (Note 8)	(g)	46,615	—
Income taxes — investment tax credit basis adjustment	2056	34,230	23,977
Deferred compensation	2036	33,972	33,660
Deferred property taxes	2027	32,488	41,057
Palo Verde VIEs (Note 17)	2046	20,772	20,933
Power supply adjustor-interest	2024	19,416	1,541
Active union medical trust	(f)	12,747	18,226
Navajo coal reclamation	2026	10,883	13,862
Mead-Phoenix transmission line — contributions in aid of construction	2050	8,716	9,048
Loss on reacquired debt	2038	7,965	9,468
Four Corners cost deferral	2024	7,922	15,999
Tax expense adjustor mechanism (b)	2031	5,190	5,845
Lost fixed cost recovery (b)	2023	—	9,547
Other	Various	4,528	6,630
Total regulatory assets (d)		$ 2,016,036	$ 1,822,100
Less: current regulatory assets		$ 625,757	$ 538,879
Total non-current regulatory assets		$ 1,390,279	$ 1,283,221

(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 approved 2022 Rate Case ROO, as amended, 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.”

Table of Contents

(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. See Note 8.

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

		December 31,	
	Amortization Through	2023	2022
Excess deferred income taxes - ACC — Tax Cuts and Jobs Act (a)	2046	$ 930,344	$ 971,545
Excess deferred income taxes - FERC — Tax Cuts and Jobs Act (a)	2058	214,667	221,877
Asset retirement obligations	2057	392,383	354,002
Other postretirement benefits	(d)	226,726	270,604
Removal costs	(c)	94,368	106,889
Income taxes — deferred investment tax credit	2056	68,521	48,035
Income taxes — change in rates	2051	60,667	64,806
Four Corners coal reclamation	2038	55,917	52,592
Renewable energy standard (b)	2024	43,251	35,720
Spent nuclear fuel	2027	33,154	39,217
Sundance maintenance	2031	19,989	16,893
Demand side management (b)	2023	14,374	8,461
Property tax deferral (e)	2024	10,850	15,521
Tax expense adjustor mechanism (b)	2031	4,835	4,835
FERC transmission true up (b)	2025	1,869	22,895
Deferred fuel and purchased power — mark-to-market (Note 15)	2026	—	96,367
Other	Various	3,873	3,092
Total regulatory liabilities		$ 2,175,788	$ 2,333,351
Less: current regulatory liabilities		$ 209,923	$ 271,575
Total non-current regulatory liabilities		$ 1,965,865	$ 2,061,776

(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) In accordance with regulatory accounting, APS accrues removal costs for its regulated assets, even if there is no legal obligation for removal.
(d) See Note 7.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

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.

Net income associated with the 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 the 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		
	2023	2022	2021	2023	2022	202
Total unrecognized tax benefits, January 1	$ 43,097	$ 45,086	$ 45,655	$ 43,097	$ 45,086	$ 45,6
Additions for tax positions of the current year	1,473	1,399	3,305	1,473	1,399	3,3
Additions for tax positions of prior years	419	2,069	1,449	419	2,069	1,4
Reductions for tax positions of prior years for:						
Changes in judgment	661	(3,495)	(2,659)	661	(3,495)	(2,6
Settlements with taxing authorities	—	—	—	—	—	-
Lapses of applicable statute of limitations	(1,376)	(1,962)	(2,664)	(1,376)	(1,962)	(2,6
Total unrecognized tax benefits, December 31	$ 44,274	$ 43,097	$ 45,086	$ 44,274	$ 43,097	$ 45,0

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	
	2023	2022	2021	2023	2022
Tax positions, that if recognized, would decrease our effective tax rate	$ 28,762	$ 28,246	$ 26,300	$ 28,762	$ 28,246

As of the balance sheet date, the tax year ended December 31, 2020, 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 2019.

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		
	2023	2022	2021	2023	2022	2021
Unrecognized tax benefit interest expense/(benefit) recognized	$ 452	$ (139)	$ (535)	$ 452	$ (139)	$ (535)

Following are the total amount 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		
	2023	2022	2021	2023	2022	2021
Unrecognized tax benefit interest accrued	$ 1,633	$ 1,181	$ 1,320	$ 1,633	$ 1,181	$ 1,320

Additionally, as of December 31, 2023, we have recognized less than $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,		
	2023	2022	2021	2023	2022	2021
Current:						
Federal	$ 21,272	$ 35,617	$ (5,041)	$ 26,405	$ 103,349	$ 1,51
State	2,854	1,950	2,458	1,027	161	(1
Total current	24,126	37,567	(2,583)	27,432	103,510	1,50
Deferred:						
Federal	37,273	23,693	95,327	44,922	(31,860)	101,17
State	15,513	13,567	17,342	21,830	19,150	22,87
Total deferred	52,786	37,260	112,669	66,752	(12,710)	124,05
Income tax expense/(benefit)	$ 76,912	$ 74,827	$ 110,086	$ 94,184	$ 90,800	$ 125,55

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,	
	2023	2022	2021	2023	2022
Federal income tax expense at statutory rate	$ 125,095	$ 120,887	$ 156,666	$ 138,337	$ 132,920
Increases (reductions) in tax expense resulting from:					
State income tax net of federal income tax benefit	18,024	17,740	22,656	19,832	19,000
State income tax credits net of federal income tax benefit	(3,513)	(5,482)	(7,015)	(1,775)	(3,744)
Net operating loss carryback tax benefit	—	—	(5,915)	—	—
Excess deferred income taxes — Tax Cuts and Jobs Act	(36,558)	(36,241)	(36,558)	(36,558)	(36,241)
Allowance for equity funds used during construction (Note 1)	(5,964)	(4,629)	(4,180)	(5,964)	(4,629)
Palo Verde VIE noncontrolling interest (Note 17)	(3,617)	(3,617)	(3,617)	(3,617)	(3,617)
Investment tax credit amortization	(9,495)	(5,608)	(7,620)	(9,495)	(5,608)
Federal production tax credit	(8,441)	(3,146)	(3,064)	(5,460)	—
Other federal income tax credits	(3,453)	(7,721)	(3,912)	(2,803)	(7,721)
Other	4,834	2,644	2,645	1,687	440
Income tax expense/(benefit)	$ 76,912	$ 74,827	$ 110,086	$ 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,	
	2023	2022	2023	2022
DEFERRED TAX ASSETS				
Risk management activities	$ 31,411	$ 8,826	$ 31,411	$ 8,826
Regulatory liabilities:				
Excess deferred income taxes — Tax Cuts and Jobs Act	283,161	295,014	283,161	295,014
Asset retirement obligation and removal costs	113,312	107,104	113,312	107,104
Unamortized investment tax credits	68,521	48,035	68,521	48,035
Other postretirement benefits	56,070	66,893	56,070	66,893
Other	39,857	62,915	39,857	62,915
Operating lease liabilities	316,067	184,030	315,670	182,663
Pension liabilities	33,294	33,674	29,918	30,436
Coal reclamation liabilities	45,505	44,312	45,505	44,312
Renewable energy incentives	17,261	19,948	17,261	19,948
Credit and loss carryforwards	43,940	37,647	3,031	13,654
Other	77,865	72,605	77,865	72,605
Total deferred tax assets	1,126,264	981,003	1,081,582	952,405
DEFERRED TAX LIABILITIES				
Plant-related	(2,572,495)	(2,518,164)	(2,572,495)	(2,518,164)
Risk management activities	(1,682)	(32,648)	(1,682)	(32,648)
Pension and other postretirement assets	(78,853)	(96,845)	(78,297)	(96,196)
Other special use funds	(56,550)	(57,572)	(56,550)	(57,572)
Operating lease right-of-use assets	(316,067)	(184,030)	(315,670)	(182,663)
Regulatory assets:				
Allowance for equity funds used during construction	(46,754)	(44,405)	(46,754)	(44,405)
Deferred fuel and purchased power	(149,078)	(114,232)	(149,078)	(114,232)
Pension benefits	(172,239)	(157,629)	(172,239)	(157,629)
Retired power plant costs	(20,659)	(24,397)	(20,659)	(24,397)
Other	(92,260)	(103,023)	(92,260)	(103,023)
Other	(36,107)	(32,479)	(7,595)	(7,123)
Total deferred tax liabilities	(3,542,744)	(3,365,424)	(3,513,279)	(3,338,052)

As of December 31, 2023, Pinnacle West consolidated deferred tax assets for credit and loss carryforwards relate to federal and state credit carryforwards, net of federal benefit, of $56 million, which first begin to expire in 2025. Pinnacle West consolidated credit and loss carryforwards amount above has been reduced by $12 million of unrecognized tax benefits.

As of December 31, 2023, APS consolidated deferred tax assets for credit and loss carryforwards relate to federal and state credit carryforwards, net of federal benefit, of $15 million, which first begin to expire in 2028. APS consolidated credit and loss carryforwards amount above has been reduced by $12 million of unrecognized tax benefits.

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 facilities and the amounts available and outstanding (dollars in thousands):

	December 31, 2023			December 31, 2022		
	Pinnacle West	APS	Total	Pinnacle West	APS	Total
Commitments under Credit Facilities	$ 200,000	$ 1,250,000	$ 1,450,000	$ 200,000	$ 1,000,000	$ 1,200,000
Outstanding short-term borrowings	(76,650)	(532,850)	(609,500)	(15,720)	(325,000)	(340,720)
Amount of Credit Facilities Available	$ 123,350	$ 717,150	$ 840,500	$ 184,280	$ 675,000	$ 859,280
Weighted-Average Commitment Fees	0.170%	0.120%		0.175%	0.125%	

Pinnacle West

On April 10, 2023, Pinnacle West replaced its $200 million revolving credit facility that would have matured on May 28, 2026, with a new $200 million revolving credit facility that matures on April 10, 2028. 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, 2023, Pinnacle West had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under the credit facility, and $77 million of outstanding commercial paper borrowings. The weighted-average interest rate for the outstanding borrowings on December 31, 2023, was 5.47%.

APS

On April 10, 2023, APS replaced its two $500 million revolving credit facilities that would have matured on May 28, 2026, with a new $1.25 billion revolving credit facility that matures on April 10, 2028. APS has the option to increase the amount of the facility 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, 2023, APS had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under the credit facility, and

$533 million of outstanding commercial paper borrowings. The weighted-average interest rate for the outstanding borrowings on December 31, 2023, was 5.46%.

On December 12, 2023, APS entered into an agreement with a new 364-day $350 million term loan facility that matures on December 10, 2024. Borrowings under the facility bear interest at SOFR plus 1.0% per annum. On February 9, 2024, APS drew the full amount of $350 million.

See "Financial Assurances" in Note 10 for a discussion of other outstanding letters of credit.

Debt Provisions

On December 15, 2022, the ACC issued a financing order that, among other things, 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). See Note 6 for additional long-term debt provisions.

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, 2023	December 31, 2022
APS				
Pollution control bonds:				
Variable	2029	(b)	$ 163,975	$ 163,975
Total pollution control bonds			163,975	163,975
Senior unsecured notes	2024-2050	2.20%-6.88%	7,180,000	6,680,000
Unamortized discount			(14,197)	(14,548)
Unamortized premium			11,162	12,368
Unamortized debt issuance cost			(49,049)	(48,266)
Total APS long-term debt			7,291,891	6,793,529
Less current maturities			250,000	—
Total APS long-term debt less current maturities			7,041,891	6,793,529
BCE				
Los Alamitos equity bridge loan	(d)	(d)	—	27,575
Los Alamitos construction facility	(d)	(d)	—	23,110
Unamortized debt issuance cost			—	(135)
Total BCE long-term debt			—	50,550
Less current maturities			—	50,685
Total BCE long-term debt less current maturities			—	(135)
Pinnacle West				
Senior unsecured notes	2025	1.30%	500,000	500,000
Term loans	2024	(c)	625,000	450,000
Unamortized discount			(15)	(25)
Unamortized debt issuance cost			(1,254)	(2,083)
Total Pinnacle West long-term debt			1,123,731	947,892
Less current maturities			625,000	—
Total Pinnacle West long-term debt less current maturities			498,731	947,892
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$ 7,540,622	$ 7,741,286

(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 4.11% at December 31, 2023, and 3.96% at December 31, 2022.
(c) The weighted-average interest rate was 6.20% at December 31, 2023, and 5.10% at December 31, 2022. See additional details below.

(d) On August 4, 2023, concurrent with the BCE Sale, the construction facility was transferred to Ameresco and the equity bridge loan was paid in full by Pinnacle West. See Note 20 and discussion 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
2024	$ 875,000	$ 250,000
2025	800,000	300,000
2026	250,000	250,000
2027	300,000	300,000
2028	—	—
Thereafter	6,243,975	6,243,975
Total	$ 8,468,975	$ 7,343,975

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, 2023		As of December 31, 2022	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 1,123,731	$ 1,095,935	$ 947,892	$ 905,525
APS	7,291,891	6,459,718	6,793,529	5,629,491
BCE	—	—	50,550	50,685
Total	$ 8,415,622	$ 7,555,653	$ 7,791,971	$ 6,585,701

Credit Facilities and Debt Issuances

Pinnacle West

On December 16, 2022, Pinnacle West entered into a $175 million term loan facility that matures 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.

APS

APS is currently authorized to receive up to $150 million annually in equity infusions from Pinnacle West without seeking ACC approval. On October 27, 2023, APS sought approval from the ACC to receive from Pinnacle West in 2024 up to an additional $500 million in equity infusions above the authorized limit of $150 million, and on January 9, 2024, the ACC approved the increased equity infusion limit for 2024.

On January 6, 2023, Pinnacle West contributed $150 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness.

On June 30, 2023, APS issued $500 million of 5.55% unsecured senior notes that mature August 1, 2033. The net proceeds from the sale were used to repay short-term indebtedness consisting of commercial paper and for general corporate purposes.

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, 2023, 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, 2023, the ratio was approximately 60% for Pinnacle West and 52% 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 December 15, 2022, the ACC issued a financing order approving APS's application filed on April 6, 2022, requesting to increase the long-term debt limit from $7.5 billion to $8.0 billion and to exclude financing lease PPAs from the definition of long-term indebtedness for purposes of the ACC financing orders. 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		
	2023	2022	2021	2023	2022	
Service cost-benefits earned during the period	$ 39,461	$ 55,473	$ 61,236	$ 8,567	$ 16,470	$
Non-service costs (credits):						
Interest cost on benefit obligation	153,561	107,492	98,566	22,509	17,491	
Expected return on plan assets	(182,938)	(185,775)	(202,628)	(43,486)	(46,042)	
Amortization of:						
Prior service credit (a)	—	—	—	(37,789)	(37,789)	
Net actuarial (gain)/loss	38,420	17,515	15,948	(9,614)	(12,835)	
Net periodic benefit cost/(benefit)	$ 48,504	$ (5,295)	$ (26,878)	$ (59,813)	$ (62,705)	$
Portion of cost/(benefit) charged to expense	$ 27,029	$ (16,431)	$ (32,743)	$ (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	
	2023	2022	2023	2022
Change in Benefit Obligation				
Benefit obligation at January 1	$ 2,809,529	$ 3,716,824	$ 409,461	$ 591,841
Service cost	39,461	55,473	8,567	16,470
Interest cost	153,561	107,492	22,509	17,491
Benefit payments	(210,737)	(212,565)	(30,784)	(30,913)
Actuarial (gain) loss	116,249	(857,695)	20,681	(185,428)
Benefit obligation at December 31	2,908,063	2,809,529	430,434	409,461
Change in Plan Assets				
Fair value of plan assets at January 1	2,829,485	3,812,041	652,287	872,435
Actual return/(loss) on plan assets	199,098	(787,874)	67,317	(193,807)
Benefit payments	(193,034)	(194,682)	(23,110)	(26,341)
Fair value of plan assets at December 31	2,835,549	2,829,485	696,494	652,287
Funded/(Underfunded) Status at December 31	$ (72,514)	$ 19,956	$ 266,060	$ 242,826

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	As of December 31,	
	2023	2022
Accumulated benefit obligation	$ 123,701	$ 126,759
Fair value of plan assets	—	—

The Pinnacle West Capital Corporation Retirement Plan is more than 100% funded on an accumulated benefit obligation basis at December 31, 2023, and December 31, 2022, therefore, the only pension plan with an accumulated benefit obligation in excess of plan assets in 2023 and 2022 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,	
	2023	2022
Projected benefit obligation	$ 129,891	$ 133,818
Fair value of plan assets	—	—

The Pinnacle West Capital Corporation Retirement Plan is more than 100% funded on a projected benefit obligation basis at December 31, 2023, and December 31, 2022, therefore the only pension plan with a projected benefit obligation in excess of plan assets in 2023 and 2022 is a 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	
	2023	2022	2023	2022
Noncurrent asset	$ 57,378	$ 153,773	$ 266,060	$ 242,826
Current liability	(17,190)	(17,531)	—	—
Noncurrent liability	(112,702)	(116,286)	—	—
Net amount recognized (funded status)	$ (72,514)	$ 19,956	$ 266,060	$ 242,826

The following table shows the details related to accumulated other comprehensive loss (gain) as of December 31, 2023, and 2022 (dollars in thousands):

	Pension Plans		Other Benefits Plans	
	2023	2022	2023	2022
Net actuarial loss (gain)	$ 743,003	$ 681,335	$ (188,630)	$ (195,095)
Prior service credit	—	—	(39,054)	(76,843)
APS's portion recorded as a regulatory (asset) liability	(696,476)	(637,656)	226,726	270,604
Income tax expense (benefit)	(11,506)	(10,797)	691	784
Accumulated other comprehensive loss (gain)	$ 35,021	$ 32,882	$ (267)	$ (550)

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,		
	2023	2022	2023	2022	2021
Discount rate – pension plans	5.21 %	5.56 %	5.56 %	2.92 %	2.53 %
Discount rate – other benefits plans	5.23 %	5.58 %	5.58 %	2.98 %	2.63 %
Rate of compensation increase	4.52 %	4.57 %	4.57 %	4.00 %	4.00 %
Expected long-term return on plan assets - pension plans	N/A	N/A	6.70 %	5.00 %	5.30 %
Expected long-term return on plan assets - other benefit plans	N/A	N/A	6.80 %	5.35 %	4.90 %
Initial healthcare cost trend rate (pre-65 participants)	6.25 %	6.50 %	6.50 %	6.00 %	6.50 %
Ultimate healthcare cost trend rate (pre-65 participants)	4.75 %	4.75 %	4.75 %	4.75 %	4.75 %
Number of years to ultimate trend rate (pre-65 participants)	5	6	5	3	4
Initial and ultimate healthcare cost trend rate (post-65 participants)	2.00 %	2.00 %	2.00 %	2.00 %	2.00 %
Interest crediting rate – cash balance pension plans	4.54 %	4.50 %	4.50 %	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 2024, we are assuming a 6.90% long-term rate of return for pension assets and 7.00% (before tax) for other benefit assets, which we believe is reasonable given our asset allocation in relation to historical and expected performance.

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

Plan Assets

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

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

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

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, 2023, are as follows:

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

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

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

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

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

As of December 31, 2023, 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, 2023:

	Actual Allocation
Long-term fixed income assets	62 %
Return-seeking assets	38 %
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, 2023, 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, 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
Short-term investments and 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
Short-term investments and 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 international common stock equities.
(e) This category 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, 2022, by asset category, are as follows (dollars in thousands):

	Level 1	Level 2	Other (a)	Total
Pension Plan:				
Cash and cash equivalents	$ 1,252	$ —	$ —	$ 1,252
Fixed income securities:				
Corporate	—	1,374,810	—	1,374,810
U.S. Treasury	635,245	—	—	635,245
Other (b)	—	131,999	—	131,999
Common stock equities (c)	155,231	—	—	155,231
Mutual funds (d)	101,557	—	—	101,557
Common and collective trusts:				
Equities	—	—	181,912	181,912
Real estate	—	—	174,228	174,228
Partnerships	—	—	13,359	13,359
Short-term investments and other (e)	—	—	59,892	59,892
Total	$ 893,285	$ 1,506,809	$ 429,391	$ 2,829,485
Other Benefits:				
Cash and cash equivalents	$ 204	$ —	$ —	$ 204
Fixed income securities:				
Corporate	—	166,879	—	166,879
U.S. Treasury	221,936	—	—	221,936
Other (b)	—	7,321	—	7,321
Common stock equities (c)	127,493	—	—	127,493
Mutual funds (d)	18,824	—	—	18,824
Common and collective trusts:				
Equities	—	—	73,956	73,956
Real estate	—	—	23,541	23,541
Short-term investments and other (e)	3,274	—	8,859	12,133
Total	$ 371,731	$ 174,200	$ 106,356	$ 652,287

(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.
(c) This category primarily consists of U.S. common stock equities.
(d) These funds invest in U.S. and international common stock equities.
(e) This category includes plan receivables and payables.

Contributions

Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. In 2023 and 2022, we did not make any contributions to our pension plan. In 2021, we made contributions to our pension plan totaling $100 million. The minimum required contributions for the pension plan are zero for the next three years and we do not expect to make any voluntary contributions in 2024, 2025, or 2026. With regard to contributions to our other postretirement benefit plan, we did not make a contribution in 2023 or 2022 and do not expect to make any contributions in 2024, 2025 or 2026.

The Company was reimbursed $23 million in 2023, $26 million in 2022, and $24 million in 2021 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
2024	$ 244,772	$ 31,024
2025	226,748	30,446
2026	229,322	30,396
2027	226,906	30,024
2028	229,397	29,741
Years 2029-2033	1,136,944	149,312

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 2023, 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 $12 million for 2023, $12 million for 2022, and $12 million for 2021.

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 2024 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.

In January 2023, APS modified two existing purchase power operating lease agreements. Among other changes, the modifications extend the expiration dates of these contracts from October 2027 to October 2032 for one of the leases, and from September 2026 to October 2034 for the other lease. These lease agreements previously commenced in 2020 and 2021.

APS has executed various energy storage purchased power lease agreements that allow APS the right to charge and discharge energy storage facilities. The first of these energy storage leases commenced in September 2023, and is classified as an operating lease. This agreement provides APS the use of the energy storage facility through May 2043. APS pays a fixed monthly capacity price for rights to use the leased asset. APS does not operate or maintain the energy storage facility, and has no purchase options or residual value guarantees relating to the lease asset. For this class of energy storage lease assets, APS has elected to separate the lease and non-lease components.

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

	Year Ended December 31,		
	2023	2022	2021
Operating Lease Cost - Purchased Power & Energy Storage Lease Contracts	$ 126,655	$ 104,001	$ 105,762
Operating Lease Cost - Land, Property, and Other Equipment	19,235	18,061	18,498
Total Operating Lease Cost	145,890	122,062	124,260
Variable Lease Cost (a)	135,007	122,040	118,969
Short-term Lease Cost	21,530	9,928	3,872
Total Lease Cost	$ 302,427	$ 254,030	$ 247,101

(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 sheet.

The following table provides information related to the maturity of our operating lease liabilities (dollars in thousands):

	December 31, 2023		
Year	**Purchased Power & Energy Storage Lease Contracts**	**Land, Property & Equipment Leases**	**Total**
2024	$ 108,201	$ 14,750	$ 122,951
2025	124,968	12,148	137,116
2026	138,692	9,826	148,518
2027	164,613	7,731	172,344
2028	168,410	5,401	173,811
Thereafter	835,813	64,090	899,903
Total lease commitments	1,540,697	113,946	1,654,643
Less imputed interest	334,693	41,878	376,571
Total lease liabilities	$ 1,206,004	$ 72,068	$ 1,278,072

We recognize lease assets and liabilities upon lease commencement. At December 31, 2023, 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 $7.1 billion over the terms of the agreements. These arrangements primarily relate to energy storage assets. The lease commencement dates for these arrangements have experienced delays. APS continues to work with the lessors to determine revised commencement dates. We expect lease commencement dates ranging from April 2024 through June 2025, with lease terms expiring through May 2045. As a result of these delays and other events, APS has received cash proceeds from the 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,						
	2023			2022		2021	
Cash paid for amounts included in the measurement of lease liabilities — operating cash flows:	$	123,472		$	118,463	$	116,661
Right-of-use operating lease assets obtained in exchange for operating lease liabilities		602,301	(a)		16,990		500,582

	December 31, 2023		December 31, 2022	
Weighted average remaining lease term	10 years		7 years	
Weighted average discount rate (b)	4.53	%	2.21	%

(a) Primarily relates to the two purchased power operating lease agreements that were modified in January 2023.

(b) 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, 2023 (dollars in thousands):

	Percent Owned		Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating facilities:					
Palo Verde Units 1 and 3	29.1 %		$ 1,990,237	$ 1,087,614	$ 21,442
Palo Verde Unit 2 (a)	16.8 %		681,483	387,485	12,700
Palo Verde Common	28.0 %	(b)	857,807	356,962	65,911
Palo Verde Sale Leaseback		(a)	351,050	264,624	—
Four Corners Generating Station	63.0 %		1,748,436	659,780	29,586
Cholla Common Facilities (c)	50.5 %		250,994	167,357	7,487
Transmission facilities:					
ANPP 500kV System	33.4 %	(b)	136,145	58,252	4,801
Navajo Southern System	25.2 %	(b)	87,185	36,743	550
Palo Verde — Yuma 500kV System	25.3 %	(b)	24,057	7,912	432
Four Corners Switchyards	57.5 %	(b)	84,279	21,918	161
Phoenix — Mead System	17.1 %	(b)	39,772	20,679	257
Palo Verde — Rudd 500kV System	50.0 %		95,736	32,665	731
Morgan — Pinnacle Peak System	63.2 %	(b)	117,080	26,990	229
Round Valley System	50.0 %		548	205	—
Palo Verde — Morgan System	87.5 %	(b)	268,629	40,962	8,053
Hassayampa — North Gila System	80.0 %		151,684	24,618	—

(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.

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 submitted nine claims pursuant to the terms of the August 18, 2014 settlement agreement, for nine separate time periods during July 1, 2011 through October 31, 2022. The DOE has approved and paid $138.2 million for these claims (APS's share is $40.2 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, 2023, APS filed its tenth claim pursuant to the terms of the August 18, 2014, settlement agreement in the amount of $18.46 million (APS's share is $5.4 million). In February 2024, the DOE approved $18.39 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 $22.4 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 $62.6 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.

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 2024 and 2045 that include required purchase provisions. APS estimates the contract requirements to be approximately $1,034 million in 2024; $1,190 million in 2025; $1,310 million in 2026; $1,284 million in 2027; $1,292 million in 2028; and $14.7 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.

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

	Year Ended December 31,				
	2024	2025	2026	2027	2028
Coal take-or-pay commitments (a)	$ 208,694	$ 229,111	$ 221,122	$ 200,256	$ 205,237

(a) Total take-or-pay commitments are approximately $1.7 billion. The total net present value of these commitments is approximately $1.4 billion.

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,		
	2023	2022	2021
Total purchases	$ 255,219	$ 305,502	$ 219,958

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 $29 million in 2024; $27 million in 2025; $24 million in 2026; $20 million in 2027; $17 million in 2028; and $52 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 $184 million at December 31, 2023, and $179 million at December 31, 2022. Under our current coal supply agreements, APS expects to make payments for the final mine reclamation as follows: $19 million in 2024; $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. APS cannot predict the EPA's timing with respect to this matter. 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 ultimate remediation requirements are not yet finalized by EPA, 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, which is on appeal to the U.S. Court of Appeals for the Ninth Circuit based on a U.S. District Court order dismissing cost recovery claims of approximately $20.7 million by a service provider for RID. 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 our financial position, results of operations or cash flows.

In addition, as part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, the ADEQ sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. Since that time, ADEQ has taken no action based on the information provided by APS.

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 the Company 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 SCR Cost Recovery

As part of APS's 2019 Rate Case, APS included recovery of the deferral and rate base effects of the Four Corners SCR project. 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 Note 3 for additional information regarding the Four Corners SCR cost recovery and the 2019 Rate Case.

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 coal combustion residuals ("CCRs"). These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates but cannot predict whether it will obtain such recovery. The following proposed and final rules could involve material compliance costs to APS.

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of 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 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. Although ADEQ has taken steps to develop a CCR permitting program, and new state legislation has been adopted providing ADEQ with appropriate permitting authority for CCR under the state solid waste management program, it is not clear when that program will be put into effect. 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 sometime in 2024.

- On May 18, 2023, EPA published a proposal that expands the scope of federal CCR regulations to address the impacts from historical CCR disposal activities that would have ceased prior to 2015. EPA proposes to define a new class of CCR management units ("CCRMUs") that 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. EPA expects to finalize this proposal by spring of 2024.

We cannot at this time 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.

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 by April 11, 2021, at the latest (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 will also solicit input from the public and host 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. See Note 11. 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, APS cannot predict any ultimate impacts to APS; however, at this time APS does not believe that any potential changes to the cost estimate 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.

In the latest set of proposed rules, released on May 23, 2023, EPA contemplates 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, the most recent proposal is limited to measures that can be installed at individual power plants to limit planet-warming 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") or varying levels of hydrogen gas ("H2") co-firing. As for existing natural gas-fired combustion turbines, EPA is imposing similar control requirements at large, high utilization generating units, but is otherwise not proceeding at this time with further regulation. As such, under EPA's proposal, this means that both new and existing peaking gas-fired combustion turbines (i.e., those with a 20% or less annual capacity factor) are effectively unregulated under the proposed regulations.

For coal-fired power plants, instead of imposing regulations based on capacity and utilization, EPA has developed subcategories based on planned retirement dates. This means that facilities retiring between 2030 and before 2040 must meet increasingly stringent emission limits up to natural-gas co-firing starting in 2030. However, for those facilities with no planned retirement date prior to 2040, EPA is requiring those plants to be retrofitted with CCS controls by 2030.

EPA expects to take final action on this proposal by spring or summer of 2024. At this time, APS cannot predict the outcome of this rulemaking or when EPA will take final action. In addition, APS is continuing to evaluate this proposal and its potential impact on APS's operations. Depending on the eventual outcome, the costs associated with APS's operation of its current and future thermal power plants could materially increase, which could affect our financial condition, results of operations, or cash flows.

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

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 of 2021, and APS does not expect the outcome to have a material impact on our financial condition, results of operations, or cash flows.

Four Corners — 4CA Matter

On July 6, 2016, 4CA purchased El Paso Electric Company's 7% interest in Four Corners. NTEC purchased this 7% interest on July 3, 2018, from 4CA. NTEC purchased the 7% interest at 4CA's book value, approximately $70 million, and paid 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note, which was paid in full as of June 30, 2022.

In connection with the sale, Pinnacle West guaranteed certain obligations that NTEC will have to the other owners of Four Corners, such as NTEC's 7% share of capital expenditures and operating and maintenance expenses. Pinnacle West's guarantee is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement.

PNW Power Wind Projects

In October 2023, the Tenaska wind farm investments were reorganized such that they are no longer held by BCE, rather they are now held under the new Pinnacle West subsidiary, PNW Power. See Notes 1 and 20 for more information.

Tenaska Clear Creek Wind, LLC, the developer, owner, and operator of the Clear Creek wind farm, has disputed the proposed cost allocation of system upgrades related to connecting the Clear Creek wind farm to the transmission system. Tenaska Clear Creek Wind, LLC, filed complaints with FERC on this matter on May 21, 2021, and May 25, 2022, both of which FERC has denied. In April 2023, Tenaska Clear Creek Wind, LLC filed Petitions for Review of the relevant FERC orders with the U.S. Court of Appeals for the D.C. Circuit, which are still pending.

Due to disputed system upgrades and curtailment issues, the Clear Creek wind farm has experienced a significant reduction in power generation that has had a material adverse impact on the project's ability to generate cash flow for investors. During the fourth quarter of 2022, due to these ongoing disputes, cost allocation uncertainties, and no probable favorable resolution, the equity method investment was fully impaired. Prior to the impairment, the investment had a carrying value of $17.1 million, which was written-down to reflect the investment's estimated fair value of zero as of December 31, 2022. Pinnacle West's Consolidated Statement of Income for the year ended December 31, 2022, includes an after-tax loss of $12.8 million relating to this impairment.

BCE Kūpono Solar

BCE and Ameresco jointly owned a special purpose entity that is sponsoring the Kūpono Solar project. This project is a 42 MW solar and battery storage facility in O'ahu, Hawaii that will supply clean renewable energy and capacity under a 20-year power purchase agreement with Hawaiian Electric Company, Inc. The Kūpono Solar project is expected to be completed in 2024. On April 18, 2023, the Kūpono Solar special purpose entity entered into a $140 million non-recourse construction financing agreement. The construction financing will convert into a sale leaseback agreement upon commercial operation of the project. As of December 31, 2023, the construction financing agreement required $40 million of sponsor equity, which has been funded by the project's equity participants and which is subject to adjustment under the construction financing agreement. In connection with the financing, Pinnacle West has issued performance guarantees relating to the project. Investments in the Kūpono Solar project are included in the BCE Sale which closed on January 12, 2024. Subsequent to the BCE Sale, Pinnacle West continues to maintain the performance guarantees relating to the Kūpono Solar project 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, 2023, standby letters of credit totaled approximately $27 million and will expire in 2024. As of December 31, 2023, surety bonds expiring through 2025 totaled approximately $20 million. 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, 2023. In connection with the sale of 4CA's 7% interest to NTEC, Pinnacle West is guaranteeing certain obligations that NTEC will have to the other owners of Four Corners. See "Four Corners — 4CA Matter" above for information related to this guarantee. 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, 2023, there is approximately $31 million of remaining guarantees relating to these PTC Guarantees that are expected to terminate by 2030.

Pinnacle West has issued various performance guarantees in connection with BCE's Kūpono Solar project investment financing, and is exposed to losses relating to these guarantees upon the occurrence of certain events that we do not consider to be reasonably likely to occur. Subsequent to the BCE Sale, Pinnacle West continues to maintain these performance guarantees. See Note 20. As of December 31, 2023, these performance guarantees had no significant impact on our Consolidated Balance Sheets or Consolidated Statements of Income. The details of the guarantees are as follows:

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

- Upon the BCE Sale closing, which occurred on January 12, 2024, Pinnacle West committed to certain performance guarantees tied to the Kūpono project achieving certain construction and operation milestones. These performance guarantees will expire when the Kūpono project achieves commercial operation, which is expected in 2024.
- When the Kūpono financing coverts to a sale leaseback agreement, which is expected to occur upon commercial operation of the project, 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.
- Ameresco is obligated to reimburse Pinnacle West for any payments made by Pinnacle West under such guarantees.

11. Asset Retirement Obligations

In 2023, the Company revised its cost estimates for existing Asset Retirement Obligations ("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. See Note 10.
- Four Corners coal-fired power plant, which resulted in a decrease of approximately $7 million.
- Navajo coal-fired 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.

In 2022, APS did not revise any cost estimates related to existing AROs, and no new AROs were necessary.

See additional details in Notes 3 and 10.

The following table shows the change in our AROs (dollars in thousands):

	2023	2022
Asset retirement obligations at the beginning of year	$ 797,762	$ 767,382
Changes attributable to:		
Accretion expense	44,269	41,240
Settlements	(14,039)	(10,860)
Estimated cash flow revisions	135,323	—
Newly incurred obligation	2,686	—
Asset retirement obligations at the end of year	$ 966,001	$ 797,762

In accordance with regulatory accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal. See detail of regulatory liabilities in Note 3.

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.

Instruments valued using NAV as a practical expedient are included in our fair value disclosures; however, in accordance with GAAP are not classified within the fair value hierarchy levels.

Recurring Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, and investments held in the nuclear decommissioning trusts and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefit plans. See Note 7 for fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

Cash equivalents represent certain investments in money market funds that are valued using quoted prices in active markets.

Risk Management Activities — Energy Derivative Instruments

Exchange traded commodity contracts are valued using unadjusted quoted prices. For non-exchange traded commodity contracts, we calculate fair value based on the average of the bid and offer price, discounted to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed out or hedged. The credit valuation adjustment represents estimated credit losses on our net exposure to counterparties, taking into account netting agreements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. We maintain credit policies that management believes minimize overall credit risk.

Certain non-exchange traded commodity contracts are valued based on unobservable inputs due to the long-term nature of contracts, characteristics of the product, or the unique location of the transactions. Long-dated energy transactions may consist of observable valuations for the near-term portion and unobservable valuations for the long-term portions of the transaction. We rely primarily on broker quotes to value these instruments. When our valuations utilize broker quotes, we perform various control procedures to ensure the quote has been developed consistent with fair value accounting guidance. These controls include assessing the quote for reasonableness by comparison against other broker quotes, reviewing historical price relationships, and assessing market activity. When broker quotes are not available, the primary valuation technique used to calculate the fair value is the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at more illiquid delivery points.

When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3.

Risk Management Activities — Interest Rate Derivatives

Our interest rate derivative instruments related to a BCE interest rate swap, which was valued using financial models that utilize observable inputs for similar instruments and was classified as Level 2. The interest rate swap is no longer held as of December 31, 2023. See Note 20.

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 and the active union employee medical account. See Note 18 for additional discussion about our investment accounts.

We value investments in fixed income and equity securities using information provided by our trustees and escrow agent. Our trustees and escrow agent use pricing services that utilize the valuation methodologies described below to determine fair market value. We have internal control procedures designed to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustees' and escrow agent's internal operating controls and valuation processes.

Fixed Income Securities

Fixed income securities issued by the U.S. Treasury are valued using quoted active market prices and are typically classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies, including mortgage-backed instruments, are valued using quoted inactive market prices, quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield curves and spreads relative to such yield curves. These fixed income instruments are classified as Level 2. Whenever possible, multiple market quotes are obtained which enables a cross-check validation. A primary price source is identified based on asset type, class, or issue of securities.

Fixed income securities may also include short-term investments in certificates of deposit, variable rate notes, time deposit accounts, U.S. Treasury and Agency obligations, U.S. Treasury repurchase agreements, commercial paper, and other short-term instruments. These instruments are valued using active market prices or utilizing observable inputs described above.

Equity Securities

The nuclear decommissioning trusts' equity security investments are held indirectly through commingled funds. The commingled funds are valued using the funds' NAV as a practical expedient. The funds' NAV is primarily derived from the quoted active market prices of the underlying equity securities held by the funds. We may transact in these commingled funds on a 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, 2023, of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

Balance at December 31, 2023	Level 1	Level 2	Level 3	Other		
ASSETS						
Cash equivalents	$ 10	$ —	$ —	$ —		$
Risk management activities — derivative instruments:						
Commodity contracts	—	1,881	6,616	(1,689)	(a)	
Nuclear decommissioning trust:						
Equity securities	11,064	—	—	(767)	(b)	
U.S. commingled equity funds	—	—	—	409,616	(c)	
U.S. Treasury debt	319,734	—	—	—		
Corporate debt	—	188,317	—	—		
Mortgage-backed securities	—	208,306	—	—		
Municipal bonds	—	59,323	—	—		
Other fixed income	—	5,653	—	—		
Subtotal nuclear decommissioning trust	330,798	461,599	—	408,849		
Other special use funds:						
Equity securities	40,991	—	—	2,196	(b)	
U.S. Treasury debt	319,594	—	—	—		
Municipal bonds	—	—	—	—		
Subtotal other special use funds	360,585	—	—	2,196		
Total assets	$ 691,393	$ 463,480	$ 6,616	$ 409,356		$
LIABILITIES						
Risk management activities — derivative instruments:						
Commodity						

(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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value at December 31, 2022, of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

Balance at December 31, 2022	Level 1	Level 2	Level 3	Other		
ASSETS						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 127,129	$ 26,132	$ (21,163)	(a)	$
Interest rate swaps	—	131	—	—		
Subtotal risk management activities - derivative instruments	—	127,260	26,132	(21,163)		
Nuclear decommissioning trust:						
Equity securities	14,658	—	—	3,827	(b)	
U.S. commingled equity funds	—	—	—	472,582	(c)	
U.S. Treasury debt	211,923	—	—	—		
Corporate debt	—	149,226	—	—		
Mortgage-backed securities	—	147,938	—	—		
Municipal bonds	—	64,881	—	—		
Other fixed income	—	8,375	—	—		
Subtotal nuclear decommissioning trust	226,581	370,420	—	476,409		
Other special use funds:						
Equity securities	66,974	—	—	963	(b)	
U.S. Treasury debt	275,267	—	—	—		
Municipal bonds	—	4,027	—	—		
Subtotal other special use funds	342,241	4,027	—	963		
Total assets	$ 568,822	$ 501,707	$ 26,132	$ 456,209		$
LIABILITIES						
Risk						

(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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

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, 2023, and December 31, 2022:

	December 31, 2023 Fair Value (thousands)		Valuation	Significant	
Commodity Contracts	**Assets**	**Liabilities**	**Technique**	**Unobservable Input**	**Range**
Electricity:					
Forward Contracts (a)	$ 6,587	$ 658	Discounted cash flows	Electricity forward price (per MWh)	$37.79 -
Natural Gas:					
Forward Contracts (a)	29	1,037	Discounted cash flows	Natural gas forward price (per MMBtu)	$0.00 -
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.

Commodity Contracts	December 31, 2022 Fair Value (thousands) Assets	Liabilities	Valuation Technique	Significant Unobservable Input	
Electricity:					
Forward Contracts (a)	$ 26,132	$ 1,759	Discounted cash flows	Electricity forward price (per MWh)	$ 37.79
Natural Gas:					
Forward Contracts (a)	—	29,261	Discounted cash flows	Natural gas forward price (per MMBtu)	$(11.81)
Total	$ 26,132	$ 31,020			

(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	**2023**	**2022**
Net derivative balance at beginning of period	$ (4,888)	$ (2,738)
Total net gains (losses) realized/unrealized:		
Deferred as a regulatory asset or liability	(70,214)	(374)
Settlements	69,706	(1,123)
Transfers into Level 3 from Level 2	(1,289)	(846)
Transfers from Level 3 into Level 2	11,606	193
Net derivative balance at end of period	$ 4,921	$ (4,888)
Net unrealized gains 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. Earnings Per Share

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

	2023	**2022**	**2021**
Net income attributable to common shareholders	$ 501,557	$ 483,602	$ 618,720
Weighted average common shares outstanding — basic	113,442	113,196	112,910
Net effect of dilutive securities:			
Contingently issuable performance shares and restricted stock units	362	220	282
Weighted average common shares outstanding — diluted	113,804	113,416	113,192
Earnings per weighted-average common share outstanding			
Net income attributable to common shareholders — basic	$ 4.42	$ 4.27	$ 5.48
Net income attributable to common shareholders — diluted	$ 4.41	$ 4.26	$ 5.47

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 ("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

Table of Contents

authorizes up to 4.3 million common shares to be available for grant. As of December 31, 2023, 3.5 million common shares were available for issuance under the 2021 Plan. During 2023, 2022 and 2021, the Company granted awards in the form of restricted stock units, stock units, stock grants, and performance shares. Awards granted from 2012 to May 2021 were issued under the 2012 Long-Term Incentive Plan ("2012 Plan"), and awards granted from 2007 to 2011 were issued under the 2007 Long-Term Incentive Plan ("2007 Plan"). No new awards may be granted under the 2012 or 2007 Plans.

Stock-Based Compensation Expense and Activity

Compensation cost included in net income for stock-based compensation plans was $17 million in 2023, $16 million in 2022, and $18 million in 2021. The compensation cost capitalized is immaterial for all years. Income tax benefits related to stock-based compensation arrangements were $3 million in 2023, $2 million in 2022, and $3 million in 2021.

As of December 31, 2023, there were approximately $31 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 2023, $25 million in 2022, and $22 million in 2021.

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)		
	2023	2022	2021	2023	2022	2021
Units granted	192,295	174,791	152,345	202,562	208,736	161,840
Weighted-average grant date fair value	$ 74.32	$ 69.66	$ 76.72	$ 79.61	$ 77.63	$ 82.42

(a) Units granted includes awards that will be cash settled of 0 in 2023, 0 in 2022, and 51,074 in 2021. See below for additional information on restricted stock unit grants.

(b) Reflects the target payout level.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2022	317,587		$ 73.91	330,694	$ 78.91
Granted	192,295		74.32	202,562	79.61
Vested	(119,077)		80.71	(169,290)	83.12
Forfeited (c)	(16,438)		73.95	(16,683)	78.40
Nonvested at December 31, 2023	374,367	(a)	73.29	347,283	77.29
Vested Awards Outstanding at December 31, 2023	70,766			155,708	

(a) Includes 34,367 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 $6 million, $3 million, and $4 million in 2023, 2022 and 2021, respectively. This includes cash used to settle restricted stock units of $3 million, $3 million, and $3 million in 2023, 2022 and 2021, 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, Clean and 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, Clean and Metric component at each balance sheet date. If the EPS, Clean and Metric component criteria are not ultimately achieved, no compensation cost is recognized relating to the EPS, Clean and 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.

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.

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, 2023**	**December 31, 2022**
Power	GWh	1,212	1,197
Gas	Billion cubic feet	200	149

Gains and Losses from Energy Derivative Instruments

For the years ended December 31, 2023, 2022 and 2021, 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):

Commodity Contracts	Financial Statement Location	Year Ended December 31, 2023	2022	2021
Net Gain (Loss) Recognized in Income	Fuel and purchased power (a)	$ (370,145)	$ 307,287	$ 216,847

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

Energy Derivative Instruments in the Consolidated Balance Sheets

Our energy derivative transactions are typically executed under standardized or customized agreements, which include collateral requirements and, in the event of a default, would allow for the netting of positive and negative exposures associated with a single counterparty. Agreements that allow for the offsetting of positive and negative exposures associated with a single counterparty are considered master netting arrangements. Transactions with counterparties that have master netting arrangements are offset and reported net on the Consolidated Balance Sheets. Transactions that do not allow for offsetting of positive and negative positions are reported gross on the Consolidated Balance Sheets.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 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.

As of December 31, 2022: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amounts Reported on Balance Sheets
Current assets	$ 103,484	$ (15,808)	$ 87,676	$ 28	$ 87,704
Investments and other assets	49,777	(5,383)	44,394	—	44,394
Total assets	153,261	(21,191)	132,070	28	132,098
Current liabilities	(47,670)	15,808	(31,862)	(5,835)	(37,697)
Deferred credits and other	(9,223)	5,383	(3,840)	—	(3,840)
Total liabilities	(56,893)	21,191	(35,702)	(5,835)	(41,537)
Total	$ 96,368	$ —	$ 96,368	$ (5,807)	$ 90,561

(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 $5,835 thousand and cash margin provided to counterparties of $28 thousand.

Interest Rate Derivatives

On October 19, 2022, Bright Canyon Energy entered into an interest rate swap to hedge the variable interest rate exposure relating to the credit agreement for the Los Alamitos project. The transaction qualified and had been designated as a cash flow hedge. The interest rate swap was included in the BCE Sale, and was assumed by Ameresco as part of the first stage of the closing. See Note 20. Prior to being transferred in the BCE Sale, the interest rate swap was in an asset position valued at $0.2 million. As of December 31, 2023, the interest rate swap has no impact on our Consolidated Balance Sheets.

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, 2023, we have no counterparties with positive exposures of greater than 10% of Pinnacle West's risk management assets. 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).

The following table provides information about our energy derivative instruments that have credit-risk-related contingent features (dollars in thousands):

	December 31, 2023
Aggregate fair value of derivative instruments in a net liability position	$ 128,711
Cash collateral posted	9,200
Additional cash collateral in the event credit-risk related contingent features were fully triggered (a)	117,566

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

We also have energy related non-derivative instrument contracts with investment grade credit-related contingent features, which could also require us to post additional collateral of approximately $205 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 2023, 2022 and 2021 (dollars in thousands):

	2023		2022		2021
Other income:					
Interest income	$ 27,242	(a)	$ 7,326		$ 6,726
Gain on Sale of BCE (Note 20)	6,205		—		—
Debt return on Four Corners SCR deferral (Note 3)	—		—		14,955
Debt return on Ocotillo modernization project (Note 3)	—		—		23,366
Miscellaneous	219		590		53
Total other income	$ 33,666		$ 7,916		$ 45,100
Other expense:					
Non-operating costs	$ (15,260)		$ (18,619)		$ (13,008)
Investment gains (losses) — net	(3,402)		(20,537)	(b)	(1,367)
Miscellaneous	(6,394)		(13,229)	(c)	(11,021)
Total other expense	$ (25,056)		$ (52,385)		$ (25,396)

(a) The 2023 interest income is primarily related to PSA Interest. See Note 3.
(b) The 2022 investment loss is primarily related to an impairment of PNW Power's Clear Creek wind farm investment. See Note 10.
(c) The 2022 miscellaneous amount includes donations of $7 million to the APS Foundation.

Other Income and Other Expense - APS

The following table provides detail of APS's other income and other expense for 2023, 2022 and 2021 (dollars in thousands):

	2023		2022		2021
Other income:					
Interest income	$ 26,853	(a)	$ 5,332		$ 4,692
Debt return on Four Corners SCR deferral (Note 3)	—		—		14,955
Debt return on Ocotillo modernization project (Note 3)	—		—		23,366
Miscellaneous	219		556		40
Total other income	$ 27,072		$ 5,888		$ 43,053
Other expense:					
Non-operating costs	$ (14,070)		$ (15,579)		$ (10,080)
Miscellaneous	(4,194)		(10,529)	(b)	(8,817)
Total other expense	$ (18,264)		$ (26,108)		$ (18,897)

(a) The 2023 interest income is primarily related to PSA Interest. See Note 3.
(b) The 2022 miscellaneous amount includes donations of $7 million to the APS Foundation.

17. Palo Verde Sale Leaseback Variable Interest Entities

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 2024 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 2023, 2022 and 2021, respectively. The increase in net income is entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

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

	December 31, 2023	December 31, 2022
Palo Verde sale leaseback property, plant and equipment, net of accumulated depreciation	$ 86,426	$ 90,296
Equity-Noncontrolling interests	107,198	111,229

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 $334 million beginning in 2024, 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, Coal Reclamation Escrow Account, and an Active Union Employee Medical Account. 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.

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 2023 and 2022, APS was reimbursed $14 million and $15 million, respectively, 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 liabilities. Activities relating to active union employee medical account investments are included within the other special use funds in the table below.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

APS

The following tables present the unrealized gains and losses based on the original cost of the investment and summarizes the fair value of APS's nuclear decommissioning trusts and other special use fund assets (dollars in thousands):

	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		$ 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.

	December 31, 2022					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 487,240	$ 66,974	$ 554,214		$ 334,817	$ (267)
Available for sale-fixed income securities	582,343	279,294	861,637	(a)	3,177	(68,795)
Other	3,827	963	4,790	(b)	—	(29)
Total	$ 1,073,410	$ 347,231	$ 1,420,641		$ 337,994	$ (69,091)

(a) As of December 31, 2022, the amortized cost basis of these available-for-sale investments is $927 million.
(b) Represents net pending securities sales and purchases.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table sets forth APS's realized gains and losses relating to the sale and maturity of available-for-sale debt securities and equity securities, and the proceeds from the sale and maturity of these investment securities (dollars in thousands):

	Year Ended December 31,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
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
2021			
Realized gains	$ 134,610	$ 49	$ 134,659
Realized losses	$ (8,431)	$ (7)	$ (8,438)
Proceeds from the sale of securities (a)	$ 1,457,305	$ 263,661	$ 1,720,966

(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, 2023, is as follows (dollars in thousands):

	Nuclear Decommissioning Trusts	Coal Reclamation Escrow Account	Active Union Employee Medical Account	Total
Less than one year	$ 26,057	$ 58,692	$ 36,857	$ 121,606
1 year – 5 years	225,891	46,120	152,761	424,772
5 years – 10 years	176,288	—	25,164	201,452
Greater than 10 years	353,097	—	—	353,097
Total	$ 781,333	$ 104,812	$ 214,782	$ 1,100,927

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, 2021	$ (53,885)		$ (976)	$ (54,861)
OCI (loss) before reclassifications	17,550		1,873	19,423
Amounts reclassified from accumulated other comprehensive loss	4,003	(a)	—	4,003
Balance at December 31, 2022	(32,332)		897	(31,435)
OCI (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)

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

Changes in Accumulated Other Comprehensive Loss — APS

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		Total
Balance at December 31, 2021	$ (34,880)		$ (34,880)
OCI (loss) before reclassifications	15,646		15,646
Amounts reclassified from accumulated other comprehensive loss	3,638	(a)	3,638
Balance at December 31, 2022	(15,596)		(15,596)
OCI (loss) before reclassifications	(3,383)		(3,383)
Amounts reclassified from accumulated other comprehensive loss	1,760	(a)	1,760
Balance at December 31, 2023	$ (17,219)		$ (17,219)

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

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 newly-formed, 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 first stage of the BCE Sale closed on August 4, 2023, with the carrying value of net assets transferred to Ameresco totaling $44 million, which included a $36 million construction term loan. See Note 6. The assets and liabilities transferred in this 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. Our Consolidated Income Statement for the year ended December 31, 2023, includes a pretax gain of $6 million relating to this stage of the BCE Sale reported within other income. Our Consolidated Balance Sheets as of December 31, 2023, includes a $28 million note receivable from Ameresco relating to this initial stage of the BCE Sale, which was received in full by Pinnacle West on January 29, 2024.

As of December 31, 2023, our Consolidated Balance Sheets also include $35 million of assets classified as held for sale, relating to the remaining assets of BCE that transferred to Ameresco on January 12, 2024, in the second stage of the sale. These assets held for sale include BCE's investment in the Kūpono Solar project, and other projects in various stages of development. The completion of the second stage of the BCE Sale was subject to various conditions precedent, including third-party consents which have been obtained. Prior to being classified as held for sale, these assets were primarily included in the other assets line item within the investments and other assets section on our Consolidated Balance Sheets. We measure assets held for sale at the lower of carrying value or fair value less cost to sell. For the year ended December 31, 2023, no impairment loss was recognized related to the assets classified as held for sale.

The purchase and sale agreement, as amended, provided for Pinnacle West to purchase, from Ameresco, approximately $28 million of investment tax credits that were generated by the assets included in the BCE Sale. The tax credits were purchased and transferred to Pinnacle West on January 30, 2024.

As of January 12, 2024, all stages of the BCE Sale have been completed. The purchase and sale agreement, as amended, allows Ameresco to make certain deferred payments relating to the BCE Sale throughout 2024. Pinnacle West continues to maintain certain performance guarantees relating to the BCE Kūpono Solar project 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 accounting standard was issued that changes disclosures relating to reportable segments. The new guidance expands the disclosure requirements relating to reportable segments, including requiring entities to disclose information about a reportable segment's significant expenses, among other changes. The amended guidance does not change how an entity identifies reportable segments or the accounting for segments. The new standard is effective for us, using a retrospective approach, on December 31, 2024, with early adoption permitted. The adoption of the new guidance may result in changes to our reportable segment disclosures, but will not impact our segment accounting or financial statement results.

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 changes require entities to include a tabular income tax rate reconciliation, disclose details on specific reconciliation categories and reconciling items, and disclose the amount of income taxes paid by jurisdiction, among other disclosure changes. The standard is effective for us on December 31, 2025, using a prospective approach, and may be early adopted. The adoption of the new guidance may result in changes to our income tax disclosures, but will not impact our accounting for income taxes 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,		
	2023	**2022**	**2021**
Operating expenses	$ 11,249	$ 8,850	$ 10,245
Other			
Equity in earnings of subsidiaries	539,962	500,042	628,916
Other income (expense)	2,823	(4,725)	(4,919)
Total	542,785	495,317	623,997
Interest expense	47,251	18,861	10,672
Income before income taxes	484,285	467,606	603,080
Income tax benefit	(17,272)	(15,996)	(15,640)
Net income attributable to common shareholders	501,557	483,602	618,720
Other comprehensive income (loss) — attributable to common shareholders	(1,709)	23,426	7,935
Total comprehensive income — attributable to common shareholders	$ 499,848	$ 507,028	$ 626,655

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,	
	2023	2022
ASSETS		
Current assets		
Cash and cash equivalents	$ 9	$ —
Accounts receivable	163,829	132,061
Income tax receivable	1,832	14,494
Assets held for sale- investment in subsidiaries	35,139	—
Other current assets	28,379	288
Total current assets	229,188	146,843
Investments and other assets		
Investments in subsidiaries	7,369,159	7,105,789
Deferred income taxes	15,746	1,521
Other assets	22,839	23,153
Total investments and other assets	7,407,744	7,130,463
TOTAL ASSETS	$ 7,636,932	$ 7,277,306
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 8,176	$ 6,499
Accrued taxes	4,543	7,694
Common dividends payable	99,813	97,895
Short-term borrowings	76,650	15,720
Current maturities of long-term debt	625,000	—
Operating lease liabilities	127	117
Other current liabilities	11,400	14,637
Total current liabilities	825,709	142,562
Long-term debt less current maturities	498,731	947,892
Pension liabilities	6,487	8,218
Operating lease liabilities	1,332	1,459
Other	19,811	17,299
Total deferred credits and other	27,630	26,976
COMMITMENTS AND CONTINGENCIES		
Common stock equity		
Common stock	2,744,491	2,719,735
Accumulated other comprehensive loss	(33,144)	(31,435)
Retained earnings	3,466,317	3,360,347
Total Pinnacle West Shareholders’ equity	6,177,664	6,048,647
Noncontrolling interests	107,198	111,229
Total Equity	6,284,862	6,159,876
TOTAL LIABILITIES AND EQUITY	$ 7,636,932	$ 7,277,306

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,		
	2023	**2022**	**2021**
Cash flows from operating activities			
Net income	$ 501,557	$ 483,602	$ 618,720
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of subsidiaries — net	(539,962)	(500,042)	(628,916)
Gain on sale relating to BCE	(6,423)	—	—
Depreciation and amortization	76	76	93
Deferred income taxes	(13,955)	17,256	(11,381)
Accounts receivable	(28,273)	(8,535)	8,897
Accounts payable	1,839	3,431	(2,598)
Accrued taxes and income tax receivables — net	9,505	(25,157)	16,079
Dividends received from subsidiaries	393,600	385,800	376,500
Other	(14,201)	47,719	4,214
Net cash flow provided by operating activities	303,763	404,150	381,608
Cash flows from investing activities			
Proceeds from sale relating to BCE	23,400	—	—
Investments in subsidiaries	(119,682)	(186,630)	(145,266)
Repayments of loans from subsidiaries and other	6,526	14,308	4,017
Advances of loans to subsidiaries	(59,349)	(3,308)	(12,256)
Net cash flow used for investing activities	(149,105)	(175,630)	(153,505)
Cash flows from financing activities			
Issuance of long-term debt	175,000	300,000	300,000
Short-term debt repayments under revolving credit facility	—	—	(19,000)
Short-term borrowings and (repayments) — net	60,930	2,420	(136,700)
Dividends paid on common stock	(386,486)	(378,881)	(369,478)
Repayment of long-term debt	—	(150,000)	—
Common stock equity issuance and purchases — net	(4,093)	(2,653)	(2,350)
Net cash flow used for financing activities	(154,649)	(229,114)	(227,528)
Net increase (decrease) in cash and cash equivalents	9	(594)	575
Cash and cash equivalents at beginning of year	—	594	19
Cash and cash equivalents at end of year	$ 9	$ —	$ 594

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.

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, 2023. 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, 2023. 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, 2023, 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, 2023, 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 22, 2024 (the “2024 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.

ITEM 11. EXECUTIVE COMPENSATION

Reference is hereby made to “Director Compensation,” “Executive Compensation,” and “Human Resources Committee Interlocks and Insider Participation” in the 2024 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 2024 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth information as of December 31, 2023, 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	1,485,075	—	3,535,951
Equity compensation plans not approved by security holders	—	—	—
Total	1,485,075	—	3,535,951

(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 2024 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 2024 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	2023	2022
Audit Fees (1)	$ 2,707,633	$ 2,653,737
Audit-Related Fees (2)	372,040	498,167
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 2022 and 2023 and environmental, social and governance assurance readiness performed in 2022.
(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 2023 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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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
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	Fifteenth Supplemental Indenture dated as of June 18, 2014	4.6i to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
4.6(m)	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
4.6(n)	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(o)	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(p)	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(q)	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(r)	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(s)	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(t)	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(u)	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
4.7	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	4.1 to APS's 1993 Form 10-K Report, File No. 1-4473	3/30/1994

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:[a]	Date Filed
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
10.1(2)	Pinnacle	Amended and Restated	10.1 to Pinnacle West's 1991	3/26/1992

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
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	10.1.2h to Pinnacle West's 2007 Form 10-K Report, File No. 1-8962	2/27/2008

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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	Pinnacle West	10.10A to APS's 1995	3/29/1996

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:[a]	Date Filed
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	First Amendment to	10.3.2a to Pinnacle West/APS	2/24/2017

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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	10.5.4 to Pinnacle West/APS 2012 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/22/2013

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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(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
10.6(5)(c)[bd]	Pinnacle West	Form of Restricted	10.2 to Pinnacle West/APS	5/3/2012

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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	Pinnacle West	Appendix A to the Proxy	4/01/2021

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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	10.2 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File Nos. 1-8962 and 1-4473	4/29/2011

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
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	10.107 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)(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	10.2 to Pinnacle West/APS March 31, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/2/2014

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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(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
10.12(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
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	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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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
10.12(2)(a)	Pinnacle West APS	Amendment No. 1, dated as of August 1, 1987, to Facility	4.13 to APS's Form 18 Registration Statement No. 33-9480 by means of	8/24/1987

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
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
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,	10.1 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/6/2010

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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		
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[c]	Pinnacle West	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		
32.2[c]	APS	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		
97	Pinnacle West	Policy Relating to Recovery of Erroneously Awarded Compensation		
99.1[c]	Pinnacle West APS	Participation Agreement, dated as of August 1, 1986, among	28.1 to APS's September 30, 1992 Form 10-Q Report, File No. 1-4473	11/9/1992

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
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
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	4.5 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
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
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	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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
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
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	28.7 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993

*

223

[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 27, 2024	/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	Principal Executive Officer and Director	February 27, 2024
(Jeffrey B. Guldner, Chairman of the Board of Directors, President and Chief Executive Officer)		
/s/ Andrew Cooper	Principal Financial Officer	February 27, 2024
(Andrew Cooper, Senior Vice President and Chief Financial Officer)		
/s/ Elizabeth A. Blankenship	Principal Accounting Officer	February 27, 2024
(Elizabeth A. Blankenship, Vice President, Controller and Chief Accounting Officer)		

/s/ Glynis A. Bryan	Director	February 27, 2024
(Glynis A. Bryan)		
/s/ Gonzalo A. de la Melena, Jr.	Director	February 27, 2024
(Gonzalo A. de la Melena, Jr.)		
/s/ Richard P. Fox	Director	February 27, 2024
(Richard P. Fox)		
/s/ Kathryn L. Munro	Director	February 27, 2024
(Kathryn L. Munro)		
/s/ Bruce J. Nordstrom	Director	February 27, 2024
(Bruce J. Nordstrom)		
/s/ Paula J. Sims	Director	February 27, 2024
(Paula J. Sims)		
/s/ William H. Spence	Director	February 27, 2024
(William H. Spence)		
/s/ Kristine L. Svinicki	Director	February 27, 2024
(Kristine L. Svinicki)		
/s/ James E. Trevathan, Jr.	Director	February 27, 2024
(James E. Trevathan, Jr.)		

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 27, 2024	/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	Principal Executive Officer	February 27, 2024
(Jeffrey B. Guldner, Chairman	and Director	
of the Board of Directors and		
Chief Executive Officer)		
/s/ Andrew Cooper	Principal Financial Officer	February 27, 2024
(Andrew Cooper,		
Senior Vice President and		
Chief Financial Officer)		
/s/ Elizabeth A. Blankenship	Principal Accounting Officer	February 27, 2024
(Elizabeth A. Blankenship		
Vice President, Controller and		
Chief Accounting Officer)		

/s/ Glynis A. Bryan	Director	February 27, 2024
(Glynis A. Bryan)		
/s/ Gonzalo A. de la Melena, Jr.	Director	February 27, 2024
(Gonzalo A. de la Melena, Jr.)		
/s/ Richard P. Fox	Director	February 27, 2024
(Richard P. Fox)		
/s/ Kathryn L. Munro	Director	February 27, 2024
(Kathryn L. Munro)		
/s/ Bruce J. Nordstrom	Director	February 27, 2024
(Bruce J. Nordstrom)		
/s/ Paula J. Sims	Director	February 27, 2024
(Paula J. Sims)		
/s/ William H. Spence	Director	February 27, 2024
(William H. Spence)		
/s/ Kristine L. Svinicki	Director	February 27, 2024
(Kristine L. Svinicki)		
/s/ James E. Trevathan, Jr.	Director	February 27, 2024
(James E. Trevathan, Jr.)		