

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, 2022

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number	Exact Name of Each Registrant as specified in its charter; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
1-8962	PINNACLE WEST CAPITAL CORPORATION (an Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix Arizona 85072-3999 (602) 250-1000	86-0512431
1-4473	ARIZONA PUBLIC SERVICE COMPANY (an Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix Arizona 85072-3999 (602) 250-1000	86-0011170

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

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

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

ARIZONA PUBLIC SERVICE COMPANY Common Stock, Par Value \$2.50 per share

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

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

Indicate by check mark whether each 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, smaller reporting company or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

PINNACLE WEST CAPITAL CORPORATION					
Large accelerated filer	☒	Accelerated filer	☐	Non-accelerated filer	☐
Emerging growth company	☐				
ARIZONA PUBLIC SERVICE COMPANY					
Large accelerated filer	☐	Accelerated filer	☐	Non-accelerated filer	☒
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. ☒

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

PINNACLE WEST CAPITAL CORPORATION	\$	8,247,902,707	as of June 30, 2022
ARIZONA PUBLIC SERVICE COMPANY	\$	0	as of June 30, 2022

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, 2023:	113,175,507
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, \$2.50 par value, outstanding as of February 21, 2023:	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 17, 2023 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.

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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.

GLOSSARY OF NAMES AND TECHNICAL TERMS

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, a subsidiary of the Company
CAISO	California Independent System Operator
CCR	Coal combustion residuals
Cholla	Cholla Power Plant
COVID-19	2019 Novel Coronavirus
DC	Direct Current
distributed renewable energy systems or 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
El Paso	El Paso Electric 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)
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
TOU	Time of Use
TEAM	Tax expense adjustor mechanism
VIE	Variable interest entity

FORWARD-LOOKING STATEMENTS

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

- the current economic environment and its effects, such as lower economic growth, a tight labor market, 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 facility 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 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.

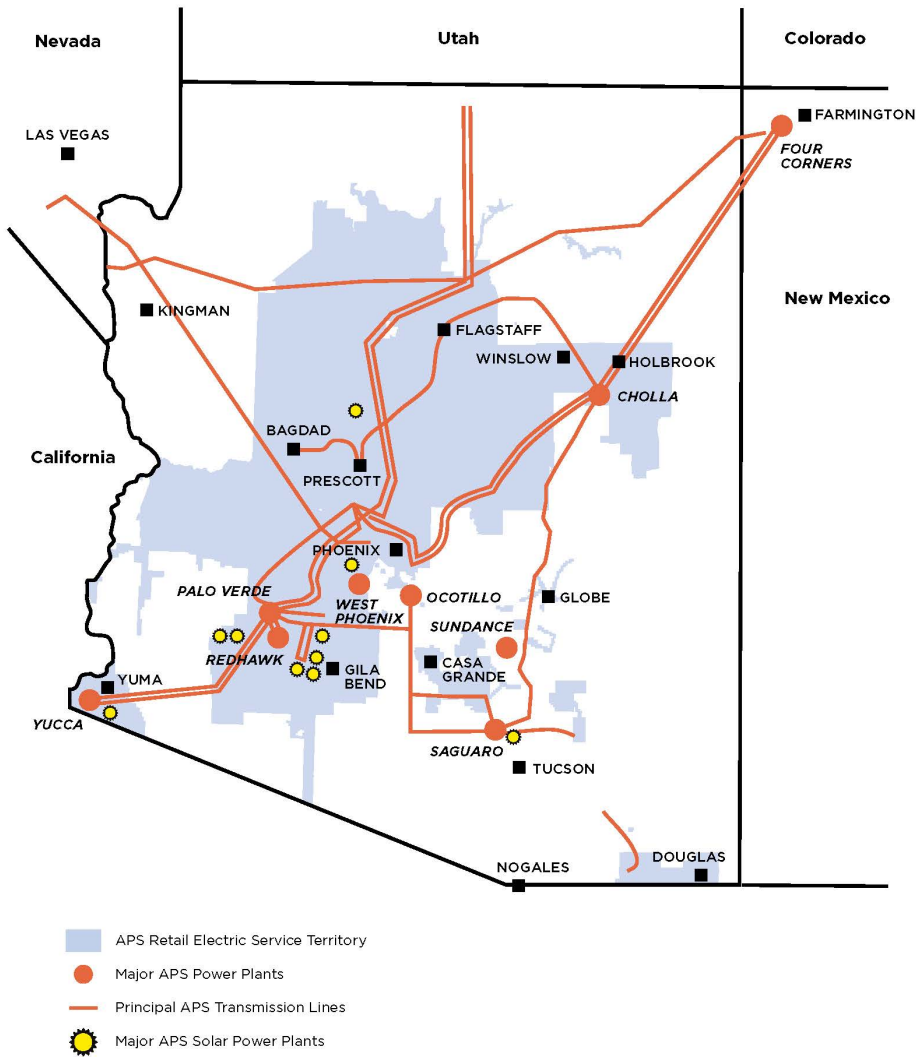
Pinnacle West's other subsidiaries are El Dorado, BCE and 4CA. Additional information related to these subsidiaries is provided later in this report.

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

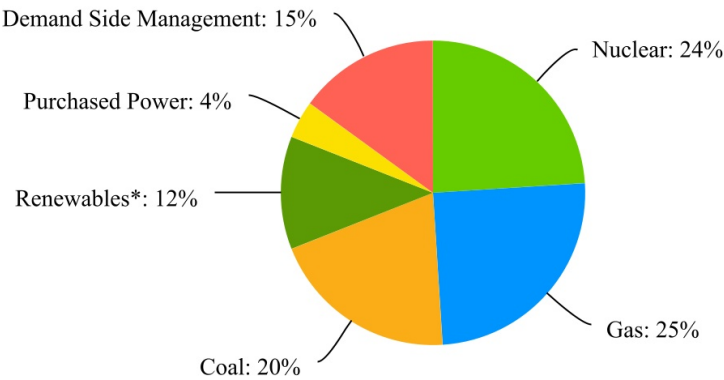
APS currently provides electric service to approximately 1.3 million customers. We own or lease 6,340 MW of regulated generation capacity and we hold a mix of both long-term and short-term purchased power agreements for additional capacity, including a variety of agreements for the purchase of renewable energy. During 2022, no single purchaser or user of energy accounted for more than 2.4% of our electric revenues.

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



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 2022 were as follows:



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

The share of APS’s energy supply being derived from clean resources is 51%, which includes energy from nuclear, renewables and DSM.

BCE also has acquired minority ownership positions in two wind farms that achieved commercial operation in 2020. Both wind farms deliver power under long-term PPAs. See “Business of Other Subsidiaries — Bright Canyon Energy” below for information regarding BCE’s investments.

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 goals consist of three parts:

- a 2050 goal to provide 100% clean, carbon-free electricity;
- a 2030 target of achieving a resource mix that is 65% clean energy, with 45% of the generation portfolio coming from renewable energy; and
- a commitment to end APS's use of coal-fired generation by 2031.

Among other strategies, APS intends to achieve these goals through various methods such as relying on Palo Verde, the nation's largest producer of carbon-free energy; increasing clean energy resources, including renewables; developing energy storage; ceasing the use of 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 EPA under the EPA GHG Reporting Program. APS also voluntarily tracks APS's GHG emissions arising from APS operations. In addition to reporting to the EPA, we publicly report Scope 1, 2 and 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 2030 and 40% through 2031; 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 do 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 Court of Federal Claims. This lawsuit sought to recover damages incurred due to the 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, as it was required to do pursuant to the terms of the Standard Contract and the NWPA. On August 18, 2014, APS and the DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment by the DOE to 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, 2022. An additional extension is currently pending.

APS has submitted eight claims pursuant to the terms of the August 18, 2014 settlement agreement for eight separate time periods during July 1, 2011 through June 30, 2021. The DOE has approved and paid \$123.9 million for these claims (APS's share is \$36 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, 2022, APS filed its ninth claim pursuant to the terms of the August 18, 2014, settlement agreement in the amount of \$14.3 million (APS's share is \$4.2 million). In February 2023, the DOE approved 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 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: Fairview, 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 2049. 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. Additionally, 4CA, a wholly-owned subsidiary of Pinnacle West, owned 7% of Units 4 and 5 from July 2016 through July 2018 following its acquisition of El Paso's interest in these units described below. As part of APS's Clean Energy Commitment, APS has committed to cease using 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"). El Paso, a 7% owner of Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS agreed to assume the 7% shortfall obligation. On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in each of Units 4 and 5 of Four Corners. 4CA purchased the El Paso interest on July 6, 2016. The purchase price was immaterial in amount, and 4CA assumed El Paso's reclamation and decommissioning obligations associated with the 7% interest.

On June 29, 2018, 4CA and NTEC entered into an asset purchase agreement providing for the sale to NTEC of 4CA's 7% interest in Four Corners. NTEC assumed 4CA's reclamation and decommissioning obligations associated with the 7% interest. The sale transaction closed on July 3, 2018. NTEC purchased the 7% interest at 4CA's book value, approximately \$70 million and paid the purchase price over 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.

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 beginning in 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 when 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. APS anticipates that it will elect not to begin seasonal operation in November 2023, unless market conditions change.

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 by 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, 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 distributed renewable energy 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 distributed renewable energy 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 11 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.

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.

In 2018, APS issued a request for proposal (“RFP”) for approximately 106 MW of energy storage to be located at up to five of its AZ Sun sites. Based upon its evaluation of the RFP responses, APS decided to expand the initial phase of battery deployment to 141 MW by adding a sixth AZ Sun site. These battery storage facilities are currently expected to be in service during the first quarter of 2023. On August 2, 2021, APS executed a contract for an additional 60 MW of utility-owned energy storage to be located on APS’s AZ Sun sites. This contract, with a 2023 in-service date, will complete the addition of storage on current APS-owned utility-scale solar facilities.

Additionally, in February 2019, APS signed two 20-year PPAs for energy storage totaling 150 MW. These PPAs were subject to ACC approval in order to allow for cost recovery through the PSA. APS received the requested ACC approval on January 12, 2021, and service under the agreements is expected to begin in 2023.

In December 2020, APS issued two RFPs (collectively, the “December 2020 RFPs”). As a result of the December 2020 RFPs, APS executed four 20-year PPAs for resources that include energy storage: (a) two PPAs for standalone energy storage resources totaling 300 MW; and (b) two PPAs for solar plus storage resources totaling 275 MW. The PPAs are also subject to ACC approval to enable cost recovery through the PSA. APS received the requested ACC approval for three out of four of the projects on December 16, 2021 and on April 13, 2022 for the remaining project. Service under the agreements is expected to begin in 2023 and 2024.

In May 2022, APS issued an RFP to address resource needs for 2025 and beyond (the “2022 RFP”). As a result of the 2022 RFP, as of January 2023, APS has executed a 20-year PPA for solar plus storage resources totaling 300 MW. The PPA is subject to ACC approval to enable cost recovery through the PSA, which was requested in December 2022 and approved in February 2023. Service under this agreement is expected to begin in 2025.

APS currently plans to install more than 1,200 MW of energy storage by 2025, including the energy storage projects under PPAs and AZ Sun retrofits described above. The remaining energy storage is expected to be made up of 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, 2022. Agreements for the development and completion of future resources are subject to various conditions.

	Net Capacity in Operation (MW)	Net Capacity Planned / Under Development (MW)
APS Owned Energy Storage	—	201
PPAs Energy Storage	—	1,025
Residential Energy Storage	19(a)	7
Total Energy Storage Portfolio	19	1,233

(a) This includes 18.5 MW of APS customer-owned batteries and 0.2 MW of APS-owned residential batteries.

Renewable Energy Portfolio

To date, APS has a diverse portfolio of existing and planned renewable resources totaling 3,894 MW, including solar, wind, geothermal, biomass and biogas. Of this portfolio, 2,418 MW are currently in operation and 1,476 MW are under contract for development or are under construction. Renewable resources in operation include 264 MW of facilities owned by APS, 736 MW of long-term purchased power agreements, and an estimated 1,418 MW of customer-sited, third-party owned distributed energy resources.

As previously discussed, in May 2022, APS issued an RFP to address resource needs for 2025 and beyond. The 2022 RFP solicits competitive proposals for approximately 1,000 MW to 1,500 MW of resources, including up to 600 MW to 800 MW of renewable resources to meet the needs of 2025 and 2026 while also considering resources that can be online as late as 2027. The 2022 RFP stopped accepting bids on July 15, 2022, and APS sent notifications to shortlisted bidders on September 23, 2022. As a result of the 2022 RFP, and as of December 31, 2022, APS has signed a PPA for 300 MW of solar plus energy storage resources and a PPA for 216 MW of wind resources. Once APS secures those important resources and closes out the 2022 RFP, APS intends to issue APS's next RFP to address future resource needs.

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" above 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, 2022. 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					
<i>Solar:</i>					
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
<i>Distributed Energy:</i>					
APS Owned (a)	AZ	Various		36	
Total APS Owned				264	150
Purchased Power Agreements					
<i>Solar:</i>					
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 A	Coconino County, AZ	2023	18		80
CO Bar Solar B	Coconino County, AZ	2023	18		80
Mesquite Solar 5	Tonopah, AZ	2023	20		60
Sunstreams 3	Arlington, AZ	2024	20		215
Sunstreams 4	Arlington, AZ	2025	20		300
<i>Wind:</i>					
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
<i>Geothermal:</i>					
Salton Sea	Imperial County, CA	2006	23	10	
<i>Biomass:</i>					
Snowflake	Snowflake, AZ	2008	25	14	
<i>Biogas:</i>					
NW Regional Landfill	Surprise, AZ	2012	20	3	
Total Purchased Power Agreements				736	1,189
Distributed Energy					
<i>Solar (b)</i>					
Third-party Owned	AZ	Various		1,385	137
Agreement 1	Bagdad, AZ	2011	25	15	
Agreement 2	AZ	2011-2012	20-21	18	
Total Distributed Energy				1,418	137
Total Renewable Portfolio				2,418	1,476

- (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.

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, 2022, 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, 2023	45
Demand Response Agreement	Summer seasons through 2025	75
Tolling Agreement	May 1 through October 31, 2021-2027	463
Tolling Agreement	Summer seasons from Summer 2020 through Summer 2025	565
Tolling Agreement	June 1 through September 30, 2020-2026	570
Renewable Energy (b)	Various	736

- (a) Up to 45 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 — Renewable Energy Portfolio.”

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 2022 peak one-hour demand on its electric system was recorded on July 11, 2022, at 7,587 MW, compared to the 2021 peak of 7,580 MW recorded on June 18, 2021. APS’s reserve margin at the time of the 2022 peak demand, calculated using system load serving capacity, was 13%. For 2023, due to expiring purchased power contracts, APS is procuring market resources to maintain its minimum 15% 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 requirements and whether it should be acknowledged. Based on an ACC decision, APS was originally required to file its IRP by April 1, 2020. On February 20, 2020, the ACC extended the deadline for all utilities to file their IRPs from April 1, 2020, to June 26, 2020. On June 26, 2020, APS filed its final IRP. On July 15, 2020, the ACC extended the schedule for final ACC review of utility IRPs to February 2021. In February 2022, the ACC acknowledged APS’s IRP. 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. Due to current projected future resource needs and load forecasts, APS continues to need to develop or acquire additional capacity. APS intends to file its next IRP later in 2023.

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.

Energy Imbalance Market & Wholesale Market

In 2016, APS began to participate in the Energy Imbalance Market (“EIM”), a voluntary, real-time optimization market operated by the CAISO. The EIM 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 EIM 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 in discussions with the EIM operator, CAISO, and other EIM participants about the feasibility of creating a voluntary day-ahead market to achieve more cost savings and use the region’s renewable resources more efficiently. APS also is in discussions with Southwest Power Pool, a market operator developing a day-ahead and real-time market for the Western Interconnection. In addition, APS is participating in the Western Resource Adequacy Program administered by the 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 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, Commissioners voted to postpone a decision on the All-Source RFP and IRP rulemaking package until 2023. 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 distributed renewable energy 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 to convene and develop a community solar program for the Commission’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 is proposing 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. The community solar program was 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 on November 10, 2022, the ACC approved the 2023 RES Implementation Plan, including APS’s requested waiver of the distributed energy requirement for 2023. 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 and intends to intervene to contest it. On November 3, 2021, the ACC submitted questions to the Office of 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.

On October 28, 2021, an ACC Commissioner docketed a letter directing ACC Staff and interested stakeholders to design a 200-300 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 2022, approximately 11.6% 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. 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 ("CO₂") 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 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.

On June 19, 2019, EPA took final action on its proposals to repeal EPA’s 2015 Clean Power Plan (“CPP”) and replace those regulations with a new rule, the Affordable Clean Energy (“ACE”) regulations. EPA originally finalized the CPP on August 3, 2015, and such rules would have had far broader impact on the electric power sector than the ACE regulations. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new existing power plant carbon regulations consistent with the court’s ruling. That decision, which endorsed an expansive view of the federal Clean Air Act consistent with EPA’s 2015 CPP, was subsequently reversed by the U.S. Supreme Court on June 30, 2022. While the current administration has expressed its intent to develop new carbon emission regulations governing existing power plants sometime in 2023, such action will be constrained by the U.S. Supreme Court’s decision that the CPP violated the Clean Air Act. Nonetheless, we cannot at this time predict the outcome of pending EPA rulemaking proceedings related to carbon emissions from existing power plants.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standards (“NAAQS”) and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, RCRA, Superfund, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of our coal 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 fossil-fuel powered 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

Regional Haze Rules. In 1999, EPA announced regional haze rules to reduce visibility impairment in national parks and wilderness areas. The rules require states (or, for sources located on tribal land, EPA) to determine what pollution control technologies constitute the BART for certain older major stationary sources, including fossil-fuel fired power plants. EPA subsequently issued the Clean Air Visibility Rule, which provides guidelines on how to perform a BART analysis. Final regulations imposing BART requirements have now been imposed on each APS coal-fired power plant. Four Corners was required to install new pollution controls to comply with BART, while similar pollution control installation requirements were not necessary for Cholla.

Cholla. In early 2017, EPA approved a final rule containing a revision to Arizona’s State Implementation Plan (“SIP”) for Cholla that implemented BART requirements for this facility, which did not require the installation of any new pollution control capital improvements. In conjunction with the closure of Cholla Unit 2 in 2015, APS has committed to ceasing coal combustion within Units 1 and 3 by

April 2025. PacifiCorp retired Cholla Unit 4 at the end of 2020. See “Cholla” in Note 3 for information regarding future plans for Cholla and details related to the resulting regulatory asset.

Four Corners. Based on EPA’s final standards, APS’s 63% share of the cost of required BART controls for Four Corners Units 4 and 5 was approximately \$400 million, which has been incurred. See Note 3 for information regarding the related rate recovery. In addition, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso’s 7% interest in Four Corners Units 4 and 5. 4CA purchased the El Paso interest on July 6, 2016. NTEC purchased the interest from 4CA on July 3, 2018. The cost of the pollution controls related to the 7% interest is approximately \$45 million, which was assumed by NTEC through its purchase of the 7% interest.

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, including supporting the passage of new state legislation 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. 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, the Company’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 2023.

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 APS's financial position, results of operations, or cash flows.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately \$30 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately \$16 million. 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. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from \$10 million to \$15 million, which would be incurred over 30 years. The analysis needed to perform a similar cost estimate for Cholla remains ongoing at this time. 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 process, we cannot predict any ultimate impacts to the Company; however, at this time we do not believe the cost estimates for Cholla and any potential change to the cost estimate for Four Corners would have a material impact on our financial position, results of operations, or cash flows.

Effluent Limitation Guidelines. On September 30, 2015, EPA finalized revised effluent limitation guidelines ("ELG") establishing technology-based wastewater discharge limitations for fossil-fired EGUs. EPA's final regulation targets metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and coal ash disposal leachate. Based upon an earlier set of preferred alternatives, the final effluent limitations generally require chemical precipitation and biological treatment for flue gas desulfurization scrubber wastewater, "zero discharge" from fly ash and bottom ash handling, and impoundment for coal ash disposal leachate.

On August 11, 2017, EPA announced that it would be initiating rulemaking proceedings to potentially revise the September 2015 ELGs. On September 18, 2017, EPA finalized a regulation postponing the earliest date on which compliance with the ELGs for these waste-streams would be required from November 1, 2018, until November 1, 2020. At this time, APS's National Pollutant Discharge Elimination System ("NPDES") discharge permit for Four Corners contains a December 31, 2023,

compliance deadline for achieving “zero discharge” of bottom ash transport waters. Nonetheless, on October 13, 2020, EPA published a final rule relaxing these “zero discharge” limitations for bottom ash handling water and allowing for approximately 10% of such wastewater to be discharged (on a volumetric, 30-day rolling average basis) under limited power plant operating scenarios. At this time, APS is pursuing a modification to the Four Corners NPDES discharge permit in order to implement the most recent ELG rulemaking. We cannot at this time predict the outcome of this permit modification proceeding, including any public commenting or permit appeal procedures. The Cholla facility does not require NPDES permitting.

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 the Company. APS will continue to monitor these standards as they are implemented within the jurisdictions affecting APS.

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.

On August 6, 2013, the Roosevelt Irrigation District (“RID”) filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID’s groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS’s current and former ownership of facilities in and around OU3. As part of a

state governmental investigation into groundwater contamination in this area, on January 25, 2015, 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. On December 16, 2016, two RID environmental and engineering contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another RID service provider filed an additional ancillary CERCLA lawsuit against certain of the defendants in the main RID litigation but excluded APS and certain other parties as named defendants. Because the ancillary lawsuits concern past costs allegedly incurred by these RID vendors, which were ruled unrecoverable directly by RID in November of 2016, the additional lawsuits do not increase APS's exposure or risk related to these matters.

On April 5, 2018, RID and the defendants in that particular litigation executed a settlement agreement, fully resolving RID's CERCLA claims concerning both past and future cost recovery. APS's share of this settlement was immaterial. In addition, the two environmental and engineering vendors voluntarily dismissed their lawsuit against APS and the other named defendants without prejudice. An order to this effect was entered on April 17, 2018. With this disposition of the case, the vendors may file their lawsuit again in the future. On August 16, 2019, Maricopa County, one of the three direct defendants in the ancillary service provider lawsuit, filed a third-party complaint seeking contribution for its liability, if any, from APS and 28 other third-party defendants. While this lawsuit remains pending, on September 30, 2022, the U.S. District Court for the District of Arizona granted partial summary judgment to the direct defendants for \$20.6 million of the \$21 million in CERCLA response costs claimed by the service provider. We are unable to predict the outcome of any further litigation related to the remaining response costs at issue in this litigation; however, we do not expect the outcome to have a material impact on our financial position, results of operations, or cash flows.

On February 28, 2022, EPA provided APS with a request for information under CERCLA related to APS's Ocotillo power plant site located in Tempe, Arizona. In particular, EPA seeks information from APS regarding APS's use, storage, and disposal of substances containing per-and polyfluoroalkyl ("PFAS") compounds at the Ocotillo power plant site in order to aid EPA's investigation into actual or threatened releases of PFAS into groundwater within the South Indian Bend Wash ("SIBW") Superfund site. The SIBW Superfund site includes the APS Ocotillo power plant site. APS filed its response to this information request on April 29, 2022. On January 17, 2023, EPA contacted APS to inform APS that it would be commencing on-site investigations within the SIBW site, including the Ocotillo power plant, and performing a remedial investigation and feasibility study related to potential PFAS impacts to groundwater over the next two to three years. At the present time, we are unable to predict the outcome of this matter and expenditures related to this matter cannot be reasonably estimated.

Manufactured Gas Plant Sites. Certain properties which APS now owns or which were previously owned by it or its corporate predecessors were at one time sites of, or sites associated with, manufactured gas plants. APS is taking action to voluntarily remediate these sites. APS does not expect these matters to have a material adverse effect on its financial position, results of operations, or cash flows.

Four Corners National Pollutant Discharge Elimination System Permit

On July 16, 2018, several environmental groups filed a petition for review before the EPA Environmental Appeals Board ("EAB") concerning the NPDES wastewater discharge permit for Four Corners, which was reissued on June 12, 2018. The environmental groups allege that the permit was reissued in contravention of several requirements under the Clean Water Act and did not contain required provisions concerning EPA's 2015 revised ELGs for steam-electric EGUs, 2014 existing-source

regulations governing cooling-water intake structures, and effluent limits for surface seepage and subsurface discharges from coal-ash disposal facilities. To address certain of these issues through a reconsidered permit, EPA took action on December 19, 2018, to withdraw the NPDES permit reissued in June 2018. Withdrawal of the permit moots the EAB appeal, and EPA filed a motion to dismiss on that basis. The EAB thereafter dismissed the environmental group appeal on February 12, 2019. EPA then issued a revised final NPDES permit for Four Corners on September 30, 2019. Based upon a November 1, 2019, filing by several environmental groups, the EAB again took up review of the Four Corners NPDES Permit. Oral argument on this appeal was held on September 3, 2020, and 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 this 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 is not expected to have a material impact on APS's financial position, results of operations, or cash flows.

Water Supply

Based on a declaration from the U.S. Bureau of Reclamation, as of January 1, 2023, Arizona's supply of Colorado River water will be subject to a Tier 2a shortage. This shortage will result in a reduction to Arizona's share of the Colorado River water by 22 percent or 592,000-acre feet. This reduction, similar to the 2022 tier 1 shortage, 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 2a 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 position, 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. 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.

Diversity, Equity, and Inclusion

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 ten 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 2022, 44% of external hires were ethnically or racially diverse, 40% were female and 7% were veterans. Additionally, as of December 31, 2022, 35% of our employees are ethnically or racially diverse, 26% are female, and 15% are veterans. Finally, as of December 31, 2022, 39% of the Company's officers are female, and 18% are ethnically or racially diverse.

Succession Planning

Through a strong focus on succession planning, we ensure that our Company is prepared to fill executive and other key leadership roles with capable, experienced employees. We continually revisit and revise succession plans to make certain that qualified individuals are in place to move into critical positions. We have strategically selected successors for our management team to lead our Company into the future with strong and sustainable performance. In addition, we assure that each business unit of the Company has talent management strategies and development plans to meet its future leadership needs. Effective succession planning helps us identify employees with leadership potential and also allows us to evaluate any gaps in education, skills and experience that need to be addressed to prepare those employees to move into leadership roles. At management review meetings, officers and directors review how business units are addressing succession planning, leadership opportunities, and retirement projections.

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 2022, we graduated 138 individuals from our three academies (Leadership Academy, Impact and Influence Academy, and Strategic Leadership Academy). Additionally, our Learning and Development organization was recognized as a top training organization, earning an APEX Award from Training Magazine.

Talent pipelines help sustain our skilled workforce needs. Pipeline strategies include our apprentice and rotational programs. Additionally, our recruiters target specific colleges and programs of study that we have identified as talent pipelines. In 2022, we hosted 54 summer interns with a diversity rate of 63%.

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

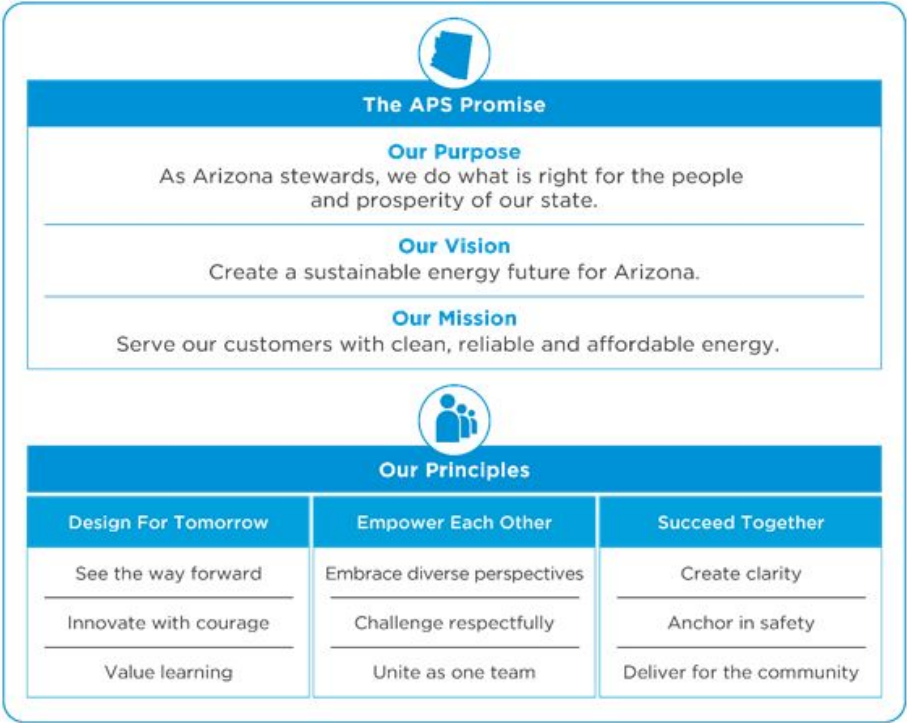
personal well-being and professional satisfaction. We are committed to providing programs that matter to our employees throughout various life and career phases.

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. In 2019, we integrated our employee experience surveys with onboarding surveys and exit interviews. Bringing together these elements allows us to get a more complete picture of the experience of our employees, from the time they join the Company until they decide to leave.

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.



BUSINESS OF OTHER SUBSIDIARIES

Bright Canyon Energy

On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE’s strategy is to develop, own, operate and acquire energy infrastructure in a manner that leverages the Company’s core expertise in the electric energy industry. As of December 31, 2022, BCE had total assets of approximately \$115.3 million.

In 2014, BCE formed a 50/50 joint venture with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. The joint venture, named 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.

On December 20, 2019, BCE acquired minority ownership positions in two wind farms under development by Tenaska Energy, Inc. and Tenaska Energy Holdings, LLC, the 242 MW Clear Creek wind farm in Missouri (“Clear Creek”) and the 250 MW Nobles 2 wind farm in Minnesota (“Nobles 2”). Clear Creek achieved commercial operation in May 2020 and Nobles 2 achieved commercial operation in December 2020. Both wind farms deliver power under long-term PPAs. BCE indirectly owns 9.9% of Clear Creek and 5.1% of Nobles 2.

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 and filed a complaint with FERC on May 21, 2021, which was denied on September 9, 2022. Subsequently, Tenaska Clear Creek Wind, LLC filed with FERC a request for rehearing and a motion for stay of the September 9, 2022 order. On October 7, 2022, the request for rehearing was denied by FERC. FERC has not ruled on the motion for stay. Clear Creek has filed a Petition for Review with the U.S. Court of Appeals and Motion for Stay Pending Appeal, both of which are still pending.

Tenaska Clear Creek Wind, LLC filed a second complaint with FERC on May 25, 2022, alleging that the wind farm was being curtailed in a discriminatory manner. The May 25, 2022 Complaint was denied by FERC on December 15, 2022 and Tenaska Clear Creek Wind, LLC requested Rehearing of the denial on January 13, 2023.

Due to the disputed system upgrades and the related curtailment, 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. These energy curtailments are expected to persist, unless and until system upgrades are implemented to alleviate the present transmission system congestion, or the disputes are determined in favor of, or settled in a manner favorable to, Tenaska Clear Creek Wind, LLC. As such, during the fourth quarter of 2022, due to these on-going disputes, cost allocation uncertainties, and no probable favorable resolution, BCE determined its equity method investment was fully impaired. Prior to the impairment, the investment had a carrying value of \$17.1 million, which has been 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 has started construction on a microgrid facility in Los Alamitos, California (“Los Alamitos”) featuring 31 MW of solar, 20 MW of battery storage, and 3 MW of backup generators. Supported by a long-term PPA with San Diego Gas and Electric Company, Los Alamitos will supply 20 MW of solar and battery storage capacity to the Southern California grid and provide resilient backup power in the event of a grid emergency to the Army and California National Guard at Joint Forces Training Base Los Alamitos. The Los Alamitos project is scheduled to achieve commercial operation in third-quarter 2023. See Note 6 regarding a credit agreement entered into by BCE to finance capital expenditures and related costs for this microgrid project.

BCE and Ameresco, Inc. jointly own 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 PPA with Hawaiian Electric Company, Inc. The Kūpono Solar project is expected to be completed in 2024.

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. El Dorado is actively seeking to prudently realize the value of these investments. In particular, El Dorado committed to a \$25 million investment in the Energy Impact Partners fund, which is an organization that focuses on fostering innovation and supporting the transformation of the utility industry. The investment will be made by El Dorado as investments are selected by the Energy Impact Partners fund. As of December 31, 2022, El Dorado has contributed approximately \$12.5 million to the Energy Impact Partners fund. Additionally, El Dorado committed to a \$25 million investment in AZ-VC (formerly invisionAZ Fund), which 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 the State of Arizona, or based in other jurisdictions and having existing or potential strategic or economic ties to companies or other interests in the State of Arizona. As of December 31, 2022, El Dorado has contributed approximately \$2.6 million to the AZ-VC. The remainder of the investments will be contributed by El Dorado as investments are selected by the AZ-VC.

Pinnacle West, APS and El Dorado are all incorporated in the State of Arizona. BCE and 4CA are 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, 2022
Pinnacle West	400 North Fifth Street Phoenix, AZ 85004	1985	82
APS	400 North Fifth Street P.O. Box 53999 Phoenix, AZ 85072-3999	1920	5,772
BCE	400 East Van Buren Street Phoenix, AZ 85004	2014	7
El Dorado	400 East Van Buren Street Phoenix, AZ 85004	1983	—
4CA	400 East Van Buren Street Phoenix, AZ 85004	2016	—
Total			5,861

The APS number includes employees at jointly-owned generating facilities (approximately 2,059 employees) for which APS serves as the generating facility manager. Approximately 1,162 APS employees are union employees, represented by the International Brotherhood of Electrical Workers (“IBEW”). In March 2020, the Company concluded negotiations with the IBEW and approved a three-year extension of the contract set to expire on April 1, 2020. Under the extension, union members received wage increases for 2020, 2021 and 2022; there were no other changes. The current contract expires on April 1, 2023, and APS and the IBEW are currently engaged in negotiations to renew the contract.

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 law 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 a Superfund site 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, 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, 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.

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.

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 CO₂, 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. In 2015, EPA finalized a rule to limit CO₂ emissions from existing power plants, the Clean Power Plan, or CPP. The implementation of this rule within the jurisdictions where APS operates would have resulted in a shift in generation from coal to more natural gas and renewable generation. Because of a view that the federal Clean Air Act did not permit such an expansive use of administrative authority over utility generation resources, in 2019 regulations were issued that repealed the CPP and replaced it with a far narrower set of regulations focused solely on coal-fired power plant efficiency improvements. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new regulations governing carbon emissions from existing power plants consistent with the court's ruling. That decision, which endorsed an expansive view of the federal Clean Air Act consistent with the CPP, was subsequently reversed by the U.S. Supreme Court on June 30, 2022. While the current administration has expressed its intent to develop new carbon emission regulations governing existing power plants in 2023, such action will be constrained by the U.S. Supreme Court's decision that the CPP violated the Clean Air Act.

Depending on the outcome of future carbon emission rulemakings 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 imposing 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 southwest 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 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 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 upon 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 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 2.1% for the year ended December 31, 2022, compared with the prior-year period. For the three years through 2022, APS's customer growth averaged 2.2% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2023 and the average annual growth to be in the range of 1.5% to 2.5% through 2025 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 2.4% for the year ended December 31, 2022, compared with the prior-year period. While steady customer growth was offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives, the main drivers of positive sales for this period were a strong improvement in sales to commercial and industrial customers and the ramp-up of new data center customers.

For the three years through 2022, annual retail electricity sales growth averaged 2.5%, adjusted to exclude the effects of weather variations. Due to the expected rapid 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 3.5% to 5.5% for 2023 and that average annual growth will be in the range of 4.5% to 6.5% through 2025, including the effects of customer conservation, energy efficiency, and distributed renewable generation initiatives, but excluding the effects of weather variations. This projected sales growth range includes the impacts of several large data centers and new large manufacturing facilities, which are expected to contribute to average annual growth in the range of 3.5% to 5.5% through 2025.

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,

and responses to retail price changes. 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, which could materially affect 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 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.

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

Wildfires have the potential to affect the communities that APS serves and 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 the catastrophic wildfires in California. While we proactively take steps to mitigate wildfire risk in the areas of our electrical assets, wildfire risk is always present due to APS's expansive service territory. APS could be held liable for damages incurred as a result of wildfires if it was determined that they were caused by or enhanced due to APS's negligence. 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, and the construction of sufficient transmission capacity to support these facilities. 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 supply 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 suffer 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 2a 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 for 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.

The ownership and operation of power generation and transmission facilities on Indian lands could result in uncertainty related to continued leases, easements, and rights-of-way, which could have a significant impact on our business.

Four Corners and portions of certain APS transmission lines are located on Indian lands pursuant to leases, easements or other rights-of-way that are effective for specified periods. APS is unable to predict the final outcomes of pending and future approvals by the applicable sovereign governing bodies with respect to renewals of these leases, easements, and rights-of-way.

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 \$120.1 million (but not more than \$17.9 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 \$22.3 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 30% of employees eligible to retire by the end of 2027. 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.

COVID-19 could negatively affect our business.

COVID-19 is a continually developing situation around the globe that has led to economic disruption and volatility in the financial markets. The spread of COVID-19 and efforts to contain the virus and mitigate its public health effects, could decrease demand for energy, lower economic growth, impact our employees and contractors, cause disruptions in our supply chain, increase certain costs, further increase volatility in the capital markets (and result in increases in the cost of capital or an inability to access the capital markets or draw on available credit facilities), delay the completion of capital or other construction projects and other operations and maintenance activities, delay payments or increase uncollectable accounts, impact our ability to hire or retain qualified employees, or cause other unpredictable events, each of which could adversely affect our business, results of operations, cash flows or financial condition.

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 into 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. Declining interest rates decrease the discount rate, increase the 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 position, 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 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, during 2021 and 2022, 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, COVID-19 severely impacted global supply chains, 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 2022 fiscal year and that remain unresolved.

ITEM 2. PROPERTIES

Generation Facilities

APS's portfolio of owned generating facilities as of December 31, 2022 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 (d)	2		Gas	Load Following	1,088
West Phoenix	5		Gas	Load Following	887
Total Combined Cycle					1,975
Combustion Turbine:					
Ocotillo (e)	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 (f)	1		Solar	As Available	17
Hyder I (f)	1		Solar	As Available	17
Paloma (f)	1		Solar	As Available	17
Chino Valley	1		Solar	As Available	20
Gila Bend (f)	1		Solar	As Available	36
Hyder II (f)	1		Solar	As Available	14
Foothills (f)	1		Solar	As Available	38
Luke AFB	1		Solar	As Available	11
Desert Star (f)	1		Solar	As Available	10
Red Rock	1		Solar	As Available	44
APS Owned Distributed Energy Multiple facilities			Solar	As Available	36
					4
Total Solar					264
Total Capacity					6,340

- (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, 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) Redhawk generation capacity increased by 104 MW following the Advanced Gas Path upgrade installed on both units.
- (e) 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.
- (f) 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 January 3, 2023, APS's transmission facilities consist of approximately 5,828 pole miles of overhead lines and approximately 85 miles of underground lines, 5,768 miles of which are located in Arizona. APS's distribution facilities consist of approximately 11,276 miles of overhead lines and approximately 23,082 miles of underground primary cable (20,021 when excluding abandoned conductor), all of which are located in Arizona. APS also owns and maintains 469 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, 2022:

	Percent Owned (Weighted-Average)
Morgan — Pinnacle Peak System	64.7 %
Palo Verde — Rudd 500kV System	50.0 %
Round Valley System	50.0 %
ANPP 500kV System	33.4 %
Navajo Southern System	26.8 %
Four Corners Switchyards	61.9 %
Palo Verde — Yuma 500kV System	25.4 %
Phoenix — Mead System	17.1 %
Palo Verde — Morgan System	87.8 %
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 2023 Ten-Year Plan, APS projects it will develop 84 miles of new transmission lines over the next 10 years. Additionally, APS plans to upgrade 55 miles of existing transmission lines over the same horizon. The 2023 Ten-Year Plan includes a new 25-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. In addition, this new source will provide customers in the area greater access to a diverse mix of resources from around the region. The 2023 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, 2023, current positions and principal occupations for the past five years are as follows:

Name	Age	Position	Period
Jeffrey B. Guldner	57	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
		Executive Vice President, Public Policy of APS	2017-2018
		General Counsel of Pinnacle West and APS	2017-2018
Elizabeth A. Blankenship	51	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	44	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
Donna M. Easterly	58	Senior Vice President, Human Resources of APS	2020-Present
		Vice President, Human Resources and Ethics of APS	2017-2020
Jose L. Esparza	48	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	44	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
		General Manager, Transmission and Distribution Operations and Maintenance of APS	2017-2018
Adam C. Heflin	59	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	45	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	53	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	50	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

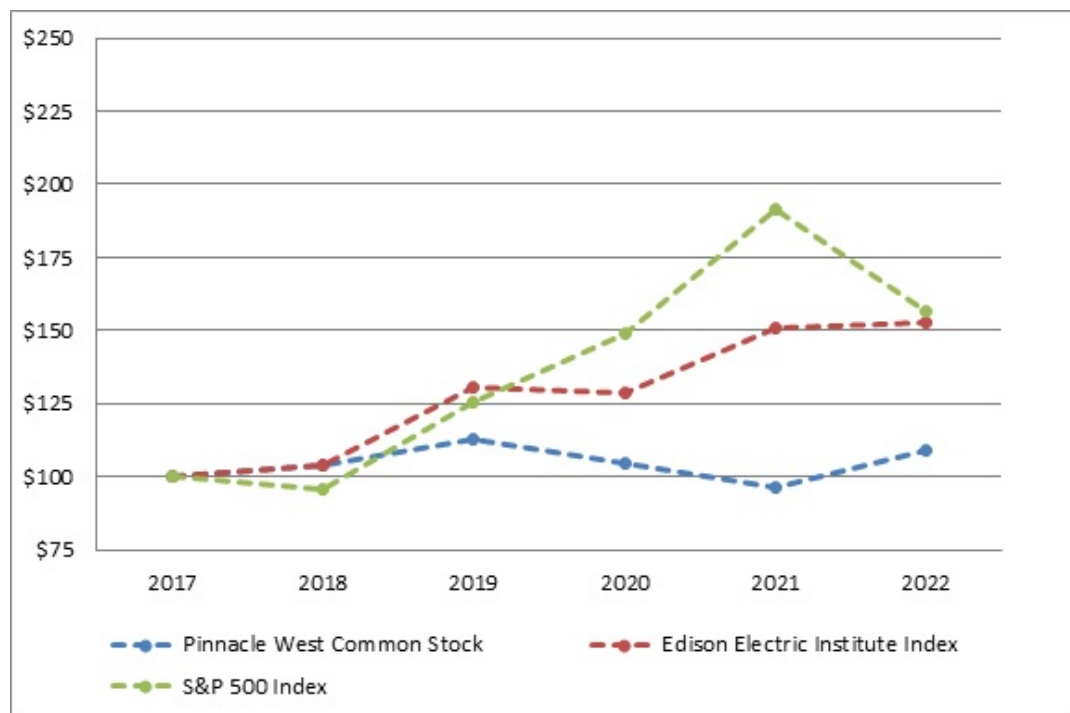
ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

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, 2023, Pinnacle West's common stock was held of record by approximately 15,182 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, 2022, 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, 2022, 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, 2017, in Pinnacle West's common stock and in each of the indices shown and that all of the dividends were reinvested.



	Years Ended December 31,					
<u>Company/Index</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>
Pinnacle West Common Stock	\$100	\$104	\$113	\$104	\$96	\$109
Edison Electric Institute Index	\$100	\$104	\$130	\$129	\$151	\$153
S&P 500 Index	\$100	\$96	\$126	\$149	\$192	\$156

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 2022 results with 2021 results. A comparison of the 2021 results with 2020 results can be found in the Annual Report on Form 10-K for the fiscal year ended December 31, 2021. 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 about \$23 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 1.3 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 southwest United States and the largest nuclear power plant in the United States.

Inflation

Overall inflation has grown by 9.5% in Phoenix in 2022, compared to 6.5% nationally; however, APS’s work with national and international companies has helped to partially reduce local cost escalation impacts on APS. The impacts from inflation have varied across separate categories of APS’s spending. Pricing increases across major categories have ranged from 8% to 10% for vendor services and up to 15% to 60% for equipment in 2022. APS has seen specific inflationary impacts in individual spend categories, as well as general inflationary pricing impacts on a broader set of spend categories. Some of the highest increases in 2022 as compared to 2021 have been in chemical costs and contract services.

Even prior to these increases, APS has focused on its customer affordability initiative, which has enabled APS to mitigate inflationary pressure. This initiative includes identifying efficiency opportunities through APS’s LEAN Sigma approach as well as other corporate decisions. For example, APS maintains its inventory to take advantage of lower pricing, when available, and to minimize supply chain delays that can increase the pricing due to expediting fees. Additionally, APS has proactively entered into long-term contracts to hedge against price volatility, which has allowed it to mitigate several procurement spend areas such as transformers.

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 the Company’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, available from 2024 through 2032. The Internal Revenue Service and U.S. Treasury are expected to issue regulations and other guidance which will provide additional details and clarifications regarding how the Company may be able to claim each of these credits.

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.

COVID-19

COVID-19 continues to be an evolving situation. Essential planned work and capital investments continued during the pandemic with priority given to support fire mitigation and summer storm efforts, as well as heat-related outages. Raw material shortages, rising inflation, COVID-19 related work force disruptions and natural disasters continue to place increased pressure on the global supply chain. APS is experiencing some delays in finished materials and tight labor markets. To date, APS has not experienced labor or material supply chain shortages that have significantly impacted its ability to serve its customers’ needs. However, shortages are causing minor delays and shifting of work projects based on material availability. If APS continues to experience delays in materials, it could experience an increase in purchased power costs for summer generation needs. Such increased purchased power costs would be expected to be recoverable through the PSA. See Note 3 for additional information on the PSA. APS has measures in place to continually monitor and evaluate resource needs and supply chain adequacy but cannot predict whether there will be material supply chain shortages in the future.

While the total expected impact of COVID-19 on future sales is currently unknown, APS experienced higher electric residential sales and lower electric commercial and industrial sales from the outset of the pandemic through April 2021. Beginning in May 2021, electric sales from commercial and industrial customers increased to levels in line with pre-COVID-19 sales but residential sales continued to be higher than pre-COVID-19 sales. 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 Coronavirus Aid, Relief, and Economic Security (“CARES”) Act allowed 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, which was approximately \$18 million. As of December 31, 2022, we have paid this cash deferral in full.

Due to COVID-19, APS voluntarily suspended disconnections of customers for nonpayment beginning March 13, 2020 until December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021, and customers were automatically placed on eight-month payment arrangements if they had past due balances at the end of the disconnection period of \$75 or greater. APS voluntarily began waiving late payment fees of its customers on March 13, 2020. Effective February 1, 2023, late payment fees for residential customers were reinstated, and late payment fees for commercial and industrial customers were reinstated effective May 1, 2022. See Note 3 for additional information regarding the Summer Disconnection Moratorium.

More detailed discussion of the impacts and future uncertainties related to COVID-19 can be found throughout this Management's Discussion and Analysis of Financial Condition and Results of Operations and the Combined Notes to Pinnacle West's and APS's financial statements that appear in Part II, Item 8 of this report and "Risk Factors" in Part I, Item 1A of this report.

Strategic Overview

Our strategy is to deliver shareholder value by creating a sustainable energy future for Arizona by serving our customers with clean, reliable, and affordable energy.

Clean Energy Commitment

We are committed to doing our part to make the future clean and carbon-free. 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 through providing clean, affordable, and reliable energy. We can accomplish our visions through collaboration with customers, communities, employees, policymakers, shareholders, and other stakeholders. Our clean energy goal 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 goals consist of three parts:

- a 2050 goal to provide 100% clean, carbon-free electricity;
- a 2030 target of achieving a resource mix that is 65% clean energy, with 45% of the generation portfolio coming from renewable energy; and
- a commitment to end APS's use of coal-fired generation by 2031.

APS's ability to successfully execute its clean energy commitment is dependent upon a number of important external factors, some of which include a supportive regulatory environment, sales and customer growth, development of clean energy technologies and continued access to capital markets.

2050 Goal: 100% Clean, Carbon-Free Electricity. Achieving a fully clean, carbon-free energy mix by 2050 is our aspiration. The 2050 goal will involve new thinking and depends on improved and new technologies.

2030 Goal: 65% Clean Energy. APS has an energy mix that is already 50% clean with existing plans to add more renewables and energy storage before 2025. 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 sources 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 100% clean, carbon-free energy mix by 2050.

2031 Goal: End APS's Use of Coal-Fired Generation. The commitment to end APS's use of coal-fired generation by 2031 will require APS to cease use of 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 a total reduction of carbon emissions of 33% since 2005. In addition, APS has committed to end the use of coal at its remaining Cholla units by 2025.

APS understands that the transition away from coal-fired power plants toward a clean energy future will pose unique economic challenges for the communities around these plants. We worked collaboratively with stakeholders and leaders of the Navajo Nation to consider the impacts of ceasing operation of APS coal-fired power plants on the communities surrounding those facilities to propose a comprehensive Coal Community Transition ("CCT") plan. The proposed framework provided substantial financial and economic development support to build new economic opportunities and addresses a transition strategy for plant employees. We are committed to continuing our long-running partnership with the Navajo Nation in other areas as well, including expanding electrification and developing tribal renewable energy projects. Our proposed CCT plan supported the Navajo Nation, where Four Corners is located, the communities surrounding the Cholla Power Plant and the Hopi Tribe, which was impacted by closure of the Navajo Plant. On November 2, 2021, the ACC approved an amended 2019 Rate Case ROO that will require (i) equal payments over a three-year period that total \$10 million to the Navajo Nation, (ii) a \$1 million one-time payment to the Hopi Tribe within 60 days of the 2019 Rate Case decision, (iii) a \$500,000 one-time payment to the Navajo County communities within 60 days of the 2019 Rate Case decision, (iv) up to \$1.25 million for electrification of homes and businesses on the Hopi reservation, and (v) up to \$1.25 million for the electrification of homes and businesses on the Navajo Nation reservation. The payments and expenditures are attributable to the future closures of Four Corners and Cholla, along with the prior closure of the Navajo Plant. All ordered payments and expenditures would be recoverable through rates. See Note 3 for a discussion of the CCT plan.

Consistent with the 2019 Rate Case decision, as of April 2022, APS has completed the following payments that will be recoverable through rates related to the CCT: (i) \$3.33 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) \$0.5 million to the Navajo Nation for CCT; (ii) \$1.1 million to the Navajo County Communities for CCT and economic development; and (iii) \$1.25 million to the Hopi Tribe for CCT and economic development. The ACC 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.

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. APS cannot predict if the ACC will take any further action on this matter.

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 beginning in 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. APS anticipates that it will elect not to begin seasonal operation in November 2023, unless market conditions change.

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 energy and positive customer outcomes and includes: (a) competitive solicitations to procure 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, which is already strengthened by Palo Verde, the nation's largest carbon-free, clean energy resource, that 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 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. See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Current and Future Resources — Renewable Energy Standard — Renewable Energy Portfolio" in Item 1 for details regarding APS's renewable energy resources.

In September 2019, APS issued an RFP that requested up to 250 MW of wind resources to be in service as soon as possible, but no later than 2022. As a result of this RFP, APS executed a 200 MW PPA for a wind resource that went into service in January 2022. In December 2020, APS issued two additional RFPs: (i) a battery storage RFP for projects to be located at two AZ Sun sites; and (ii) an all source RFP that solicited resources to meet our clean energy needs and capacity to maintain system reliability, and that was later amended to include a request for 150 MW of solar resources to be developed on APS property and owned by APS. As a result of the December 2020 RFPs, APS executed two solar plus storage PPAs totaling 275 combined MW, a PPA for a 238 MW wind resource, two energy storage PPAs for a combined 300 MW, extended an existing natural gas tolling agreement and also executed an engineering,

procurement, and construction contract in November 2021 for a 150 MW solar resource to be owned by APS and in service in early 2023.

In May 2022, APS issued an RFP to address resource needs for 2025 and beyond. The 2022 RFP solicits competitive proposals for approximately 1,000 MW to 1,500 MW of resources, including up to 600 MW to 800 MW of renewable resources to meet the needs of 2025 and 2026 while considering resources that can be online as late as 2027. The 2022 RFP stopped accepting bids on July 15, 2022, and APS sent notifications to shortlisted bidders on September 23, 2022. As a result of the 2022 RFP, and as of December 31, 2022, APS has signed a PPA for 300 MW of solar plus energy storage resources and a PPA for 216 MW of wind resources. Once it secures those important resources and closes out the 2022 RFP, APS intends to issue its next RFP to address future resource needs.

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.

In 2018, APS issued RFP for approximately 106 MW of energy storage to be located at up to five of its AZ Sun sites. Based upon its evaluation of the RFP responses, APS decided to expand the initial phase of battery deployment to 141 MW by adding a sixth AZ Sun site. These battery storage facilities are currently expected to be in service during the first quarter of 2023. On August 2, 2021, APS executed a contract for an additional 60 MW of utility-owned energy storage to be located on APS's AZ Sun sites. This contract, with a 2023 in-service date, will complete the addition of storage on current APS-owned utility-scale solar facilities.

Additionally, in February 2019, APS signed two 20-year PPAs for energy storage totaling 150 MW. These PPAs were subject to ACC approval in order to allow for cost recovery through the PSA. APS received the requested ACC approval on January 12, 2021, and service under the agreements is expected to begin in 2023.

As a result of its December 2020 RFPs, APS executed four 20-year PPAs for resources that include energy storage: (a) two PPAs for standalone energy storage resources totaling 300 MW; and (b) two PPAs for solar plus energy storage resources totaling 275 MW. The PPAs are also subject to ACC approval to enable cost recovery through the PSA. APS received the requested ACC approval for three out of four of the projects on December 16, 2021 and on April 13, 2022 for the remaining project. Service under the agreements is expected to begin in 2023 and 2024.

Following the 2022 RFP, as of January 2023, APS has executed a 20-year PPA for solar plus storage resources totaling 300 MW. The PPA is subject to ACC approval to enable cost recovery through the PSA, which was requested in December 2022 and approved in February 2023. Service under this agreement is expected to begin in 2025.

APS currently plans to install more than 1,200 MW of energy storage by 2025, including the energy storage projects under PPAs and AZ Sun retrofits described above. The remaining energy storage is expected to be made up of 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, 2021. Agreements for the development and completion of future resources are subject to various conditions.

	Net Capacity in Operation (MW)	Net Capacity Planned / Under Development (MW)
APS Owned Energy Storage	—	201
PPAs Energy Storage	—	1,025
Residential Energy Storage	19(a)	7
Total Energy Storage Portfolio	19	1,233

(a) This includes 18.5 MW of APS customer-owned batteries and 0.2 MW of APS-owned residential batteries.

Palo Verde. Palo Verde, the nation's largest carbon-free, clean energy resource, 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 southwest 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.

Affordable

Building upon existing cost management efforts, APS launched a customer affordability initiative 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 to assist in mitigating cost increases, increasing employee retention, and improving customer satisfaction.

Participation in the EIM 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 EIM 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 continues to evaluate opportunities that benefit our customers and is exploring opportunities to move to a day-ahead market with the expectation of reliably achieving incrementally greater cost savings and using the region's increasing renewable resources more efficiently. As part of that effort, APS is exploring several options. APS is in discussions with the current EIM operator, the CAISO, the Western Resource Adequacy Program, the Western Markets Exploratory Group, and the Southwest Power Pool. Each of these explorations also involve other entities and are being undertaken to evaluate the feasibility and cost/benefit of creating a voluntary day-ahead market.

Reliable

While our energy mix evolves, the 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. Our advanced distribution management system allows operators to locate outages, control line devices remotely and helps them coordinate more closely with field crews to safely maintain an increasingly dynamic grid. The system also integrates a new meter data management system that increases grid visibility and gives customers access to more of their energy usage data.

Wildfire safety remains a critical focus for APS and other utilities. We 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. These programs contribute to customer reliability, responsible forest management and safe communities.

The new units at our modernized Ocotillo Power Plant provide cleaner-running and more efficient units. They 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. APS continues to evaluate options to meet growing energy demand and ensure grid reliability, including through upgrades to and/or modernization of additional existing gas facilities.

In October of 2021, APS announced plans to evaluate regional market solutions as part of the informal Western Markets Exploratory Group (“WMEG”). As part 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’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 walkdowns 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.

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 from the fourth quartile to the first quartile of its peer set comprised of large investor-owned utilities. APS made progress on that front in 2022.

As previously disclosed, APS’s JDP Residential rankings for overall customer satisfaction rating improved in 2020 and 2021. That improvement trend continued with the JDP Residential 2022 year-end results. Compared to 2021, APS made quartile gains in every single driver of residential customer satisfaction, firmly lifting APS into the second quartile nationally. Consequently, overall residential satisfaction is now above industry benchmarks when compared to APS’s large investor-owned peers. APS’s strongest performing drivers for the year were Customer Care (phone and digital), Power Quality and Reliability, Corporate Citizenship, and Billing & Payment. Additionally, the JDP Business 2022 full-year results place APS in the top – or first – quartile of utilities nationally for business customers. As a

result, APS is among the most improved utilities in the nation for both residential and business customer satisfaction.

In mid-2021, APS initiated an organization-wide customer experience strategy council designed to further drive a customer-oriented culture and improve customer satisfaction. Through this and other on-going customer-centric initiatives, APS has embraced increased empathy training for care center associates and adopted more flexible payment arrangements for customers. Numerous customer web-based enhancements also were implemented, including streamlined navigation and Spanish language transaction capabilities on [aps.com](#); an enhanced online power outage center; and enrollment of more than 1 million customers for outage email and text notifications. Additionally, APS launched a broad-reaching multi-channel communications campaign focused on messages that matter most to APS's customers – reliability, energy-efficiency, financial assistance, the environment, and programs that enable customers to design their own personalized energy experience.

APS offers assistance programs that provide discounts to qualified limited-income customers, as well as programs to help customers stay current on their bills. And, to ensure our most vulnerable customers are connected to these programs, we train and work with more than 100 community action agencies. APS's Energy Support program gives qualified limited-income customers a 25% discount on their bill each month. Additionally, qualified customers experiencing an unplanned major expense or an unexpected reduction in income can receive up to \$800 a year to cover current or past due APS bills through the Crisis Bill Assistance program. Making customers aware of the assistance programs and resources available to them is a top priority for APS, and we have significantly increased the level of marketing and customer outreach through various campaigns and communication channels. As of December 31, 2022, approximately 60,000 customers received an aggregate of about \$29.6 million in bill assistance from various sources, with the largest amount coming from the Arizona Department of Economic Security's Emergency Rental Assistance Program. This assistance is on top of the approximately \$33 million of discounts provided to eligible customers through the APS Energy Support Program.

A consumer working group and a customer advisory board were formed in 2020 – the former made up of stakeholders and advocates representing various customer interests, and the latter comprised of a cross-section of customers. APS meets monthly with the consumer working group to obtain feedback on customer-related initiatives. Topics in 2022 ranged from TOU implementation, bill redesign, [aps.com](#), customer assistance and customer care center performance. APS also met with the customer advisory board in 2022 to keep apprised of customer needs, wants and perspectives on a variety of topics, including rate plan selection, billing and payment alerts, value for price insights and outage experience. The customer advisory board's input helped shape customer communications, as well as our thinking on related program development. In September 2022, APS completed the transition to new 4 p.m. to 7 p.m. on-peak TOU hours. More than one million residential customer meters were reprogrammed to the new on-peak hours.

Developing Clean Energy Technologies

Electric Vehicles

APS is making electric vehicle charging more accessible for its customers and helping Arizona businesses, schools and governments electrify their fleets. In 2021, APS continued its expansion of its Take Charge AZ Pilot Program. As of December 31, 2022, APS had installed 668 Level 2 ("L2") charging ports at customer locations, with more stations expected to be added through 2023. The program provides

charging equipment, installation, and maintenance to business customers, government agencies, non-profits, and multifamily housing communities. In addition to the L2 charging stations, APS has deployed DC fast charging (“DCFC”) stations that are owned and operated by APS at five locations in Arizona. The first location opened for public use in March 2022 in Show Low, Arizona. The other four projects in Sedona, Prescott, Globe, and Payson were energized by the end of 2022. Each location features 2-150 kilowatt and 2-350 kilowatt DCFC ports. Charging at these stations will be accessible through the Electrify America charging network. APS has a goal to reach 450,000 light-duty electric vehicles in its service territory by 2030.

Additionally, as part of APS’s DSM Plan, APS has launched an Electric Vehicle Charging Demand Management Pilot Program to proactively address the growing electric demand from electric vehicle charging as electric vehicles become more widely adopted. This program includes the APS SmartCharge data gathering program, a \$250 residential electric vehicle smart charger rebate for qualifying electric vehicle chargers, 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 2023 DSM Plan on November 30, 2022, which proposes two new programs, an expanded residential EV Managed Charging Program and a Commercial Make-Ready Program. The Commercial Make-Ready Program is intended to help reduce some of the high upfront cost for our customers installing DCFC stations, and enables APS to deploy effective load management strategies at these commercial sites.

The ACC ordered certain public service corporations, including APS, to develop a long-term, comprehensive statewide transportation electrification plan (“TE Plan”) for Arizona. The statewide TE Plan is intended to provide a roadmap for transportation electrification in Arizona, focused on realizing the associated air quality and economic development benefits for all residents in the state along with understanding the impact of electric vehicle charging on the grid. APS actively participated in the development of that plan, which was approved by the ACC in December 2021. In the decision, the ACC also ordered APS and another large Arizona electric public service corporation to each develop and submit for ACC approval their own TE Plans and corresponding budget for 2023. Accordingly, APS met its compliance obligation and filed both a 2023 TE Plan on June 1, 2022 and a supplemental TE Plan on November 30, 2022. APS will file its required TE progress reports on March 15 and September 15, 2023, along with a 2024 TE Plan later this year.

Hydrogen Production

APS, in partnership with Idaho National Laboratory (“INL”), Energy Harbor Corporation (“Energy Harbor”), and Xcel Energy Incorporated (“Xcel”), was chosen by the DOE’s Office of Nuclear Energy to participate in a series of hydrogen production projects with the goal to improve the long-term economic competitiveness of the nuclear power industry. The multi-phase projects began in 2020 with a series of small-scale hydrogen production demonstration projects led by Energy Harbor and Xcel, as well as a technical and economic assessment performed by INL of using electricity generated at Palo Verde to produce hydrogen.

Based on the experience from Palo Verde’s utility partners’ small scale demonstration projects and from the Palo Verde-specific technical and economic assessment performed by INL, in April 2021, PNW Hydrogen LLC (“PNW Hydrogen”), a newly formed subsidiary of Pinnacle West, applied for DOE funding for a larger scale hydrogen production demonstration project using electricity sourced from Palo Verde. On October 7, 2021, PNW Hydrogen was notified that DOE’s Office of Energy Efficiency & Renewable Energy and Office of Nuclear Energy had selected PNW Hydrogen’s application for an award of \$20 million in federal funding to support the hydrogen production demonstration project, subject to

negotiation and execution of a definitive Cooperative Agreement funding instrument between PNW Hydrogen and DOE. PNW Hydrogen continues to work through negotiations with DOE, while also investigating how best to coordinate its efforts with the Southwest Clean Hydrogen Innovation Network (“SHINe”) regional hub on development opportunities.

SHINe Regional Hub. The Infrastructure Investment and Jobs Act (“IIJA”), also known as the Bipartisan Infrastructure Bill, was signed into law on November 15, 2021. Among other things, the IIJA included money for regional clean hydrogen hubs, and on February 15, 2022, the Department of Energy DOE announced a Request for Information to collect feedback from stakeholders to inform the implementation and design of the regional hubs.

On May 12, 2022, APS, along with three other Arizona energy providers and the State’s three public universities announced the formation of a new, interdisciplinary coalition, called the Arizona Center for a Carbon Neutral Economy (“AzCaNE”), with the goal of attaining a carbon neutral economy in Arizona. AzCaNE’s first action was to pursue the creation of 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 current efforts.

On September 22, 2022, the DOE opened applications for the up to \$7 billion program to create six to ten regional clean hydrogen hubs across the country. Concept papers for each regional hub were due by November 7, 2022, and AzCaNE submitted a concept paper for the SHINe regional hub. On December 27, 2022, the SHINe regional hub was one of thirty-three regional hubs encouraged to submit a full application by the DOE. Full applications are due by April 7, 2023.

Carbon Capture

Carbon capture technologies can isolate CO₂ 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. Carbon capture 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.

Environmental, Social, and Governance (“ESG”) Practices

Pinnacle West has been integrating ESG practices into its core work for almost 30 years. As a business strategy, we seek solutions that provide “shared value,” meaning solutions that address societal and environmental challenges in a way that also delivers business value. Our commitment extends beyond implementing sustainability practices; we are dedicated to working with our stakeholders to identify and address the sustainability issues that we are uniquely positioned to impact through our business. In 2020, in support of our clean energy commitment and the growing focus on ESG within our organization, we increased our efforts by dedicating a new Sustainability Department at Pinnacle West to integrating ESG best practices into the everyday work of the Company.

As a first step, the Company 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, Integral Shared Value, 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 Integral PSIs provide the foundation for informing our strategic direction, creating a framework for incorporating best practices and driving enterprise-wide alignment and accountability. In 2021, the Company engaged EPRI for the second phase of this work, focused on benchmarking best practices within these four Integral Shared Value PSIs. We utilized the benchmarking information to identify opportunities for further improvement in our ESG performance.

In 2021, the Company established a Social Issues Committee Framework. The goal of the framework is to provide a process for considering emergent social issues, and for determining whether or how best to engage. The committee’s responsibility is to determine, using a set of principles grounded in the APS Promise and the PSIs, whether engagement on specific emergent social issues is appropriate and, if so, how best to engage.

The Company also finalized an ESG Strategic Framework to guide our work. The framework is based upon three foundational pillars: ESG Policy Advocacy (we advocate for policy that supports our clean energy goals); Driving Performance (improving our ESG performance in the most important areas, including our PSIs); and effectively communicating and amplifying our ESG story to our various stakeholders, including investors, customers, employees and beyond. Throughout 2022, the ESG Strategic Framework has guided our ESG activities allowing the Sustainability Department to prioritize projects and collaborate with our teams in the Company. Also in 2022, the Company developed an ESG Narrative, aligned to the APS Promise, to guide the Company’s communications strategy internally and externally to customers to effectively share APS’s sustainability story.

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 are:

- a test year comprised of 12 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:

	<u>Capital Structure</u>	<u>Cost of Capital</u>
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 and collect costs through base rates,
 - eliminate the Lost Fixed Cost Recovery mechanism and collect costs through base rates and the Demand Side Management Adjustment Charge ("DSMAC"),
 - maintain as inactive the Tax Expense Adjustor Mechanism,
 - maintain the Transmission Cost Adjustment mechanism,
 - modify the performance incentive in the DSMAC, and
 - modify the Renewable Energy Adjustment Charge 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 to reflect used and useful projects that will be placed into service prior to July 1, 2023.

APS requested that the increase become effective December 1, 2023. The hearing for this rate case is currently scheduled to begin in August 2023. APS cannot predict the outcome of its request.

2019 Retail Rate Case

On October 31, 2019, APS filed an application with the ACC (the "2019 Rate Case") seeking an increase in annual retail base rates. On August 2, 2021, the 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. See Note 3 for information regarding the 2019 Rate Case ROO.

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%, (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, results in a total annual revenue decrease for APS of \$4.8 million, excluding temporary CCT payments and expenditures. On November 2, 2021, the ACC approved the 2019 Rate Case ROO, as amended. 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. 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. The Court took the matter under advisement and will issue its decision in due course. APS cannot predict the outcome of this proceeding.

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 and will be continuing to explore whether penalties or rebates would be owed to certain customers. APS completed the implementation of the new on-peak hours for residential customers before the September 1, 2022 deadline. APS cannot predict if the ACC will take any further action on this matter.

Additionally, consistent with the 2019 Rate Case decision, as of April 2022, APS has completed the following payments that will be recoverable through rates related to the CCT: (i) \$3.33 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) \$0.5 million to the Navajo Nation for CCT; (ii) \$1.1 million to the Navajo County Communities for CCT and economic development; and (iii) \$1.25 million to the Hopi Tribe for CCT and economic development. The ACC 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.

See Note 3 for information regarding additional regulatory matters.

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. The Court took the matter under advisement and will issue its decision in due course. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of December 31, 2022. If the 2019 Rate Case decision to disallow \$215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately \$154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See Note 3 for additional information regarding the Four Corners SCR cost recovery.

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

Bright Canyon Energy. On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE's strategy is to develop, own, operate and acquire energy infrastructure in a manner that leverages the Company's core expertise in the electric energy industry. As of December 31, 2022, BCE had total assets of approximately \$115.3 million.

In 2014, BCE formed a 50/50 joint venture with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. The joint venture, named 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.

On December 20, 2019, BCE acquired minority ownership positions in two wind farms under development 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 and Nobles 2 achieved commercial operation in December 2020. Both wind farms deliver power under long-term PPAs. BCE indirectly owns 9.9% of Clear Creek and 5.1% of Nobles 2.

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 and filed a complaint with FERC on May 21, 2021, which was denied on September 9, 2022. Subsequently, Tenaska Clear Creek Wind, LLC filed with FERC a request for rehearing and a motion for stay of the September 9, 2022 order. On October 7, 2022, the request for rehearing was denied by FERC. FERC has not ruled on the motion for stay. Clear Creek has filed a Petition for Review with the U.S. Court of Appeals and Motion for Stay Pending Appeal, both of which are still pending.

Tenaska Clear Creek Wind, LLC filed a second complaint with FERC on May 25, 2022, alleging that the wind farm was being curtailed in a discriminatory manner. The May 25, 2022 Complaint was denied by FERC on December 15, 2022 and Tenaska Clear Creek Wind, LLC requested Rehearing of the denial on January 13, 2023.

Due to the disputed system upgrades and the related curtailment, 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. These energy curtailments are expected to persist, unless and until system upgrades are implemented to alleviate the present transmission system congestion, or the disputes are determined in favor of, or settled in a manner favorable to, Tenaska Clear Creek Wind, LLC. As such, during the fourth quarter of 2022, due to these on-going disputes, cost allocation uncertainties, and no probable favorable resolution, BCE determined its equity method investment was fully impaired. Prior to the impairment, the investment had a carrying value of \$17.1 million, which has been 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 has started construction on a microgrid facility in Los Alamitos, California featuring 31 MW of solar, 20 MW of battery storage, and 3 MW of backup generators. Supported by a long-term power purchase agreement with San Diego Gas and Electric Company, Los Alamitos will supply 20 MW of solar and battery storage capacity to the Southern California grid and provide resilient backup power in the event of a grid emergency to the Army and California National Guard at Joint Forces Training Base Los Alamitos. The Los Alamitos project is scheduled to achieve commercial operation in third-quarter 2023. See Note 6 regarding a credit agreement entered into by BCE to finance capital expenditures and related costs for this microgrid project.

BCE and Ameresco, Inc. jointly own 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.

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 committed to a \$25 million investment in the Energy Impact Partners fund, which is an organization that focuses on fostering innovation and supporting the transformation of the utility industry. The investment will be made by El Dorado as investments are selected by the Energy Impact Partners fund. As of December 31, 2022, El Dorado has contributed approximately \$12.5 million to the Energy Impact Partners fund. Additionally, El Dorado committed to a \$25 million investment in AZ-VC (formerly the invasionAZ Fund), which 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 the State of Arizona, or based in other jurisdictions and having existing or potential strategic or economic ties to companies or other interests in the State of Arizona. As of December 31, 2022, El Dorado has contributed approximately \$2.6 million to AZ-VC. The remainder of the investment will be contributed by El Dorado as investments are selected by AZ-VC.

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 2020 through 2022, retail electric revenues comprised approximately 92% of our total operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, distributed energy additions, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery mechanisms. These revenue transactions are affected by the availability of excess generation or other energy resources and wholesale market conditions, including competition, demand, and prices.

Actual and Projected Customer and Sales Growth. Retail customers in APS's service territory increased 2.1% for the year ended December 31, 2022, compared with the prior-year period. For the three years through 2022, APS's customer growth averaged 2.2% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2023 and the average annual growth to be in the range of 1.5% to 2.5% through 2025 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 2.4% for the year ended December 31, 2022, compared with the prior-year period. While steady customer growth was offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives, the main drivers of positive sales for this period were a strong improvement in sales to commercial and industrial customers and the ramp-up of new data center customers.

For the three years through 2022, annual retail electricity sales growth averaged 2.5%, adjusted to exclude the effects of weather variations. Due to the expected rapid 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 3.5% to 5.5% for 2023 and that average annual growth will be in the range of 4.5% to 6.5% through 2025, including the effects of customer conservation, energy efficiency, and distributed renewable generation initiatives, but excluding the effects of weather variations. This projected sales growth range includes the impacts of several large data centers and new large manufacturing facilities, which are expected to contribute to average annual growth in the range of 3.5% to 5.5% through 2025.

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, and responses to retail price changes. 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 10.2% of the assessed value for 2022, 10.7% for 2021 and 10.8% for 2020. Property taxes decreased in 2022 due to recent legislative changes reducing both property tax assessment ratios and rates in Arizona. As we add new generating units and continue with improvements and expansions to our existing generation, transmission, and distribution facilities in future years, we anticipate property taxes may increase, though these increases will continue to be partially offset by the impacts of the recent legislative changes noted above.

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. On December 22, 2017, the Tax Cuts and Jobs Act (the “Tax Act”) was enacted and was generally effective on January 1, 2018. Changes impacting the Company include a reduction in the corporate tax rate to 21%, revisions to the rules related to tax bonus depreciation, limitations on interest deductibility and an associated exception for certain public utilities, and requirements that certain excess deferred tax amounts of regulated utilities be normalized. See Note 4 for details of the impacts on the Company as of December 31, 2022. In APS’s 2017 Rate Case Decision, the ACC approved the TEAM, which was being used to pass through the income tax effects to retail customers of the Tax Act. As part of the 2019 Rate Case (defined above), all impacts of the Tax Act were removed from the TEAM and incorporated into APS’s base rates. The TEAM was retained to address potential changes in tax law that may be enacted prior to a decision in APS’s next rate case. See Note 3 for details of the TEAM.

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 in commercial operation.

RESULTS OF OPERATIONS

Pinnacle West's only 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.

Operating Results – 2022 compared with 2021

Our consolidated net income attributable to common shareholders for the year ended December 31, 2022, was \$484 million, compared with \$619 million for the prior year. The results reflect a decrease of approximately \$114 million for the regulated electricity segment, which include higher depreciation and amortization expense primarily due to the absence of the Ocotillo modernization project and the Four Corners SCR project regulatory deferrals that ended upon the 2019 Rate Case effective date (see Note 3), increased plant assets and updated depreciation rates. In addition, the results reflect lower revenue driven by the LFCR alternative revenue treatment and higher operations and maintenance expense. These negative factors were partially offset by higher revenue driven by the effects of weather, customer usage and growth, increased transmission revenue and lower income taxes.

The following table presents net income attributable to common shareholders by business segment compared with the prior year:

	Year Ended December 31,		
	2022	2021	Net change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	\$ 2,690	\$ 2,645	\$ 45
Operations and maintenance	(983)	(951)	(32)
Depreciation and amortization	(753)	(651)	(102)
Taxes other than income taxes	(220)	(235)	15
Pension and other postretirement non-service credits — net	98	113	(15)
All other income and expenses, net	23	61	(38)
Interest charges, net of allowance for borrowed funds used during construction	(255)	(233)	(22)
Income taxes (Note 4)	(75)	(110)	35
Less income related to noncontrolling interests (Note 17)	(17)	(17)	—
Regulated electricity segment income	508	622	(114)
All other	(24)	(3)	(21)
Net Income Attributable to Common Shareholders	\$ 484	\$ 619	\$ (135)

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were \$45 million higher for the year ended December 31, 2022, 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)		
Lower refunds in the current year related to the Tax Act (Note 3)	\$ 141	\$ —	\$ 141
Effects of weather	77	19	58
Higher retail revenue due to changes in customer usage patterns and customer growth, partially offset by the impacts of energy efficiency and distributed generation	46	23	23
Higher transmission revenues (Note 3)	14	—	14
Higher renewable energy regulatory surcharges, partially offset by operations and maintenance costs	18	9	9
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	425	426	(1)
Lost fixed cost recovery (Note 3)	(54)	—	(54)
Impact of new retail base rates from 2019 Rate Case effective December 1, 2021	(147)	—	(147)
Miscellaneous items, net	2	—	2
Total	\$ 522	\$ 477	\$ 45

Operations and maintenance. Operations and maintenance expenses increased \$32 million for the year ended December 31, 2022, compared with the prior-year period primarily because of:

- an increase of \$14 million primarily related to a decreased recovery from contributions of administrative and general costs from Palo Verde owners and increased operating costs;
- an increase of \$10 million primarily related to strategic planning consulting costs;
- an increase of \$6 million for costs related to transmission, distribution and customer service;
- an increase of \$6 million primarily related to costs for renewable energy and similar regulatory programs, which are partially offset in operating revenues and purchased power;
- a decrease of \$12 million in non-nuclear generation costs primarily due to lower planned outages and partially offset by higher operating costs; and
- an increase of \$8 million for corporate resources and other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were \$102 million higher for the year ended December 31, 2022, compared with the prior-year period primarily due to \$55 million for the Ocotillo modernization project and the Four Corners SCR project regulatory deferrals recorded in the prior year period that ended upon the 2019 Rate Case effective date and the related 2022 regulatory deferral amortization, and \$47 million related to increased plant in service and updated depreciation rates.

Taxes other than income taxes. Taxes other than income taxes were \$15 million lower for the year ended December 31, 2022, compared with the prior-year period primarily due to the impacts of recent legislative changes reducing both property tax assessment ratios and rates in Arizona and property tax deferrals that ended upon the 2019 Rate Case effective date and the related 2022 property tax deferral amortization.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were \$15 million lower for the year ended December 31, 2022, compared to the prior-year period primarily due to actual market returns being lower than estimated returns in 2021.

All other income and expenses, net. All other income and expenses, net were \$38 million lower for the year ended December 31, 2022, compared to the prior-year period primarily due to the Ocotillo modernization and Four Corners SCR debt deferrals that ended upon the 2019 Rate Case effective date.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction were \$22 million higher for the year ended December 31, 2022, compared to the prior-year period primarily due to higher debt balances and higher interest rates in the current period, partially offset by higher allowance for borrowed funds due to increased capital expenditures.

Income taxes. Income taxes were \$35 million lower for the year ended December 31, 2022, compared with the prior-year period primarily due to lower pre-tax net income, partially offset by a net operating loss carryback benefit that the Company recognized during the first quarter of 2021.

All Other. All other earnings were \$21 million lower for year ended December 31, 2022, compared with the prior-year period primarily due to the Clear Creek wind farm impairment write-off. See “BCE Matters” in Note 10 for additional details.

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, 2022, APS’s common equity ratio, as defined, was 50%. Its total shareholder equity was approximately \$6.9 billion, and total capitalization was approximately \$13.9 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately \$5.6 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.

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.

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, 2022, and 2021 (dollars in millions):

Pinnacle West Consolidated

	2022	2021
Net cash flow provided by operating activities	\$ 1,242	\$ 860
Net cash flow used for investing activities	(1,618)	(1,387)
Net cash flow provided by financing activities	371	477
Net decrease in cash and cash equivalents	<u>\$ (5)</u>	<u>\$ (50)</u>

Arizona Public Service Company

	2022	2021
Net cash flow provided by operating activities	\$ 1,230	\$ 865
Net cash flow used for investing activities	(1,549)	(1,391)
Net cash flow provided by financing activities	314	478
Net decrease in cash and cash equivalents	<u>\$ (5)</u>	<u>\$ (48)</u>

Operating Cash Flows

2022 Compared with 2021. Pinnacle West's consolidated net cash provided by operating activities was \$1,242 million in 2022 compared to \$860 million in 2021, an increase of \$382 million in net cash provided primarily due to \$542 million higher cash receipts from electric revenues, \$47 million lower payments for operations and maintenance costs, \$100 million lower pension contributions and \$79 million other changes in working capital, partially offset by \$321 million higher fuel and purchased power costs, \$47 million higher income taxes and \$18 million higher interest payments. The difference between APS's and Pinnacle West's net cash provided by operating activities primarily relates to APS's income tax cash payments to Pinnacle West in 2021.

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 112% funded as of January 1, 2023, and was 139% as of January 1, 2022. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We made contributions to our pension plan totaling \$0 million in 2022, \$100 million in 2021, and \$100 million in 2020. 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 2023, 2024 or 2025. Regarding contributions to our other postretirement benefit

plan, we did not make any contributions in 2022 or 2021 and do not expect to make any contributions in 2023, 2024 or 2025. The Company was reimbursed \$26 million in 2022, \$24 million in 2021, and \$26 million in 2020 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 106% funded as of December 31, 2022, and our postretirement benefit plans were 159% funded, as measured for GAAP purposes at December 31, 2022. 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

2022 Compared with 2021. Pinnacle West's consolidated net cash used for investing activities was \$1,618 million in 2022 compared to \$1,387 million in 2021, an increase of \$231 million in net cash used primarily related to increased capital expenditures and BCE investment activity.

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,		
	2023	2024	2025
APS			
Generation:			
Clean:			
Nuclear Generation	\$ 120	\$ 120	\$ 120
Renewables and Energy Storage Systems ("ESS") (a)	240	345	400
Other Generation (b)	265	245	245
Distribution	520	530	530
Transmission	260	300	300
Other (c)	265	260	255
Total APS	\$ 1,670	\$ 1,800	\$ 1,850

(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 BCE 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 improvements to existing fossil plants. 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

2022 Compared with 2021. Pinnacle West's consolidated net cash provided by financing activities was \$371 million in 2022 compared to \$477 million 2021, a decrease of \$106 million in net cash provided primarily due to \$150 million higher long-term debt repayments, a net decrease in short-term borrowings of \$74 million and higher dividend payments of \$9 million, partially offset by \$129 million in higher issuances of long-term debt.

APS's consolidated net cash provided by financing activities was \$314 million in 2022 compared to \$478 million in 2021, a decrease of \$164 million in net cash provided primarily due to a net decrease in short-term borrowings of \$232 million and higher dividend payments of \$9 million, partially offset by \$78 million in higher issuances of long-term debt.

Significant Financing Activities. On December 14, 2022, the Pinnacle West Board of Directors declared a dividend of \$0.865 per share of common stock, payable on March 1, 2023, to shareholders of record on February 1, 2023. During 2022, Pinnacle West increased its indicated annual dividend from \$3.40 per share to \$3.46 per share. For the year ended December 31, 2022, Pinnacle West's total dividends paid per share of common stock were \$3.42 per share, which resulted in dividend payments of \$379 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, 2022, the ratio was approximately 58% for Pinnacle West and 51% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could "cross-default" other debt. See further discussion of "cross-default" provisions below.

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

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

On December 17, 2020, the ACC issued a financing order that, subject to specified parameters and procedures, increased APS's long-term debt limit from \$5.9 billion to \$7.5 billion, and authorized 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). On December 15, 2022, the ACC issued a financing order 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, 2023, 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, 2022. 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.

CRITICAL ACCOUNTING POLICIES

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 Commission-ordered refunds to customers on regulatory liabilities. We had \$1,822 million of regulatory assets and \$2,333 million of regulatory liabilities on the Consolidated Balance Sheets at December 31, 2022. 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, 2022 reported pension assets and liabilities on the Consolidated Balance Sheets and our 2022 reported pension expense, after consideration of amounts capitalized or billed to electric plant participants, on the Consolidated Statements of Income (dollars in millions):

Actuarial Assumption (a)	Increase (Decrease)	
	Impact on Pension Plans	Impact on Pension Expense
Discount rate (b):		
Increase 1%	\$ (238)	\$ 3
Decrease 1%	279	13
EROA:		
Increase 1%	—	(27)
Decrease 1%	—	27

- (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, 2022, other postretirement benefit obligation on the Pinnacle West's Consolidated Balance Sheets and our 2022 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):

Actuarial Assumption (a)	Increase (Decrease)	
	Impact on Other Postretirement Benefit Plans	Impact on Other Postretirement Benefit Expense
Discount rate (b):		
Increase 1%	\$ (39)	\$ (3)
Decrease 1%	46	4
Healthcare cost trend rate (c):		
Increase 1%	43	8
Decrease 1%	(36)	(6)
EROA – pretax:		
Increase 1%	—	(7)
Decrease 1%	—	7

- (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, 2022 are described further in Note 11.

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 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, 2022, and 2021. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2022, and 2021 (dollars in millions):

Pinnacle West – Consolidated

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2022						
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		<u>\$ 341</u>		<u>\$ 664</u>		<u>\$ 7,180</u>
Fair value		<u>\$ 341</u>		<u>\$ 664</u>		<u>\$ 5,922</u>

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2021						
2022	0.18 %	\$ 292	0.78 %	\$ 150	—	\$ —
2023	—	—	—	—	—	—
2024	—	—	0.85 %	150	3.35 %	250
2025	—	—	—	—	1.99 %	800
2026	—	—	—	—	2.55 %	250
Years thereafter	—	—	0.22 %	36	3.87 %	5,480
Total		<u>\$ 292</u>		<u>\$ 336</u>		<u>\$ 6,780</u>
Fair value		<u>\$ 292</u>		<u>\$ 336</u>		<u>\$ 7,390</u>

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, 2022, and 2021. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2022, and 2021 (dollars in millions):

APS — Consolidated

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2022						
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		<u>\$ 325</u>		<u>\$ 163</u>		<u>\$ 6,680</u>
Fair value		<u>\$ 325</u>		<u>\$ 163</u>		<u>\$ 5,466</u>

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2021						
2022	0.18 %	\$ 279	—	\$ —	—	\$ —
2023	—	—	—	—	—	—
2024	—	—	—	—	3.35 %	250
2025	—	—	—	—	3.15 %	300
2026	—	—	—	—	2.55 %	250
Years thereafter	—	—	0.22 %	36	3.87 %	5,480
Total		<u>\$ 279</u>		<u>\$ 36</u>		<u>\$ 6,280</u>
Fair value		<u>\$ 279</u>		<u>\$ 36</u>		<u>\$ 6,898</u>

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, 2022	December 31, 2021
Mark-to-market of net positions at beginning of year	\$ 107	\$ (13)
Increase (decrease) in regulatory liability	(11)	120
Mark-to-market of net positions at end of year	<u>\$ 96</u>	<u>\$ 107</u>

The table below shows the fair value of maturities of our energy derivative contracts (dollars in millions) at December 31, 2022, 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	2023	2024	2025	2026	2027	Total Fair Value
Observable prices provided by other external sources	\$ 70	\$ 31	\$ —	\$ —	\$ —	\$ 101
Prices based on unobservable inputs	(14)	9	—	—	—	(5)
Total by maturity	<u>\$ 56</u>	<u>\$ 40</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 96</u>

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, 2022 Gain (Loss)		December 31, 2021 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	\$ 12	\$ (12)	\$ —	\$ —
Natural gas	55	(55)	50	(50)
Total	<u>\$ 67</u>	<u>\$ (67)</u>	<u>\$ 50</u>	<u>\$ (50)</u>

- (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**

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

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, 2022 and 2021, 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, 2022, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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, 2022, based on criteria established in Internal Control — Integrated Framework (2013) issued by COSO.

Basis for Opinions

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

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

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

on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Accounting — Impact of Rate Regulation on the Financial Statements — Refer to Notes 1 and 3 to the financial statements

Critical Audit Matter Description

Arizona Public Service Company ("APS"), which is a wholly-owned subsidiary of the Company, is subject to rate regulation by the Arizona Corporation Commission (the "ACC"), which has jurisdiction with respect to the rates charged by public service utilities in Arizona. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant and equipment; regulatory assets and liabilities; operating revenues; fuel and purchased power; operations and maintenance expense; and depreciation expense.

The ACC's rate-making policies are premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the ACC in the future will impact the accounting for regulated operations, including decisions about the amount of allowable deferred costs

and return on invested capital included in rates and any refunds that may be required. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the ACC will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment. If future recovery of regulatory assets ceases to be probable or a disallowance becomes probable, it would result in a charge to earnings.

We identified Regulatory Accounting, specifically the impact of rate regulation on the financial statements, as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory rate orders on the financial statements. Management judgments include continually assessing the likelihood of future recovery of regulatory assets and/or a disallowance of part of the cost of recently completed plant, by considering factors such as applicable regulatory environment changes, recent rate orders specific to APS and to other regulated entities in the same jurisdiction, and likelihood of success of legal appeals. 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 and legal bodies, 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 regulatory accounting 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; 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; and the implementation of new rates as ordered by the ACC.
- 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 read APS's 2022 rate application submitted to the ACC on October 28, 2022.
- 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. For certain regulatory assets or liabilities where management's assessment is based on precedents established by the ACC under similar circumstances and not specifically addressed in a regulatory order, we also obtained a letter from internal legal counsel regarding their assessment. 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.

- We evaluated management's assessment that the SCR plant investment is not probable of a partial disallowance and that the SCR deferred costs are probable of recovery. We read the Notice of Direct Appeal filed with the Arizona Court of Appeals and Petition for Special Action filed with the Arizona Supreme Court, read APS's opening brief submitted to the Arizona Court of Appeals, read the ACC's Answering Brief, read the Intervenor's' briefs, read APS's reply brief, and observed the Appeal Oral Arguments, reviewed the Company's internally prepared memo, and reviewed a legal letter from the Company's external counsel to assess the likelihood of recovery in future rates or of a future reduction in rates based on the ACC decision.

/s/ Deloitte & Touche LLP

Tempe, Arizona
February 27, 2023

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,		
	2022	2021	2020
OPERATING REVENUES (Note 2)	\$ 4,324,385	\$ 3,803,835	\$ 3,586,982
OPERATING EXPENSES			
Fuel and purchased power	1,629,343	1,152,551	993,419
Operations and maintenance	987,072	954,067	958,910
Depreciation and amortization	753,195	650,875	614,378
Taxes other than income taxes	220,370	234,639	224,835
Other expenses	2,494	6,393	7,288
Total	3,592,474	2,998,525	2,798,830
OPERATING INCOME	731,911	805,310	788,152
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	45,263	41,737	33,776
Pension and other postretirement non-service credits — net (Note 7)	98,487	112,541	56,341
Other income (Note 16)	7,916	45,100	56,703
Other expense (Note 16)	(52,385)	(25,396)	(57,776)
Total	99,281	173,982	89,044
INTEREST EXPENSE			
Interest charges	283,569	254,314	247,501
Allowance for borrowed funds used during construction (Note 1)	(28,030)	(21,052)	(18,530)
Total	255,539	233,262	228,971
INCOME BEFORE INCOME TAXES	575,653	746,030	648,225
INCOME TAXES (Note 4)	74,827	110,086	78,173
NET INCOME	500,826	635,944	570,052
Less: Net income attributable to noncontrolling interests (Note 17)	17,224	17,224	19,493
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	\$ 483,602	\$ 618,720	\$ 550,559
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	113,196	112,910	112,666
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	113,416	113,192	112,942
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Net income attributable to common shareholders — basic	\$ 4.27	\$ 5.48	\$ 4.89
Net income attributable to common shareholders — diluted	\$ 4.26	\$ 5.47	\$ 4.87

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,		
	2022	2021	2020
NET INCOME	\$ 500,826	\$ 635,944	\$ 570,052
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized gain (loss), net of tax benefit (expense) of \$(615), \$(378), and \$662	1,873	1,077	(2,089)
Reclassification of net realized gain, net of tax benefit (expense) of \$0, \$18, and \$(171) (Note 15)	—	18	592
Pension and other postretirement benefits activity, net of tax benefit (expense) of \$(7,078), \$(2,256), and \$1,371 (Note 7)	21,553	6,840	(4,203)
Total other comprehensive income (loss)	23,426	7,935	(5,700)
COMPREHENSIVE INCOME	524,252	643,879	564,352
Less: Comprehensive income attributable to noncontrolling interests	17,224	17,224	19,493
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	\$ 507,028	\$ 626,655	\$ 544,859

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

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

	December 31,	
	2022	2021
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	\$ 4,832	\$ 9,969
Customer and other receivables	453,209	391,923
Accrued unbilled revenues	164,764	133,980
Allowance for doubtful accounts (Note 2)	(23,778)	(25,354)
Materials and supplies (at average cost)	410,481	349,135
Fossil fuel (at average cost)	40,155	18,032
Income tax receivable (Note 4)	14,086	7,514
Assets from risk management activities (Note 15)	87,835	63,481
Deferred fuel and purchased power regulatory asset (Note 3)	460,561	388,148
Other regulatory assets (Note 3)	78,318	130,376
Other current assets	60,091	83,896
Total current assets	1,750,554	1,551,100
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 12 and 18)	1,073,410	1,294,757
Other special use funds (Notes 12 and 18)	347,231	358,410
Assets from risk management activities (Note 15)	44,394	46,908
Other assets	125,672	97,884
Total investments and other assets	1,590,707	1,797,959
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9)		
Plant in service and held for future use	22,452,146	21,688,661
Accumulated depreciation and amortization	(7,929,878)	(7,504,603)
Net	14,522,268	14,184,058
Construction work in progress	1,882,791	1,329,478
Palo Verde sale leaseback, net of accumulated depreciation of \$260,754 and \$256,884 (Note 17)	90,296	94,166
Intangible assets, net of accumulated amortization of \$817,961 and \$737,694	258,880	273,693
Nuclear fuel, net of accumulated amortization of \$126,157 and \$133,122	100,119	106,039
Total property, plant and equipment	16,854,354	15,987,434
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3 and 4)	1,283,221	1,192,987
Operating lease right-of-use assets (Note 8)	801,688	890,057
Assets for pension and other postretirement benefits (Note 7)	396,599	545,723
Other	46,282	37,962
Total deferred debits	2,527,790	2,666,729
TOTAL ASSETS	\$ 22,723,405	\$ 22,003,222

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

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

	December 31,	
	2022	2021
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	\$ 430,425	\$ 393,083
Accrued taxes	164,440	168,645
Accrued interest	61,217	57,332
Common dividends payable	97,895	95,988
Short-term borrowings (Note 5)	340,720	292,000
Current maturities of long-term debt (Note 6)	50,685	150,000
Customer deposits	41,769	42,293
Liabilities from risk management activities (Note 15)	37,697	4,373
Liabilities for asset retirements (Note 11)	12,232	4,473
Operating lease liabilities (Note 8)	105,210	100,443
Regulatory liabilities (Note 3)	271,575	296,271
Other current liabilities	148,276	151,968
Total current liabilities	1,762,141	1,756,869
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 6)	7,741,286	6,913,735
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	2,384,421	2,311,862
Regulatory liabilities (Notes 1, 3, 4 and 7)	2,061,776	2,499,213
Liabilities for asset retirements (Note 11)	785,530	762,909
Liabilities for pension benefits (Note 7)	116,286	152,865
Customer advances	422,103	257,151
Coal mine reclamation	179,255	174,616
Deferred investment tax credit	180,677	186,570
Unrecognized tax benefits (Note 4)	38,658	4,657
Operating lease liabilities (Note 8)	639,247	728,401
Other	252,149	232,914
Total deferred credits and other	7,060,102	7,311,158
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 113,247,189 and 113,014,528 issued at respective dates	2,724,740	2,702,743
Treasury stock at cost; 73,613 and 87,608 shares at respective dates	(5,005)	(6,401)
Total common stock	2,719,735	2,696,342
Retained earnings	3,360,347	3,264,719
Accumulated other comprehensive loss (Note 19)	(31,435)	(54,861)
Total shareholders' equity	6,048,647	5,906,200
Noncontrolling interests (Note 17)	111,229	115,260
Total equity	6,159,876	6,021,460
TOTAL LIABILITIES AND EQUITY	\$ 22,723,405	\$ 22,003,222

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,		
	2022	2021	2020
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	\$ 500,826	\$ 635,944	\$ 570,052
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	817,814	719,141	686,253
Deferred fuel and purchased power	(291,992)	(256,871)	(93,651)
Deferred fuel and purchased power amortization	219,579	44,557	(12,047)
Allowance for equity funds used during construction	(45,263)	(41,737)	(33,776)
Deferred income taxes	43,202	117,471	69,469
Deferred investment tax credit	(5,893)	(4,802)	(5,096)
Change in derivative instruments fair value	777	—	—
Stock compensation	15,942	18,460	18,292
Changes in current assets and liabilities:			
Customer and other receivables	(63,869)	(72,559)	(18,191)
Accrued unbilled revenues	(30,784)	(1,783)	(4,032)
Materials, supplies and fossil fuel	(83,469)	(32,870)	11,623
Income tax receivable	(6,572)	(722)	14,935
Other current assets	76,067	(22,720)	(30,640)
Accounts payable	90,076	20,267	(6,059)
Accrued taxes	(4,205)	9,094	14,652
Other current liabilities	(6,056)	(52,086)	22,520
Change in margin and collateral accounts — assets	22	(50)	404
Change in margin and collateral accounts — liabilities	4,200	350	100
Change in unrecognized tax benefits	(1,989)	(568)	2,220
Change in long-term regulatory liabilities	(332,470)	57,549	13,017
Change in other long-term assets	276,821	(246,473)	(67,453)
Change in other long-term liabilities	68,677	(29,578)	(186,227)
Net cash provided by operating activities	1,241,441	860,014	966,365
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,707,490)	(1,473,475)	(1,326,584)
Contributions in aid of construction	137,436	105,654	62,503
Allowance for borrowed funds used during construction	(28,030)	(21,052)	(18,530)
Proceeds from nuclear decommissioning trust sales and other special use funds	1,207,713	1,720,966	819,518
Investment in nuclear decommissioning trust and other special use funds	(1,212,063)	(1,725,480)	(822,608)
Other	(15,612)	6,458	7,883
Net cash used for investing activities	(1,618,046)	(1,386,929)	(1,277,818)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	875,537	746,999	1,596,672
Repayment of long-term debt	(150,000)	—	(915,150)
Short-term borrowings and (repayments) — net	48,720	142,000	73,325
Short-term debt borrowings under revolving credit facility	—	—	751,690
Short-term debt repayments under revolving credit facility	—	(19,000)	(770,690)
Dividends paid on common stock	(378,881)	(369,478)	(350,577)
Common stock equity issuance and purchases — net	(2,653)	(2,350)	(1,389)
Distributions to noncontrolling interests	(21,255)	(21,255)	(22,743)
Net cash provided by financing activities	371,468	476,916	361,138
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(5,137)	(49,999)	49,685
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	9,969	59,968	10,283
CASH AND CASH EQUIVALENTS AT END OF YEAR	\$ 4,832	\$ 9,969	\$ 59,968

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

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

	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, December 31, 2019	112,540,126	\$ 2,659,561	(103,546)	\$ (9,427)	\$ 2,837,610	\$ (57,096)	\$ 122,540	\$ 5,553,188
Net income		—		—	550,559	—	19,493	570,052
Other comprehensive loss		—		—	—	(5,700)	—	(5,700)
Dividends on common stock (\$3.23 per share)		—		—	(363,063)	—	—	(363,063)
Issuance of common stock	219,925	17,921		—	—	—	—	17,921
Purchase of treasury stock (a)		—	(81,256)	(7,181)	—	—	—	(7,181)
Reissuance of treasury stock for stock-based compensation and other		—	112,796	10,319	—	—	—	10,319
Capital activities by noncontrolling interests		—		—	—	—	(22,743)	(22,743)
Balance, December 31, 2020	112,760,051	2,677,482	(72,006)	(6,289)	3,025,106	(62,796)	119,290	5,752,793
Net income		—		—	618,720	—	17,224	635,944
Other comprehensive income		—		—	—	7,935	—	7,935
Dividends on common stock (\$3.36 per share)		—		—	(379,108)	—	—	(379,108)
Issuance of common stock	254,477	25,261		—	—	—	—	25,261
Purchase of treasury stock (a)		—	(68,892)	(4,655)	—	—	—	(4,655)
Reissuance of treasury stock for stock-based compensation and other		—	53,290	4,543	—	—	—	4,543
Capital activities by noncontrolling interests		—		—	—	—	(21,255)	(21,255)
Other		—		—	1	—	1	2
Balance, December 31, 2021	113,014,528	2,702,743	(87,608)	(6,401)	3,264,719	(54,861)	115,260	6,021,460
Net income		—		—	483,602	—	17,224	500,826
Other comprehensive income		—		—	—	23,426	—	23,426
Dividends on common stock (\$3.43 per share)		—		—	(387,975)	—	—	(387,975)
Issuance of common stock	232,661	21,996		—	—	—	—	21,996
Purchase of treasury stock (a)		—	(77,152)	(5,152)	—	—	—	(5,152)
Reissuance of treasury stock for stock-based compensation and other		—	91,147	6,548	—	—	—	6,548
Capital activities by noncontrolling interests		—		—	—	—	(21,255)	(21,255)
Other		1		—	1	—	—	2
Balance, December 31, 2022	113,247,189	\$ 2,724,740	(73,613)	\$ (5,005)	\$ 3,360,347	\$ (31,435)	\$ 111,229	\$ 6,159,876

(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, 2022, 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, 2023

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, 2022 and 2021, 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, 2022, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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, 2022, 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.

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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, recent rate orders specific to APS and to other regulated entities in the same jurisdiction, and likelihood of success of legal appeals. 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 and legal bodies, 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 regulatory accounting 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; 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; and the implementation of new rates as ordered by the ACC.
- 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 read the Company's 2022 rate application submitted to the ACC on October 28, 2022.
- 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. For certain regulatory assets or liabilities where management's assessment is based on precedents established by the ACC under similar circumstances and not specifically addressed in a regulatory order, we also obtained a letter from internal legal counsel regarding their assessment. 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.

- We evaluated management's assessment that the SCR plant investment is not probable of a partial disallowance and that the SCR deferred costs are probable of recovery. We read the Notice of Direct Appeal filed with the Arizona Court of Appeals and Petition for Special Action filed with the Arizona Supreme Court, read the Company's opening brief submitted to the Arizona Court of Appeals, read the ACC's Answering Brief, read the Intervenor's briefs, read the Company's reply brief, and observed the Appeal Oral Arguments, reviewed the Company's internally prepared memo, and reviewed a legal letter from the Company's external counsel to assess the likelihood of recovery in future rates or of a future reduction in rates based on the ACC decision.

/s/ Deloitte & Touche LLP

Tempe, Arizona
February 27, 2023

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,		
	2022	2021	2020
OPERATING REVENUES (Note 2)	\$ 4,324,385	\$ 3,803,835	\$ 3,586,982
OPERATING EXPENSES			
Fuel and purchased power	1,629,343	1,152,551	993,419
Operations and maintenance	974,220	940,588	945,181
Depreciation and amortization	753,110	650,773	614,293
Taxes other than income taxes	220,277	234,569	224,790
Other expense	2,494	6,393	7,288
Total	3,579,444	2,984,874	2,784,971
OPERATING INCOME	744,941	818,961	802,011
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	45,263	41,737	33,776
Pension and other postretirement non-service credits — net (Note 7)	98,945	112,742	57,359
Other income (Note 16)	5,888	43,053	51,755
Other expense (Note 16)	(26,108)	(18,897)	(53,694)
Total	123,988	178,635	89,196
INTEREST EXPENSE			
Interest charges	262,815	243,592	233,452
Allowance for borrowed funds used during construction (Note 1)	(26,839)	(21,052)	(18,530)
Total	235,976	222,540	214,922
INCOME BEFORE INCOME TAXES	632,953	775,056	676,285
INCOME TAXES (Note 4)	90,800	125,553	88,764
NET INCOME	542,153	649,503	587,521
Less: Net income attributable to noncontrolling interests (Note 17)	17,224	17,224	19,493
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	\$ 524,929	\$ 632,279	\$ 568,028

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,		
	2022	2021	2020
NET INCOME	\$ 542,153	\$ 649,503	\$ 587,521
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized loss, net of tax expense of \$0, \$18, and \$18	—	(18)	(18)
Reclassification of net realized gain, net of tax benefit (expense) of \$0, \$18, and \$(171) (Note 15)	—	18	592
Pension and other postretirement benefits activity, net of tax benefit (expense) of \$(6,332), \$(1,990), and \$1,955 (Note 7)	19,284	6,038	(5,970)
Total other comprehensive income (loss)	19,284	6,038	(5,396)
COMPREHENSIVE INCOME	561,437	655,541	582,125
Less: Comprehensive income attributable to noncontrolling interests	17,224	17,224	19,493
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	\$ 544,213	\$ 638,317	\$ 562,632

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

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

	December 31,	
	2022	2021
ASSETS		
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9)		
Plant in service and held for future use	\$ 22,448,685	\$ 21,685,200
Accumulated depreciation and amortization	(7,926,575)	(7,501,317)
Net	14,522,110	14,183,883
Construction work in progress	1,829,004	1,327,721
Palo Verde sale leaseback, net of accumulated depreciation of \$260,754 and \$256,884 (Note 17)	90,296	94,166
Intangible assets, net of accumulated amortization of \$816,827 and \$736,560	258,725	273,537
Nuclear fuel, net of accumulated amortization of \$126,157 and \$133,122	100,119	106,039
Total property, plant and equipment	16,800,254	15,985,346
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 12 and 18)	1,073,410	1,294,757
Other special use funds (Notes 12 and 18)	347,231	358,410
Assets from risk management activities (Note 15)	44,394	46,908
Other assets	43,344	42,440
Total investments and other assets	1,508,379	1,742,515
CURRENT ASSETS		
Cash and cash equivalents	4,042	9,374
Customer and other receivables	448,880	390,533
Accrued unbilled revenues	164,764	133,980
Allowance for doubtful accounts (Note 2)	(23,778)	(25,354)
Materials and supplies (at average cost)	410,481	349,135
Fossil fuel (at average cost)	40,155	18,032
Income tax receivable (Note 4)	1,102	10,756
Assets from risk management activities (Note 15)	87,704	63,481
Deferred fuel and purchased power regulatory asset (Note 3)	460,561	388,148
Other regulatory assets (Note 3)	78,318	130,376
Other current assets	50,043	57,729
Total current assets	1,722,272	1,526,190
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3, and 4)	1,283,221	1,192,987
Operating lease right-of-use assets (Note 8)	796,544	888,207
Assets for pension and other postretirement benefits (Note 7)	389,142	537,092
Other	44,040	37,319
Total deferred debits	2,512,947	2,655,605
TOTAL ASSETS	\$ 22,543,852	\$ 21,909,656

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

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

	December 31,	
	2022	2021
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	\$ 178,162	\$ 178,162
Additional paid-in capital	3,171,696	3,021,696
Retained earnings	3,607,464	3,470,235
Accumulated other comprehensive loss (Note 19)	(15,596)	(34,880)
Total shareholder equity	6,941,726	6,635,213
Noncontrolling interests (Note 17)	111,229	115,260
Total equity	7,052,955	6,750,473
Long-term debt less current maturities (Note 6)	6,793,529	6,266,693
Total capitalization	13,846,484	13,017,166
CURRENT LIABILITIES		
Short-term borrowings (Note 5)	325,000	278,700
Accounts payable	417,732	389,365
Accrued taxes	156,746	152,012
Accrued interest	60,518	56,622
Common dividends payable	97,900	96,000
Customer deposits	41,769	42,293
Liabilities from risk management activities (Note 15)	37,697	4,373
Liabilities for asset retirements (Note 11)	12,232	4,473
Operating lease liabilities (Note 8)	104,728	100,199
Regulatory liabilities (Note 3)	271,575	296,271
Other current liabilities	144,733	145,286
Total current liabilities	1,670,630	1,565,594
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	2,385,647	2,331,701
Regulatory liabilities (Notes 1, 3, 4 and 7)	2,061,776	2,499,213
Liabilities for asset retirements (Note 11)	785,530	762,909
Liabilities for pension benefits (Note 7)	108,068	138,328
Customer advances	422,103	257,151
Coal mine reclamation	179,255	174,616
Deferred investment tax credit	180,677	186,570
Unrecognized tax benefits (Note 4)	38,658	37,423
Operating lease liabilities (Note 8)	634,199	726,572
Other	230,825	212,413
Total deferred credits and other	7,026,738	7,326,896
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
TOTAL LIABILITIES AND EQUITY	\$ 22,543,852	\$ 21,909,656

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,		
	2022	2021	2020
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	\$ 542,153	\$ 649,503	\$ 587,521
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	817,729	719,039	686,168
Deferred fuel and purchased power	(291,992)	(256,871)	(93,651)
Deferred fuel and purchased power amortization	219,579	44,557	(12,047)
Allowance for equity funds used during construction	(45,263)	(41,737)	(33,776)
Deferred income taxes	(6,817)	128,852	36,462
Deferred investment tax credit	(5,893)	(4,802)	(5,096)
Changes in current assets and liabilities:			
Customer and other receivables	(60,930)	(72,101)	(28,206)
Accrued unbilled revenues	(30,784)	(1,783)	(4,032)
Materials, supplies and fossil fuel	(83,469)	(32,870)	11,623
Income tax receivable	9,654	(10,756)	7,313
Other current assets	59,948	(25,587)	(24,669)
Accounts payable	79,492	23,510	(4,503)
Accrued taxes	4,734	3,042	12,642
Other current liabilities	(3,010)	(61,647)	29,587
Change in margin and collateral accounts — assets	22	(50)	404
Change in margin and collateral accounts — liabilities	4,200	350	100
Change in unrecognized tax benefits	(1,989)	(568)	2,220
Change in long-term regulatory liabilities	(332,470)	57,549	13,017
Change in other long-term assets	288,077	(231,804)	(65,139)
Change in other long-term liabilities	67,131	(20,272)	(186,871)
Net cash provided by operating activities	1,230,102	865,554	929,067
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,655,051)	(1,471,795)	(1,326,584)
Contributions in aid of construction	137,436	105,654	62,503
Allowance for borrowed funds used during construction	(26,839)	(21,052)	(18,530)
Proceeds from nuclear decommissioning trust sales and other special use funds	1,207,713	1,720,966	819,518
Investment in nuclear decommissioning trust and other special use funds	(1,212,063)	(1,725,480)	(822,608)
Other	(727)	273	(554)
Net cash used for investing activities	(1,549,531)	(1,391,434)	(1,286,255)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	524,852	446,999	1,099,722
Repayment of long-term debt	—	—	(465,150)
Short-term borrowings and (repayments) — net	46,300	278,700	—
Short-term debt borrowings under revolving credit facility	—	—	540,000
Short-term debt repayments under revolving credit facility	—	—	(540,000)
Dividends paid on common stock	(385,800)	(376,500)	(357,500)
Equity infusion from Pinnacle West	150,000	150,000	150,000
Noncontrolling interests	(21,255)	(21,255)	(22,743)
Net cash provided by financing activities	314,097	477,944	404,329
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(5,332)	(47,936)	47,141
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	9,374	57,310	10,169
CASH AND CASH EQUIVALENTS AT END OF YEAR	\$ 4,042	\$ 9,374	\$ 57,310

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

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

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, December 31, 2019	71,264,947	\$ 178,162	\$ 2,721,696	\$ 3,011,927	\$ (35,522)	\$ 122,540	\$ 5,998,803
Equity infusion from Pinnacle West	—	—	150,000	—	—	—	150,000
Net income	—	—	—	568,028	—	19,493	587,521
Other comprehensive loss	—	—	—	—	(5,396)	—	(5,396)
Dividends on common stock	—	—	—	(363,000)	—	—	(363,000)
Capital activities by noncontrolling interests	—	—	—	—	—	(22,743)	(22,743)
Balance, December 31, 2020	71,264,947	178,162	2,871,696	3,216,955	(40,918)	119,290	6,345,185
Equity infusion from Pinnacle West	—	—	150,000	—	—	—	150,000
Net income	—	—	—	632,279	—	17,224	649,503
Other comprehensive income	—	—	—	—	6,038	—	6,038
Dividends on common stock	—	—	—	(379,000)	—	—	(379,000)
Capital activities by noncontrolling interests	—	—	—	—	—	(21,255)	(21,255)
Other	—	—	—	1	—	1	2
Balance, December 31, 2021	71,264,947	178,162	3,021,696	3,470,235	(34,880)	115,260	6,750,473
Equity infusion from Pinnacle West	—	—	150,000	—	—	—	150,000
Net income	—	—	—	524,929	—	17,224	542,153
Other comprehensive income	—	—	—	—	19,284	—	19,284
Dividends on common stock	—	—	—	(387,700)	—	—	(387,700)
Capital activities by noncontrolling interests	—	—	—	—	—	(21,255)	(21,255)
Balance, December 31, 2022	71,264,947	\$ 178,162	\$ 3,171,696	\$ 3,607,464	\$ (15,596)	\$ 111,229	\$ 7,052,955

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, BCE and 4CA. 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 an investment firm. BCE is a subsidiary that was formed in 2014 that focuses on growth opportunities that leverage the Company's core expertise in the electric energy industry. 4CA is a subsidiary that was formed in 2016 as a result of the purchase of El Paso's 7% interest in Four Corners. See Note 10 for more information on 4CA matters.

Pinnacle West's Consolidated Financial Statements include the accounts of Pinnacle West and our subsidiaries: APS, El Dorado, BCE and 4CA. 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, 2022, 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of accounts receivable and accrued unbilled revenues that will ultimately be uncollectible due to credit loss risk. The allowance includes a write-off component that is calculated by applying an estimated write-off factor to retail electric revenues. The write-off factor used to estimate uncollectible accounts is based upon consideration of historical collections experience, the current and forecasted economic environment, changes to our collection policies, and management's best estimate of future collections success. See Note 2.

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, 2022, and 2021 Consolidated Balance Sheets is composed of the following (dollars in thousands):

Property, Plant and Equipment:	2022	2021
Generation	\$ 9,563,145	\$ 9,480,572
Transmission	3,589,456	3,402,016
Distribution	7,951,867	7,520,016
General plant	1,347,678	1,286,057
Plant in service and held for future use	22,452,146	21,688,661
Accumulated depreciation and amortization	(7,929,878)	(7,504,603)
Net	14,522,268	14,184,058
Construction work in progress	1,882,791	1,329,478
Palo Verde sale leaseback, net of accumulated depreciation	90,296	94,166
Intangible assets, net of accumulated amortization	258,880	273,693
Nuclear fuel, net of accumulated amortization	100,119	106,039
Total property, plant and equipment	\$ 16,854,354	\$ 15,987,434

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2022, were as follows:

- Steam generation — 12 years;
- Nuclear plant — 25 years;
- Other generation — 18 years;
- Transmission — 38 years;
- Distribution — 33 years; and
- General plant — 6 years.

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. Depreciation expense was \$632 million in 2022, \$575 million in 2021, and \$553 million in 2020. For the years 2020 through 2022, the depreciation rates ranged from a low of 1.37% to a high of 12.15%. The weighted-average depreciation rate was 3.03% in 2022, 2.87% in 2021, and 2.84% in 2020.

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 5.75% for 2022, 6.75% for 2021, and 6.72% for 2020. APS compounds AFUDC semi-annually and ceases to accrue AFUDC when construction work is completed, and the property is placed in service.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 21, 2022. The order provided a simplified approach that companies may have elected to implement in order to minimize the significant distorted effect on the AFUDC formula which resulted 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 2020 and 2021 but did not impact prior years or 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

\$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 which ended December of 2022. 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,		
	2022	2021	2020
Cash paid (received) during the period for:			
Income taxes, net of refunds	\$ 46,227	\$ 229	\$ (3,019)
Interest, net of amounts capitalized	245,271	227,584	216,951
Significant non-cash investing and financing activities:			
Accrued capital expenditures	\$ 114,999	\$ 167,733	\$ 113,502
Dividends declared but not paid	97,895	95,988	93,531

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

	Year ended December 31,		
	2022	2021	2020
Cash paid during the period for:			
Income taxes, net of refunds	\$ 95,985	\$ 19,783	\$ 41,176
Interest, net of amounts capitalized	227,159	217,749	206,328
Significant non-cash investing and financing activities:			
Accrued capital expenditures	\$ 116,533	\$ 167,657	\$ 113,502
Dividends declared but not paid	97,900	96,000	93,500

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 \$84 million in 2022, \$80 million in 2021, and \$70 million in 2020. Estimated amortization expense on existing intangible assets over the next five years is \$81 million in 2023, \$60 million in 2024, \$48 million in 2025, \$33 million in 2026, and \$14 million in 2027. At December 31, 2022, the weighted-average remaining amortization period for intangible assets was 6 years.

Investments

El Dorado holds investments in both debt and equity securities. Investments in debt securities are generally accounted for as held-to-maturity and investments in equity securities are accounted for using either the equity method (if significant influence) or the measurement alternative for investments without readily determinable fair values (if less than 20% ownership and no significant influence).

BCE 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, APS obtains substantially all of the economic benefits from the use of the plant and has the right to direct the use of the plant. Purchased power lease contracts may also include energy storage facilities. Lease costs relating to purchased power lease contracts are

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2022, 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, 2022	Year Ended December 31, 2021	Year Ended December 31, 2020
Retail Electric Service			
Residential	\$ 2,046,111	\$ 1,913,324	\$ 1,929,178 (a)
Non-Residential	1,767,616	1,586,940	1,486,098
Wholesale Energy Sales	383,126	187,640	93,345
Transmission Services for Others	116,628	99,285	65,859
Other Sources	10,904	16,646	12,502
Total Operating Revenues	\$ 4,324,385	\$ 3,803,835	\$ 3,586,982

- (a) Residential revenues for the year ended December 31, 2020, reflect a \$24 million reduction related to the Arizona Attorney General matter. See Note 10.

Retail Electric Revenue. Pinnacle West's retail electric revenue is generated by wholly-owned regulated subsidiary APS's 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

Revenue Activities

Our revenues primarily consist of activities that are classified as revenues from contracts with customers. We derive our revenues from contracts with customers primarily from sales of electricity to our regulated retail customers. Revenues from contracts with customers also include wholesale and transmission activities. Our revenues from contracts with customers for the year ended December 31, 2022, 2021 and 2020 were \$4,302 million, \$3,760 million, and \$3,533 million, respectively.

We have certain revenues that do not meet the specific accounting criteria to be classified as revenues from contracts with customers. For the year ended December 31, 2022, 2021 and 2020, our revenues that do not qualify as revenue from contracts with customers were \$22 million, \$44 million and \$54 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, 2022, and 2021.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	Year Ended December 31, 2022	Year Ended December 31, 2021	Year Ended December 31, 2020
Allowance for doubtful accounts, balance at beginning of period	\$ 25,354	\$ 19,782	\$ 8,171
Bad debt expense	17,006	22,251	20,633
Actual write-offs	(18,582)	(16,679)	(9,022)
Allowance for doubtful accounts, balance at end of period	<u>\$ 23,778</u>	<u>\$ 25,354</u>	<u>\$ 19,782</u>

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 are:

- 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 and collect costs through base rates,
 - eliminate the Lost Fixed Cost Recovery mechanism and collect costs through base rates and the Demand Side Management Adjustment Charge (“DSMAC”),
 - maintain as inactive the Tax Expense Adjustor Mechanism,
 - maintain the Transmission Cost Adjustment mechanism,
 - modify the performance incentive in the DSMAC, and

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

- modify the Renewable Energy Adjustment Charge 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.

APS requested that the increase become effective December 1, 2023. The hearing for this rate case is currently scheduled to begin in August 2023. APS cannot predict the outcome of its request.

2019 Retail Rate Case

APS filed an application with the ACC on October 31, 2019 (the “2019 Rate Case”) seeking an increase in annual retail base rates of \$69 million. This amount includes recovery of the deferral and rate base effects of the Four Corners Power Plant (“Four Corners”) selective catalytic reduction (“SCR”) project that was the subject of a separate proceeding. See “Four Corners SCR Cost Recovery” below. It also reflects a net credit to base rates of approximately \$115 million primarily due to the prospective inclusion of rate refunds currently provided through the Tax Expense Adjustment Mechanism (“TEAM”). The proposed total annual revenue increase in APS’s application is \$184 million. The average annual customer bill impact of APS’s request is an increase of 5.6% (the average annual bill impact for a typical APS residential customer is 5.4%).

The principal provisions of APS’s application were:

- a test year comprised of 12 months ended June 30, 2019, adjusted as described below;
- an original cost rate base of \$8.87 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:

	<u>Capital Structure</u>	<u>Cost of Capital</u>
Long-term debt	45.3 %	4.10 %
Common stock equity	54.7 %	10.15 %
Weighted-average cost of capital		7.41 %

- 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 \$0.030168 per kWh for the Base Fuel Rate;
- authorization to defer until APS’s next general rate case the increase or decrease in its Arizona property taxes attributable to tax rate changes after the date the rate application is adjudicated;
- a number of proposed rate and program changes for residential customers, including:
 - a super off-peak period during the winter months for APS’s time-of-use with demand rates;
 - additional \$1.25 million in funding for APS’s limited-income crisis bill program; and
 - a flat bill/subscription rate pilot program;
- proposed rate design changes for commercial customers, including an experimental program designed to provide access to market pricing for up to 200 megawatt (“MW”) of medium and large commercial customers;

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

- recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project (see discussion below of the 2017 Settlement Agreement); and
- continued recovery of the remaining investment and other costs related to the retirement and closure of the Navajo Generating Station (the “Navajo Plant”) (see “Navajo Plant” below).

On October 2, 2020, the ACC Staff, the Residential Utility Consumer Office (“RUCO”) and other intervenors filed their initial written testimony with the ACC. The ACC Staff recommended, among other things, (i) an \$89.7 million revenue increase, (ii) an average annual customer bill increase of 2.7%, (iii) a return on equity of 9.4%, (iv) a 0.3% or, as an alternative, a 0% return on the increment of fair value rate base greater than original cost, (v) the recovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project and (vi) the recovery of the rate base effects of the construction and ongoing consideration of the deferral of the Ocotillo modernization project. RUCO recommended, among other things, (i) a \$20.8 million revenue decrease, (ii) an average annual customer bill decrease of 0.63%, (iii) a return on equity of 8.74%, (iv) a 0% return on the increment of fair value rate base, (v) the nonrecovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project pending further consideration, and (vi) the recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project.

The filed ACC Staff and intervenor testimony include additional recommendations, some of which materially differ from APS’s filed application. On November 6, 2020, APS filed its rebuttal testimony and the principal provisions which differ from its initial application include, among other things, (i) a \$169 million revenue increase, (ii) average annual customer bill increase of 5.14%, (iii) return on equity of 10%, (iv) return on the increment of fair value rate base of 0.8%, (v) new cost recovery adjustor mechanism, the Advanced Energy Mechanism (“AEM”), to enable more timely recovery of clean investments as APS pursues its clean energy commitment, (vi) recognition that securitization is a potentially useful financing tool to recover the remaining book value of retiring assets and effectuate a transition to a cleaner energy future that APS intends to pursue, provided legislative hurdles are addressed, and (vii) a Coal Community Transition (“CCT”) plan related to the closure or future closure of coal-fired generation facilities, of which \$25 million would be funds that are not recoverable through rates with a proposal that the remainder be funded by customers over 10 years.

The CCT plan includes the following proposed components: (i) \$100 million that will be paid over 10 years to the Navajo Nation for a sustainable transition to a post-coal economy, which would be funded by customers, (ii) \$1.25 million that will be paid over five years to the Navajo Nation to fund an economic development organization, which would be funds not recoverable through rates, (iii) \$10 million to facilitate electrification projects within the Navajo Nation, which would be funded equally by funds not recoverable through rates and by customers, (iv) \$2.5 million per year in transmission revenue sharing to be paid to the Navajo Nation beginning after the closure of the Four Corners through 2038, which would be funds not recoverable through rates, (v) \$12 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, which would primarily be funded by customers, and (vi) \$3.7 million that will be paid over five years to the Hopi Tribe related to APS’s ownership interests in the Navajo Plant, which would primarily be funded by customers. The commitment of funds that would not be recoverable through rates of \$25 million were recognized in our December 31, 2020 financials. In 2021, APS committed an additional \$0.9 million to be paid to the Hopi Tribe related to APS’s ownership interests in the Navajo Plant, and this amount was recognized in its December 31, 2021 financials.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On December 4, 2020, the ACC Staff and intervenors filed surrebuttal testimony. The ACC Staff reduced its recommended rate increase to \$59.8 million, or an average annual customer bill increase of 1.82%. In RUCO's surrebuttal, the recommended revenue decrease changed to \$50.1 million, or an average annual customer bill decrease of 1.52%. The hearing concluded on March 3, 2021, and the post-hearing briefing concluded on April 30, 2021.

On August 2, 2021, the 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 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 Navajo Plant regulatory asset recovery, (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 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, 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%, (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, results in a total annual revenue decrease for APS of \$4.8 million, excluding temporary CCT payments and expenditures. On November 2, 2021, the ACC approved the 2019 Rate Case ROO, as amended. 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. 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. The Court took the matter under advisement and will issue its decision in due course. APS cannot predict the outcome of this proceeding.

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 and will be continuing to explore whether penalties or rebates would be owed to certain customers. APS completed the implementation of the new on-peak hours for residential customers before the September 1, 2022 deadline. APS cannot predict if the ACC will take any further action on this matter.

Additionally, consistent with the 2019 Rate Case decision, as of April 2022, APS has completed the following payments that will be recoverable through rates related to the CCT: (i) \$3.33 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) \$0.5 million to the Navajo Nation for CCT; (ii) \$1.1 million to the Navajo County Communities for CCT and economic development; and (iii) \$1.25 million to the Hopi Tribe for CCT and economic development. The ACC 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.

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. APS cannot predict if the ACC will take any further action on this matter.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2016 Retail Rate Case Filing and the 2017 Settlement Agreement

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates. On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, RUCO, limited income advocates and private rooftop solar organizations signed a settlement agreement (the “2017 Settlement Agreement”) and filed it with the ACC. The 2017 Settlement Agreement provides for, among other things, a net retail base rate increase of \$94.6 million, excluding the transfer of adjustor balances, consisting of: (1) a non-fuel, non-depreciation, base rate increase of \$87.2 million per year; (2) a base rate decrease of \$53.6 million attributable to reduced fuel and purchased power costs; and (3) a base rate increase of \$61.0 million due to changes in depreciation schedules.

On August 15, 2017, the ACC approved the 2017 Settlement Agreement without material modifications, and on August 18, 2017, the ACC issued a final written Opinion and Order reflecting its decision in APS’s general retail rate case (the “2017 Rate Case Decision”). The new rates went into effect on August 19, 2017.

See “Rate Plan Comparison Tool and Investigation” below for information regarding a review and investigation pertaining to the rate plan comparison tool offered to APS customers and other related issues.

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 proposed 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.

On November 20, 2017, APS filed an updated 2018 RES budget to include budget adjustments for APS Solar Communities (formerly known as AZ Sun II), which was approved as part of the 2017 Rate Case Decision. APS Solar Communities is a 3-year program authorizing APS to spend \$10 million to \$15 million in capital costs each year to install utility-owned DG systems for 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.

On July 1, 2019, APS filed its 2020 RES Implementation Plan and proposed a budget of approximately \$86.3 million. APS’s budget request supports existing approved projects and commitments and requests a permanent waiver of the RES residential distributed energy requirement for 2020. On September 23, 2020, the ACC approved the 2020 RES Implementation Plan, including APS’s requested

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waiver of the residential distributed energy requirements for 2020. In addition, the ACC approved the implementation of a new pilot program that incentivizes Arizona households to install at-home battery systems. Recovery of the costs associated with the pilot will be addressed in the 2021 Demand Side Management Implementation Plan (“DSM Plan”).

On July 1, 2020, APS filed its 2021 RES Implementation Plan and proposed a budget of approximately \$84.7 million. APS’s budget request supports existing approved projects and commitments and requests a permanent waiver of the RES residential distributed energy requirement for 2021. In the 2021 RES Implementation Plan, APS requested \$4.5 million to meet revenue requirements associated with the APS Solar Communities program to complete installations delayed as a result of the COVID-19 pandemic in 2020. On June 7, 2021, the ACC approved the 2021 RES Implementation Plan, including APS’s requested waiver of the residential distributed energy requirements for 2021. As part of the approval, the ACC approved the requested budget and authorized APS to collect \$68.3 million through the Renewable Energy Adjustment Charge to support APS’s RES programs.

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 requests for proposals (“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 includes 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 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 supports existing approved projects and commitments and requests 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 Commission’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 is proposing a small, pilot-scale program size of up to 140MW 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. The community solar program was 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 contains funding for programs to comply with Commission-approved initiatives, including the 2019 Rate Case decision. APS’s budget proposal supports existing approved projects and commitments and requests a waiver of the RES

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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.

In response to an ACC inquiry, the ACC Staff filed a report providing the history of APS's long-term purchased power contract of the 280 MW Concentrating Solar Power Plant. This report outlines alternative options that the ACC could pursue to address the costs of this contract, which was executed in February 2008. On July 13, 2022, the ACC approved an option to take no action at this time.

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 Lost Fixed Cost Recovery ("LFCR") mechanism. See below for discussion of the LFCR.

On December 31, 2019, APS filed its 2020 DSM Plan, which requested a budget of \$51.9 million and continued APS's focus on DSM strategies such as peak demand reduction, load shifting, storage and electrification strategies. The 2020 DSM Plan addressed all components of the pending 2018 and 2019 DSM plans, which enabled the ACC to review the 2020 DSM Plan only. On May 15, 2020, APS filed an amended 2020 DSM Plan to provide assistance to customers experiencing economic impacts of the COVID-19 pandemic. The amended 2020 DSM Plan requested the same budget amount of \$51.9 million. On September 23, 2020, the ACC approved the amended 2020 DSM Plan.

On April 17, 2020, APS filed an application with the ACC requesting a COVID-19 emergency relief package to provide additional assistance to its customers. On May 5, 2020, the ACC approved APS returning \$36 million that had been collected through the DSM Adjustor Charge, but not allocated for current DSM programs, directly to customers through a bill credit in June 2020. APS has refunded approximately \$43 million to customers. The additional \$7 million over the ACC-approved amount was the result of the kWh credit being based on historic consumption which was different than actual consumption during the refund period. The difference was recorded to the DSM balancing account and was included in the 2021 DSM Implementation Plan, as described below.

On December 31, 2020, APS filed its 2021 DSM Implementation Plan, which requested a budget of \$63.7 million and continued APS's focus on DSM strategies, such as peak demand reduction, load shifting, storage and electrification strategies, as well as enhanced assistance to customers impacted economically by COVID-19. On April 6, 2021, APS filed an amended 2021 DSM Implementation Plan that proposed an additional one-time incentive for customers participating in the residential energy storage pilot program approved in the 2020 RES Implementation Plan. On July 13, 2021, the ACC approved the amended 2021 DSM Implementation Plan.

On December 17, 2021, APS filed its 2022 DSM Implementation Plan in accordance with an extension granted in 2021. The 2022 DSM 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 November 30, 2022,

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APS filed its 2023 DSM Implementation Plan, which requested a budget of \$88 million. The ACC has not yet ruled on the 2023 DSM Implementation Plan.

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.

The following table shows the changes in the deferred fuel and purchased power regulatory asset for 2022 and 2021 (dollars in thousands):

	Twelve Months Ended December 31,	
	2022	2021
Beginning balance	\$ 388,148	\$ 175,835
Deferred fuel and purchased power costs — current period	291,992	256,871
Amounts charged to customers	(219,579)	(44,558)
Ending balance	<u>\$ 460,561</u>	<u>\$ 388,148</u>

On November 27, 2019, APS filed its PSA rate for the PSA year beginning February 1, 2020. That rate was \$(0.000456) per kWh, which consisted of a forward component of \$(0.002086) per kWh and a historical component of \$0.001630 per kWh. The 2020 PSA rate is a \$0.002115 per kWh decrease compared to the 2019 PSA year. These rates went into effect as filed on February 1, 2020.

On November 30, 2020, APS filed its PSA rate for the PSA year beginning February 1, 2021. That rate was \$0.003544 per kWh, which consisted of a forward component of \$0.003434 per kWh and a historical component of \$0.000110 per kWh. The 2021 PSA rate is a \$0.004 per kWh increase compared to the 2020 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. This left \$215.9 million of fuel and purchased power costs above this annual cap which will be reflected in

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future year resets of the PSA. These rates were to be effective on February 1, 2021, but APS delayed the effectiveness of these rates until the first billing cycle of April 2021 due to concerns of the impact on customers during COVID-19. In March 2021, the ACC voted to implement the 2021 PSA rate on a staggered basis, with 50% of the rate increase taking effect in April 2021, and the remaining 50% taking effect in November 2021. The PSA rate implemented on April 1, 2021 was \$0.001544 per kWh, which consisted of a forward component of \$(0.004444) per kWh and a historical component of \$0.005988 per kWh. On November 1, 2021, the remaining increase was implemented to a rate of \$0.003544 per kWh and consisted of a forward component of \$(0.004444) per kWh and a historical component of \$0.007988 per kWh. As part of this approval, the ACC ordered ACC Staff to conduct a fuel and purchased power procurement audit to better understand the factors that contributed to the increase in fuel costs.

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 the 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, 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 is 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 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. As of October 31, 2022, the amount in the PSA balancing account was approximately \$456 million of fuel and purchased power costs. On February 23, 2023, the ACC approved a rate of \$0.019074 per kWh that will continue until further notice of the ACC. The rate will become 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 will also be required to notify the ACC when the PSA balancing account approaches \$500,000.

On March 15, 2019, APS filed an application with the ACC requesting approval to recover the costs related to two energy storage power purchase tolling agreements through the PSA, and on January 12, 2021, the ACC approved this application. On October 28, 2021, APS filed an application requesting approval to recover costs related to three additional energy storage projects through the PSA once the systems are in service, and on December 16, 2021, the ACC approved this application. On February 22, 2022, APS filed an application requesting similar recovery through the PSA for a solar plus energy storage project, and on April 13, 2022, the ACC approved this application. On December 21, 2022, APS filed an application requesting similar recovery through the PSA for a solar plus energy storage project, and on February 22, 2023, the ACC approved this application. For the applications that were approved by the ACC, the ACC has not yet ruled on prudence.

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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. There is 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, and it will become effective with the first billing cycle in April 2023 absent the ACC taking action.

Transmission Rates, Transmission Cost Adjustor (“TCA”) 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 made 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, 2020, APS’s annual wholesale transmission revenue requirement for all users of its transmission system decreased by approximately \$6.1 million for the 12-month period beginning June 1, 2020, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by \$4.8 million and retail customer rates would have decreased by approximately \$10.9 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 a total of \$7.4 million, resulting in reductions to both residential and commercial

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rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2020.

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.

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 2.5 cents for both lost residential and non-residential kWh as set forth in the 2017 Settlement Agreement. The fixed costs recoverable by the LFCR mechanism are currently 2.56 cents for lost residential and 2.68 cents for lost non-residential kWh as set forth in the 2019 Rate Case decision. The LFCR adjustment 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 14, 2020, APS filed its 2020 annual LFCR adjustment, requesting that effective May 1, 2020, the annual LFCR recovery amount be reduced to \$26.6 million (a \$9.6 million decrease from previous levels). On April 14, 2020, the ACC approved the 2020 LFCR adjustment as filed, effective with the first billing cycle in May 2020. 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

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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. APS does not believe further ACC approval is needed to move the filing date, and APS intends to file its 2023 annual LFCR adjustment later in 2023 in accordance with the July 31 deadline.

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. On December 22, 2017, the Tax Act was enacted. This legislation made significant changes to the federal income tax laws including a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018.

On August 13, 2018, APS filed a request with the ACC that addressed the return of \$86.5 million in tax savings to customers related to the amortization of non-depreciation related excess deferred taxes previously collected from customers ("TEAM Phase II"). The ACC approved this request on March 13, 2019, effective the first billing cycle in April 2019 through the last billing cycle in March 2020.

On March 19, 2020, due to the COVID-19 pandemic, APS delayed the discontinuation of TEAM Phase II until the first billing cycle in May 2020. Amounts credited to customers after the last billing cycle in March 2020 were recorded as a part of the balancing account and were addressed for recovery as part of the 2019 Rate Case. Both the timing of the reduction in revenues refunded through TEAM Phase II and the offsetting income tax benefit were recognized based upon our seasonal kWh sales pattern.

On April 10, 2019, APS filed a third request with the ACC that addressed the amortization of depreciation related excess deferred taxes over a 28.5-year period consistent with IRS normalization rules ("TEAM Phase III"). On October 29, 2019, the ACC approved TEAM Phase III providing both (i) a one-time bill credit of \$64 million which was credited to customers on their December 2019 bills, and (ii) a monthly bill credit effective the first billing cycle in December 2019 which provided an additional benefit of \$39.5 million to customers through December 31, 2020. On November 20, 2020, APS filed an application to continue the TEAM Phase III monthly bill credit through the earlier of December 31, 2021, or at the conclusion of the 2019 Rate Case. On December 9, 2020, the ACC approved this request. Both

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the timing of the reduction in revenues refunded through the TEAM Phase III monthly bill credit and the offsetting income tax benefit were recognized based upon APS's seasonal kWh sales pattern.

As part of the 2019 Rate Case decision, the TEAM rates were reset to zero beginning December 31, 2021, and all impacts of the Tax Act were removed from the TEAM and incorporated into APS's base rates. The TEAM was retained to address potential changes in tax law that may be enacted prior to a decision in a subsequent APS rate case.

Net Metering

APS's 2017 Rate Case Decision provides that payments by utilities for energy exported to the grid from residential DG solar facilities will be determined using a 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 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.

In accordance with the 2017 Rate Case Decision, APS filed its request for a RCP export energy price of 10.5 cents per kWh on May 1, 2019. This price also reflects the 10% annual reduction discussed above. The new rate rider became effective on October 1, 2019. APS filed its request for a fourth-year export energy price of 9.4 cents per kWh on May 1, 2020, with a requested effective date of September 1, 2020. This price reflects the 10% annual reduction discussed above. On September 23, 2020, the ACC approved the annual reduction of the export energy price but voted to delay the effectiveness of the reduction in export prices until October 1, 2021. In accordance with this decision, the RCP export energy price of 9.4 cents per kWh became effective on October 1, 2021. On April 29, 2022, APS filed an application to decrease the RCP price 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.

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See “2016 Retail Rate Case Filing” above for information regarding an ACC order in connection with the rate review of the 2017 Rate Case Decision requiring APS to provide grandfathered net metering customers on legacy demand rates with an opportunity to switch to another legacy rate to enable such customers to benefit from legacy net metering rates.

Subpoena from Former Arizona Corporation Commissioner Robert Burns

On August 25, 2016, then-Commissioner Robert Burns, individually and not by action of the ACC as a whole, served subpoenas in APS’s then current retail rate proceeding on APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

After various proceedings between September 2016 and March 2020, at which time Burns’ appeal of a prior dismissal by the trial court was pending before the Arizona Court of Appeals, Burns’ position as an ACC commissioner ended on January 4, 2021. Nevertheless, Burns filed a motion with the Court of Appeals arguing that the appeal was not mooted by this fact and the court should decide the matter. On March 4, 2021, the Court of Appeals found Burns’ motion to be moot because the Court of Appeals had issued an opinion deciding the matter that same day.

In its March 4, 2021, opinion, the Court of Appeals affirmed the trial court’s dismissal of Burns’ complaint, concluding that Burns could not overturn the ACC’s 4-1 vote refusing to enforce his subpoenas. On May 15, 2021, Burns filed a petition for review with the Arizona Supreme Court asking for reversal of the Court of Appeals opinion and the trial court’s judgment. APS and the ACC filed responses to Burns’ petition on July 14, 2021, requesting that the petition be denied. The Arizona Supreme Court granted Burns’ petition and heard oral argument on March 8, 2022. On September 27, 2022, the Arizona Supreme Court issued a decision in favor of Burns reversing the Court of Appeals’ decision. The Court held that the ACC acting by a majority of its commissioners may not prevent an individual commissioner from exercising investigatory powers pursuant to certain provisions of the Arizona Constitution and that a commissioner aggrieved by such action may seek judicial recourse by way of declaratory judgment. Pinnacle West and APS do not believe there will be any immediate implications given the underlying issues at hand are moot, but the Company cannot predict if or how this authority may be used by commissioners in the future.

Energy Modernization Plan

On January 30, 2018, the initial Energy Modernization Plan was proposed, which consisted of a series of energy policies tied to clean energy sources. Draft energy rules were subsequently issued and a series of revisions were made to the draft rules in 2019 and 2020. 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

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retail energy served be renewable by the end of 2035. A new Energy Efficiency Standard (“EES”) was not included in the proposed rules.

The ACC discussed the final draft energy rules at several different meetings in 2020 and 2021. On November 13, 2020, the ACC approved a final draft energy rules package. On April 19, 2021, the Administrative Law Judge issued a Recommended Order and Opinion on the final energy rules. In June 2021, the ACC adopted revised clean energy rules based on a series of ACC amendments. The adopted rules included a final standard of 100% clean energy by 2070 and the following interim standards for carbon reduction from 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 Open Meeting, Commissioners voted to postpone a decision on the All-Source RFP and IRP rulemaking package until 2023. APS cannot predict the outcome of this matter.

Integrated Resource Planning

ACC rules require utilities to develop 15-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility’s IRP to determine if it meets the necessary requirements and whether it should be acknowledged. Based on an ACC decision, APS was originally required to file its next IRP by April 1, 2020. On February 20, 2020, the ACC extended the deadline for all utilities to file their IRPs from April 1, 2020, to June 26, 2020. On June 26, 2020, APS filed its final IRP. On July 15, 2020, the ACC extended the schedule for final ACC review of utility IRPs to February 2021. In February 2022, the ACC acknowledged APS’s IRP. 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. APS intends to file its next IRP later in 2023. See “Energy Modernization Plan” above for information regarding proposed changes to the IRP filings.

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 16, 2020, FERC issued a final rule revising FERC’s regulations implementing PURPA. The final rule went into effect on December 31, 2020.

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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 and customers will have four months to pay back their deposit and any remaining delinquent amounts. 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, and APS has employed the calendar method for its disconnection moratorium.

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 beginning 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.

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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 and intends to intervene to contest it. 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 his insights on the applicable law.

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.

Rate Plan Comparison Tool and Investigation

On November 14, 2019, APS learned that its rate plan comparison tool was not functioning as intended due to an integration error between the tool and APS's meter data management system. APS immediately removed the tool from its website and notified the ACC. The purpose of the tool was to provide customers with a rate plan recommendation based upon historical usage data. Upon investigation, APS determined that the error may have affected rate plan recommendations to customers between February 4, 2019, and November 14, 2019. By the middle of May 2020, APS provided refunds to approximately 13,000 potentially impacted customers equal to the difference between what they paid for electricity and the amount they would have paid had they selected their most economical rate, as applicable, and a \$25 payment for any inconvenience that the customer may have experienced. The refunds and payment for inconvenience being provided did not have a material impact on APS's financial statements. In February 2020, APS launched a new online rate comparison tool. The ACC hired an outside consultant to evaluate the extent of the error and the overall effectiveness of the tool. On August 20, 2020, ACC Staff filed the outside consultant's report on APS's rate comparison tool. The

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report concluded APS's new rate comparison tool is working as intended. The report also identified a small population of additional customers that may have been affected by the error and APS has provided refunds and the \$25 inconvenience payment to approximately 3,800 additional customers. These additional refunds and payment for inconvenience did not have a material impact on APS's financial statements. On September 28, 2020, the ACC discussed this report but did not take any action. APS cannot predict whether additional inquiries or actions may be taken by the ACC.

APS received civil investigative demands from the Office of the Arizona Attorney General, Civil Litigation Division, Consumer Protection & Advocacy Section ("Attorney General") seeking information pertaining to the rate plan comparison tool offered to APS customers and other related issues including implementation of rates from the 2017 Settlement Agreement and its Customer Education and Outreach Plan associated with the 2017 Settlement Agreement. APS fully cooperated with the Attorney General's Office in this matter. On February 22, 2021, APS entered into a consent agreement with the Attorney General as a way to settle the matter. The settlement resulted in APS paying \$24.75 million, approximately \$24 million of which has been returned to customers as restitution. While this matter has been resolved with the Attorney General, APS cannot predict whether additional inquiries or actions may be taken by the ACC.

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 argument on November 30, 2022. The Court took the matter under advisement and will issue its decision in due course. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of December 31, 2022. If the 2019 Rate Case decision to disallow \$215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately \$154.4 million. We cannot predict the outcome of the legal

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challenges nor the timing of when this matter will be resolved. 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 has committed to end the use of coal at its remaining Cholla units by 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, \$37.2 million as of December 31, 2022, 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, \$52.6 million as of December 31, 2022, 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, \$13.9 million as of December 31, 2022. The disallowed recovery of 15% of the annual amortization does not have a material impact on APS financial statements.

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Regulatory Assets and Liabilities

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

	Amortization Through	December 31,	
		2022	2021
Pension	(a)	\$ 637,656	\$ 509,751
Deferred fuel and purchased power (b) (c)	2023	460,561	388,148
Income taxes — AFUDC equity	2052	179,631	172,393
Ocotillo deferral (e)	2031	138,143	147,650
Retired power plant costs	2033	98,692	114,841
SCR deferral (e) (f)	2031	97,624	105,771
Deferred property taxes	2027	41,057	49,626
Deferred compensation	2036	33,660	33,997
Income taxes — investment tax credit basis adjustment	2056	23,977	24,768
Palo Verde VIEs (Note 17)	2046	20,933	21,094
Active union medical trust	(g)	18,226	1,175
Four Corners cost deferral	2024	15,999	24,075
Navajo coal reclamation	2026	13,862	16,840
Lost fixed cost recovery (b)	2023	9,547	63,889
Loss on reacquired debt	2038	9,468	11,020
Mead-Phoenix transmission line — contributions in aid of construction	2050	9,048	9,380
Tax expense adjustor mechanism (b)	2031	5,845	6,501
Other	Various	8,171	10,592
Total regulatory assets (d)		\$ 1,822,100	\$ 1,711,511
Less: current regulatory assets		\$ 538,879	\$ 518,524
Total noncurrent regulatory assets		\$ 1,283,221	\$ 1,192,987

- (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. See Note 7 for further discussion.
- (b) See “Cost Recovery Mechanisms” discussion above.
- (c) Subject to a carrying charge.
- (d) There are no regulatory assets for which the ACC has allowed recovery of costs, but not allowed a return by exclusion from rate base. FERC rates are set using a formula rate as described in “Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters.”
- (e) Balance includes amounts for future regulatory consideration and amortization period determination.
- (f) See “Four Corners SCR Cost Recovery” discussion above.
- (g) Collected in retail rates.

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

	Amortization Through	December 31,	
		2022	2021
Excess deferred income taxes - ACC — Tax Cuts and Jobs Act (a)	2046	\$ 971,545	\$ 1,012,448
Excess deferred income taxes - FERC — Tax Cuts and Jobs Act (a)	2058	221,877	229,116
Asset retirement obligations	2057	354,002	614,683
Other postretirement benefits	(d)	270,604	374,816
Removal costs	(c)	106,889	119,580
Deferred fuel and purchased power — mark-to-market (Note 15)	2024	96,367	107,601
Income taxes — change in rates	2051	64,806	67,678
Four Corners coal reclamation	2038	52,592	55,392
Income taxes — deferred investment tax credit	2056	48,035	49,601
Spent nuclear fuel	2027	39,217	45,282
Renewable energy standard (b)	2024	35,720	38,640
FERC transmission true up (b)	2024	22,895	34,303
Property tax deferral (e)	2024	15,521	20,192
Sundance maintenance	2031	16,893	13,797
Demand side management (b)	2023	8,461	5,417
Tax expense adjustor mechanism (b) (e)	N/A	4,835	4,835
Other	Various	3,092	2,103
Total regulatory liabilities		\$ 2,333,351	\$ 2,795,484
Less: current regulatory liabilities		\$ 271,575	\$ 296,271
Total noncurrent regulatory liabilities		\$ 2,061,776	\$ 2,499,213

- (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.
- (e) Balance includes amounts for future regulatory consideration and amortization period determination.

4. Income Taxes

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

APS has recorded regulatory assets and regulatory liabilities related to income taxes on its Consolidated Balance Sheets in accordance with accounting guidance for regulated operations. The regulatory assets are for certain temporary differences, primarily the allowance for equity funds used

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during construction, investment tax credit (“ITC”) basis adjustment and tax expense of Medicare subsidy. The regulatory liabilities primarily relate to the change in income tax rates and deferred taxes resulting from ITCs.

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

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		
	2022	2021	2020	2022	2021	2020
Total unrecognized tax benefits, January 1	\$ 45,086	\$ 45,655	\$ 43,435	\$ 45,086	\$ 45,655	\$ 43,435
Additions for tax positions of the current year	1,399	3,305	3,418	1,399	3,305	3,418
Additions for tax positions of prior years	2,069	1,449	1,431	2,069	1,449	1,431
Reductions for tax positions of prior years for:						
Changes in judgment	(3,495)	(2,659)	(1,965)	(3,495)	(2,659)	(1,965)
Settlements with taxing authorities	—	—	—	—	—	—
Lapses of applicable statute of limitations	(1,962)	(2,664)	(664)	(1,962)	(2,664)	(664)
Total unrecognized tax benefits, December 31	<u>\$ 43,097</u>	<u>\$ 45,086</u>	<u>\$ 45,655</u>	<u>\$ 43,097</u>	<u>\$ 45,086</u>	<u>\$ 45,655</u>

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		
	2022	2021	2020	2022	2021	2020
Tax positions, that if recognized, would decrease our effective tax rate	\$ 28,246	\$ 26,300	\$ 25,714	\$ 28,246	\$ 26,300	\$ 25,714

As of the balance sheet date, the tax year ended December 31, 2019, 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 2018.

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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		
	2022	2021	2020	2022	2021	2020
Unrecognized tax benefit interest expense/(benefit) recognized	\$ (139)	\$ (535)	\$ 266	\$ (139)	\$ (535)	\$ 266

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		
	2022	2021	2020	2022	2021	2020
Unrecognized tax benefit interest accrued	\$ 1,181	\$ 1,320	\$ 1,855	\$ 1,181	\$ 1,320	\$ 1,855

Additionally, as of December 31, 2022, 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,		
	2022	2021	2020	2022	2021	2020
Current:						
Federal	\$ 35,617	\$ (5,041)	\$ 11,869	\$ 103,349	\$ 1,514	\$ 57,299
State	1,950	2,458	1,932	161	(11)	99
Total current	37,567	(2,583)	13,801	103,510	1,503	57,398
Deferred:						
Federal	23,693	95,327	53,398	(31,860)	101,175	15,122
State	13,567	17,342	10,974	19,150	22,875	16,244
Total deferred	37,260	112,669	64,372	(12,710)	124,050	31,366
Income tax expense/(benefit)	\$ 74,827	\$ 110,086	\$ 78,173	\$ 90,800	\$ 125,553	\$ 88,764

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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,		
	2022	2021	2020	2022	2021	2020
Federal income tax expense at statutory rate	\$ 120,887	\$ 156,666	\$ 136,127	\$ 132,920	\$ 162,762	\$ 142,020
Increases (reductions) in tax expense resulting from:						
State income tax net of federal income tax benefit	17,740	22,656	19,146	19,000	23,339	20,124
State income tax credits net of federal income tax benefit	(5,482)	(7,015)	(8,951)	(3,744)	(5,277)	(7,213)
Net operating loss carryback tax benefit	—	(5,915)	—	—	—	—
Excess deferred income taxes — Tax Cuts and Jobs Act	(36,241)	(36,558)	(50,543)	(36,241)	(36,558)	(50,543)
Allowance for equity funds used during construction (see Note 1)	(4,629)	(4,180)	(2,747)	(4,629)	(4,180)	(2,747)
Palo Verde VIE noncontrolling interest (see Note 17)	(3,617)	(3,617)	(4,094)	(3,617)	(3,617)	(4,094)
Investment tax credit amortization	(5,608)	(7,620)	(7,510)	(5,608)	(7,620)	(7,510)
Other federal income tax credits	(10,867)	(6,976)	(4,616)	(7,721)	(3,912)	(3,035)
Other	2,644	2,645	1,361	440	616	1,762
Income tax expense/(benefit)	\$ 74,827	\$ 110,086	\$ 78,173	\$ 90,800	\$ 125,553	\$ 88,764

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

	Pinnacle West Consolidated		APS Consolidated	
	December 31,		December 31,	
	2022	2021	2022	2021
DEFERRED TAX ASSETS				
Risk management activities	\$ 8,826	\$ 677	\$ 8,826	\$ 677
Regulatory liabilities:				
Excess deferred income taxes — Tax Cuts and Jobs Act	295,014	306,915	295,014	306,915
Asset retirement obligation and removal costs	107,104	174,952	107,104	174,952
Unamortized investment tax credits	48,035	49,601	48,035	49,601
Other postretirement benefits	66,893	92,654	66,893	92,654
Other	62,915	65,815	62,915	65,815
Operating lease liabilities	184,030	204,890	182,663	204,378
Pension liabilities	33,674	42,136	30,436	37,814
Coal reclamation liabilities	44,312	43,165	44,312	43,165
Renewable energy incentives	19,948	22,646	19,948	22,646
Credit and loss carryforwards	37,647	57,077	13,654	18,902
Other	72,605	74,184	72,605	74,184
Total deferred tax assets	981,003	1,134,712	952,405	1,091,703
DEFERRED TAX LIABILITIES				
Plant-related	(2,518,164)	(2,570,613)	(2,518,164)	(2,570,613)
Risk management activities	(32,648)	(27,276)	(32,648)	(27,276)
Pension and other postretirement assets	(96,845)	(133,624)	(96,196)	(132,769)
Other special use funds	(57,572)	(64,610)	(57,572)	(64,610)
Operating lease right-of-use assets	(184,030)	(204,890)	(182,663)	(204,378)
Regulatory assets:				
Allowance for equity funds used during construction	(44,405)	(42,616)	(44,405)	(42,616)
Deferred fuel and purchased power	(114,232)	(96,033)	(114,232)	(96,033)
Pension benefits	(157,629)	(126,010)	(157,629)	(126,010)
Retired power plant costs	(24,397)	(28,389)	(24,397)	(28,389)
Other	(103,023)	(123,902)	(103,023)	(123,902)
Other	(32,479)	(28,611)	(7,123)	(6,808)
Total deferred tax liabilities	(3,365,424)	(3,446,574)	(3,338,052)	(3,423,404)
Deferred income taxes — net	<u>\$ (2,384,421)</u>	<u>\$ (2,311,862)</u>	<u>\$ (2,385,647)</u>	<u>\$ (2,331,701)</u>

As of December 31, 2022, PNW consolidated deferred tax assets for credit and loss carryforwards relate to state credit carryforwards net of federal benefit of \$43 million, which first begin to expire in 2024. PNW consolidated credit and loss carryforwards amount above has been reduced by \$5 million of unrecognized tax benefits.

As of December 31, 2022, APS consolidated deferred tax assets for credit and loss carryforwards relate to state credit carryforwards net of federal benefit of \$19 million, which first begin to expire in 2025. APS consolidated credit and loss carryforwards amount above has been reduced by \$5 million of unrecognized tax benefits.

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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, 2022			December 31, 2021		
	Pinnacle West	APS	Total	Pinnacle West	APS	Total
Commitments under Credit Facilities	\$ 200,000	\$ 1,000,000	\$ 1,200,000	\$ 200,000	\$ 1,000,000	\$ 1,200,000
Outstanding Commercial Paper, Term Loan and Revolving Credit Facility Borrowings	(15,720)	(325,000)	(340,720)	(13,300)	(278,700)	(292,000)
Amount of Credit Facilities Available	\$ 184,280	\$ 675,000	\$ 859,280	\$ 186,700	\$ 721,300	\$ 908,000
Commitment Fees	0.175%	0.125%		0.175%	0.125%	

Pinnacle West

At December 31, 2022, Pinnacle West had a \$200 million revolving credit facility that matures on May 28, 2026. Pinnacle West has the option to increase the amount of the facility up to a maximum 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, 2022, Pinnacle West had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under the credit facility, and \$16 million of outstanding commercial paper borrowings.

APS

At December 31, 2022, APS had two \$500 million revolving credit facilities that total \$1 billion and that mature on May 28, 2026. APS may increase the amount of each facility up to a maximum of \$700 million, for a total of \$1.4 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 agreements include 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. These facilities are available to support APS's general corporate purposes, including support for APS's \$750 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2022, APS had no outstanding borrowings under its revolving credit facilities, no letters of credit outstanding under the credit facilities and \$325 million of outstanding commercial paper borrowings.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Debt Provisions

On December 17, 2020, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved 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). On December 15, 2022, the ACC issued a financing order that, among other things, reaffirmed the short-term debt authorization from the 2020 financing order. See Note 6 for additional long-term debt provisions.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

6. Long-Term Debt and Liquidity Matters

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

	Maturity Dates (a)	Interest Rates	December 31,	
			2022	2021
APS				
Pollution control bonds:				
Variable	2029	(b)	\$ 163,975	\$ 35,975
Total pollution control bonds			163,975	35,975
Senior unsecured notes	2024-2050	2.20%-6.88%	6,680,000	6,280,000
Unamortized discount			(14,548)	(14,995)
Unamortized premium			12,368	13,575
Unamortized debt issuance cost			(48,266)	(47,862)
Total APS long-term debt			6,793,529	6,266,693
Less current maturities			—	—
Total APS long-term debt less current maturities			6,793,529	6,266,693
BCE				
Los Alamitos equity bridge loan	(d)	(d)	27,575	—
Los Alamitos construction facility	(e)	(e)	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	1.3%	500,000	500,000
Term loans	2024	(c)	450,000	300,000
Unamortized discount			(25)	(34)
Unamortized debt issuance cost			(2,083)	(2,924)
Total Pinnacle West long-term debt			947,892	797,042
Less current maturities			—	150,000
Total Pinnacle West long-term debt less current maturities			947,892	647,042
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			\$ 7,741,286	\$ 6,913,735

- (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 3.96% at December 31, 2022, and 0.22% at December 31, 2021. See additional details below.
- (c) The weighted-average interest rate was 5.1% at December 31, 2022, and 0.81% at December 31, 2021. See additional details below.
- (d) The weighted-average interest rate for the variable rate equity bridge loan is 5.18% at December 31, 2022 and will mature on the project's commercial operation date, expected on or before August 15, 2023. See additional details below.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

- (e) The weighted-average interest rate for the variable rate construction facility is 5.71% at December 31, 2022 and will mature on the project's commercial operation date, expected on or before August 15, 2023. See additional details below.

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

Year	Consolidated Pinnacle West	Consolidated APS	BCE
2023	\$ 50,685	\$ —	\$ 50,685
2024	700,000	250,000	—
2025	800,000	300,000	—
2026	250,000	250,000	—
2027	300,000	300,000	—
Thereafter	5,743,975	5,743,975	—
Total	<u>\$ 7,844,660</u>	<u>\$ 6,843,975</u>	<u>\$ 50,685</u>

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, 2022		As of December 31, 2021	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	\$ 947,892	\$ 905,525	\$ 797,042	\$ 792,735
APS	6,793,529	5,629,491	6,266,693	6,933,619
BCE	50,550	50,685	—	—
Total	<u>\$ 7,791,971</u>	<u>\$ 6,585,701</u>	<u>\$ 7,063,735</u>	<u>\$ 7,726,354</u>

Credit Facilities and Debt Issuances

Pinnacle West

On December 21, 2021, Pinnacle West entered into a \$450 million term loan facility that matures December 20, 2024. On December 21, 2021, \$150 million of the proceeds were received and recognized as long-term debt on the Consolidated Balance Sheets. On January 6, 2022, the remaining \$300 million of proceeds was received and recognized on that date as long-term debt on the Consolidated Balance Sheets. The proceeds were used for general corporate purposes.

On December 23, 2020, Pinnacle West entered into a \$150 million term loan facility that was set to mature June 30, 2022. The proceeds were received on January 4, 2021, and used for general corporate purposes. We recognized the term loan facility as long-term debt upon settlement on January 4, 2021. On January 6, 2022, Pinnacle West repaid this term loan facility early.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

On January 6, 2022, Pinnacle West contributed \$150 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness.

On September 15, 2022, APS remarketed \$128 million of the Maricopa County, Arizona Pollution Control Corporation Revenue Refunding Bonds, 2009 Series B, C, D and E, due May 1, 2029 (the “Bonds”). The Bonds were originally issued on June 26, 2009, and prior to this remarketing were held as treasury bonds. Each series of the Bonds has a principal amount of \$32 million. All series of the Bonds have been remarketed and issued in weekly variable interest rate modes and are classified as long-term debt on our Consolidated Balance Sheets.

On November 8, 2022, APS issued \$400 million of 6.35% unsecured senior notes that mature December 15, 2032. The net proceeds from the sale were used to repay short-term indebtedness consisting of commercial paper, replenish cash used to fund capital expenditures, and for general corporate purposes.

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.

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 a 31 MW solar and battery storage project in Los Alamitos, California (“Los Alamitos”) that is under development by the subsidiary. The credit agreement consists of an approximately \$33 million equity bridge loan facility, an approximately \$42 million non-recourse construction facility, and an approximately \$5 million letter of credit facility. In connection with the credit agreement, Pinnacle West has issued a guarantee of up to \$42 million primarily relating to the equity bridge loan. As of December 31, 2022, \$28 million has been drawn from the equity bridge loan and there is a \$23 million outstanding balance for the construction facility and \$2.5 million letters of credit outstanding under the credit facility. The equity bridge loan and construction facility mature and are due on the project’s commercial operation date, expected on or before August 15, 2023. BCE expects to convert the construction facility into a term loan upon the project’s commercial operation date. On October 19, 2022, BCE executed an interest rate swap to hedge the variable interest rate exposure of this credit facility. See Note 15.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

capitalization not exceed 65%. At December 31, 2022, the ratio was approximately 57.7% for Pinnacle West and 50.8% 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 17, 2020, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved APS’s long-term debt authorization of \$7.5 billion. 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

Under the HRA, included in the other postretirement benefit plan, the Company provides a subsidy to retirees to defray the cost of a Medicare supplemental policy. Prior to 2020, we had been assuming a 4.75% escalation of these benefits; however, actual escalation has been significantly less than this assumption. Accordingly, during 2020 and for future periods, the escalation assumption was reduced to 2.00% (see weighted-average assumption table below). This escalation factor assumption change, among other factors, resulted in an increase in the over-funded status of the other postretirement benefit plan as of December 31, 2020. As a result, on January 4, 2021, we initiated the transfer of approximately \$106 million of investment assets from the other postretirement benefit plan into the Active Union Employee Medical Account Trust. The Active Union Employee Medical Account is an existing trust account that holds investments restricted for paying active union employee medical costs. See Note 19. The transfer of other postretirement benefit plan investment assets into the Active Union Employee Medical Account permits access to approximately \$106 million of assets for the sole purpose of paying active union employee medical benefits. This transfer of investment assets into the Active Union Employee Medical Account is consistent with the terms of a similar 2018 transaction.

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		
	2022	2021	2020	2022	2021	2020
Service cost-benefits earned during the period	\$ 55,473	\$ 61,236	\$ 56,233	\$ 16,470	\$ 17,796	\$ 22,236
Non-service costs (credits):						
Interest cost on benefit obligation	107,492	98,566	118,567	17,491	16,513	25,857
Expected return on plan assets	(185,775)	(202,628)	(187,443)	(46,042)	(41,444)	(40,077)
Amortization of:						
Prior service credit	—	—	—	(37,789)	(37,705)	(37,575)
Net actuarial (gain)/loss	17,515	15,948	34,612	(12,835)	(10,093)	—
Net periodic benefit cost/(benefit)	<u>\$ (5,295)</u>	<u>\$ (26,878)</u>	<u>\$ 21,969</u>	<u>\$ (62,705)</u>	<u>\$ (54,933)</u>	<u>\$ (29,559)</u>
Portion of cost/(benefit) charged to expense	<u>\$ (16,431)</u>	<u>\$ (32,743)</u>	<u>\$ 3,386</u>	<u>\$ (45,042)</u>	<u>\$ (38,657)</u>	<u>\$ (20,966)</u>

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

	Pension Plans		Other Benefits Plans	
	2022	2021	2022	2021
Change in Benefit Obligation				
Benefit obligation at January 1	\$ 3,716,824	\$ 3,902,867	\$ 591,841	\$ 624,034
Service cost	55,473	61,236	16,470	17,796
Interest cost	107,492	98,566	17,491	16,513
Benefit payments	(212,565)	(207,928)	(30,913)	(31,280)
Actuarial (gain) loss	(857,695)	(137,917)	(185,428)	(35,222)
Benefit obligation at December 31	<u>2,809,529</u>	<u>3,716,824</u>	<u>409,461</u>	<u>591,841</u>
Change in Plan Assets				
Fair value of plan assets at January 1	3,812,041	3,886,544	872,435	961,165
Actual return on plan assets	(787,874)	18,169	(193,807)	41,432
Employer contributions	—	100,000	—	—
Benefit payments	(194,682)	(192,672)	(26,341)	(24,310)
Transfer to active union medical account	—	—	—	(105,852)
Fair value of plan assets at December 31	<u>2,829,485</u>	<u>3,812,041</u>	<u>652,287</u>	<u>872,435</u>
Funded Status at December 31	<u>\$ 19,956</u>	<u>\$ 95,217</u>	<u>\$ 242,826</u>	<u>\$ 280,594</u>

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

	As of December 31,	
	2022	2021
Accumulated benefit obligation	126,759	161,086
Fair value of plan assets	—	—

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The Pinnacle West Capital Corporation Retirement Plan is more than 100% funded on an accumulated benefit obligation basis at December 31, 2022 and December 31, 2021, therefore the only pension plan with an accumulated benefit obligation in excess of plan assets in 2022 and 2021 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,	
	2022	2021
Projected benefit obligation	133,818	169,912
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, 2022, and December 31, 2021, therefore the only pension plan with a projected benefit obligation in excess of plan assets in 2022 and 2021 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	
	2022	2021	2022	2021
Noncurrent asset	\$ 153,773	\$ 265,129	\$ 242,826	\$ 280,594
Current liability	(17,531)	(17,047)	—	—
Noncurrent liability	(116,286)	(152,865)	—	—
Net amount recognized (funded status)	<u>\$ 19,956</u>	<u>\$ 95,217</u>	<u>\$ 242,826</u>	<u>\$ 280,594</u>

The following table shows the details related to accumulated other comprehensive loss (gain) as of December 31, 2022, and 2021 (dollars in thousands):

	Pension Plans		Other Benefits Plans	
	2022	2021	2022	2021
Net actuarial loss (gain)	\$ 681,335	\$ 582,895	\$ (195,095)	\$ (262,352)
Prior service credit	—	—	(76,843)	(114,632)
APS's portion recorded as a regulatory (asset) liability	(637,656)	(509,751)	270,604	374,816
Income tax expense (benefit)	(10,797)	(18,081)	784	990
Accumulated other comprehensive loss (gain)	<u>\$ 32,882</u>	<u>\$ 55,063</u>	<u>\$ (550)</u>	<u>\$ (1,178)</u>

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	Benefit Obligations As of December 31,		Benefit Costs For the Years Ended December 31,		
	2022	2021	2022	2021	2020
Discount rate – pension plans	5.56 %	2.92 %	2.92 %	2.53 %	3.30 %
Discount rate – other benefits plans	5.58 %	2.98 %	2.98 %	2.63 %	3.42 %
Rate of compensation increase	4.57 %	4.00 %	4.00 %	4.00 %	4.00 %
Expected long-term return on plan assets - pension plans	N/A	N/A	5.00 %	5.30 %	5.75 %
Expected long-term return on plan assets - other benefit plans	N/A	N/A	5.35 %	4.90 %	4.85 %
Initial healthcare cost trend rate (pre-65 participants)	6.50 %	6.00 %	6.00 %	6.50 %	7.00 %
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)	6	4	3	4	5
Initial and ultimate healthcare cost trend rate (post-65 participants) (a)	2.00 %	2.00 %	2.00 %	2.00 %	4.75 %
Interest crediting rate – cash balance pension plans	4.50 %	4.50 %	4.50 %	4.50 %	4.50 %

- (a) See discussion above relating to this assumptions impact on benefit obligations and the January 2021 asset transfer to the Active Union Employee Medical Account.

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 2023, we are assuming a 6.70% long-term rate of return for pension assets and 6.95% (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, and prohibition of investments in Pinnacle West securities.

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 and is a function of the plan's funded status. 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

government agencies, U.S. Treasury Futures Contracts, and fixed income debt securities issued by corporations. Long-term fixed income assets may also include interest rate swaps, and other instruments.

Return-seeking assets are intended to provide a reasonable long-term rate of investment return with a prudent level of volatility. Return-seeking assets are composed of U.S. equities, international equities, and alternative investments. International equities include investments in both developed and emerging markets. Alternative investments may include investments in real estate, private equity 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, and given the pension plan's funded status at year-end 2022, the target and actual allocation for the pension plan at December 31, 2022, 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 +/-3% 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, 2022, 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. Some of these asset allocation target mixes vary with the plan's funded status. The following table presents the actual allocations of the investment for the other postretirement benefit plan at December 31, 2022:

	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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2022, 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, 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	<u>\$ 893,285</u>	<u>\$ 1,506,809</u>	<u>\$ 429,391</u>	<u>\$ 2,829,485</u>
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	<u>\$ 371,731</u>	<u>\$ 174,200</u>	<u>\$ 106,356</u>	<u>\$ 652,287</u>

- (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.

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The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2021, by asset category, are as follows (dollars in thousands):

	Level 1	Level 2	Other (a)	Total
Pension Plan:				
Cash and cash equivalents	\$ 821	\$ —	\$ —	\$ 821
Fixed income securities:				
Corporate	—	1,765,623	—	1,765,623
U.S. Treasury	1,008,211	—	—	1,008,211
Other (b)	—	165,496	—	165,496
Common stock equities (c)	209,063	—	—	209,063
Mutual funds (d)	132,656	—	—	132,656
Common and collective trusts:				
Equities	—	—	255,141	255,141
Real estate	—	—	173,197	173,197
Partnerships	—	—	15,730	15,730
Short-term investments and other (e)	—	—	86,103	86,103
Total	\$ 1,350,751	\$ 1,931,119	\$ 530,171	\$ 3,812,041
Other Benefits:				
Cash and cash equivalents	\$ 121	\$ —	\$ —	\$ 121
Fixed income securities:				
Corporate	—	244,572	—	244,572
U.S. Treasury	287,057	—	—	287,057
Other (b)	—	9,330	—	9,330
Common stock equities (c)	176,024	—	—	176,024
Mutual funds (d)	26,262	—	—	26,262
Common and collective trusts:				
Equities	—	—	96,547	96,547
Real estate	—	—	23,851	23,851
Short-term investments and other (e)	2,517	—	6,154	8,671
Total	\$ 491,981	\$ 253,902	\$ 126,552	\$ 872,435

- (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. We made contributions to our pension plan totaling \$0 million in 2022, \$100 million in 2021, and \$100 million in 2020. 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 2023, 2024 or 2025. With regard to contributions to our other postretirement benefit plan, we did not make a contribution in 2022 or 2021 and do not expect to make any contributions in 2023, 2024 or 2025. The Company was reimbursed

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

\$26 million in 2022, \$24 million in 2021, and \$26 million in 2020 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
2023	\$ 240,034	\$ 31,235
2024	227,234	30,865
2025	223,813	30,251
2026	224,881	30,135
2027	221,976	29,790
Years 2028-2032	1,117,192	146,725

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 2022, 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 2022, \$12 million for 2021, and \$11 million for 2020.

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 agreements that qualify as lease arrangements. Our leases have remaining terms that expire in 2023 through 2052. 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

non-consecutive periods of use. APS does not operate or maintain these leased assets. APS controls the dispatch of these leased assets and is required to pay fixed monthly capacity payments during the 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. These purchased power lease contracts are accounted for as operating leases. The contracts do not contain purchase options or term extension options. In addition to the fixed monthly capacity payment, APS must also pay variable charges based on the actual production volume of the asset. The variable consideration is not included in the measurement of our lease obligation.

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

	For the Year Ended December 31,		
	2022	2021	2020
Operating Lease Cost - Purchased Power Lease Contracts	\$ 104,001	\$ 105,762	68,883
Operating Lease Cost - Land, Property, and Other Equipment	18,061	18,498	18,493
Total Operating Lease Cost	122,062	124,260	87,376
Variable lease cost (a)	122,040	118,969	122,331
Short-term lease cost	9,928	3,872	3,804
Total lease cost	<u>\$ 254,030</u>	<u>\$ 247,101</u>	<u>\$ 213,511</u>

(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 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 generation 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.

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

Year	December 31, 2022		
	Purchased Power Lease Contracts	Land, Property & Equipment Leases	Total
2023	\$ 106,151	\$ 14,254	\$ 120,405
2024	104,315	11,330	115,645
2025	106,582	8,655	115,237
2026	120,016	7,207	127,223
2027	89,108	5,292	94,400
Thereafter	210,486	37,873	248,359
Total lease commitments	736,658	84,611	821,269
Less imputed interest	57,682	19,130	76,812
Total lease liabilities	\$ 678,976	\$ 65,481	\$ 744,457

We recognize lease assets and liabilities upon lease commencement. At December 31, 2022, we have various lease arrangements that have been executed but have not yet commenced. 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 expected lease commencement dates ranging from June 2023 through June 2025, with lease terms expiring through May 2045. We expect the total fixed consideration paid for these arrangements, which includes both lease and non-lease payments, will approximate \$2.7 billion over the 20-year terms of the agreements.

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. In January 2023, as a result of these modifications, APS recorded an additional \$537 million of operating lease liabilities and right-of-use operating lease assets. These obligations relate to payments that will occur during the periods 2023 through 2034.

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, 2022	Year Ended December 31, 2021	Year Ended December 31, 2020
Cash paid for amounts included in the measurement of lease liabilities — operating cash flows:	\$ 118,463	\$ 116,661	\$ 75,097
Right-of-use operating lease assets obtained in exchange for operating lease liabilities	16,990	500,582	441,653

	December 31, 2022	December 31, 2021
Weighted average remaining lease term	7 years	8 years
Weighted average discount rate (a)	2.21 %	2.13 %

- (a) 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, 2022 (dollars in thousands):

	Percent Owned		Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating facilities:					
Palo Verde Units 1 and 3	29.1 %		\$ 1,947,593	\$ 1,099,132	\$ 39,933
Palo Verde Unit 2 (a)	16.8 %		659,514	383,775	14,784
Palo Verde Common	28.0 %	(b)	799,794	346,705	52,631
Palo Verde Sale Leaseback		(a)	351,050	260,754	—
Four Corners Generating Station	63.0 %		1,665,042	620,918	46,643
Cholla Common Facilities (c)	50.5 %		207,104	140,886	2,988
Transmission facilities:					
ANPP 500kV System	33.4 %	(b)	133,887	55,704	2,820
Navajo Southern System	26.8 %	(b)	90,345	36,929	1,945
Palo Verde — Yuma 500kV System	25.4 %	(b)	24,026	7,559	128
Four Corners Switchyards	61.9 %	(b)	73,243	20,350	120
Phoenix — Mead System	17.1 %	(b)	39,705	20,055	51
Palo Verde — Rudd 500kV System	50.0 %		95,736	31,118	391
Morgan — Pinnacle Peak System	64.7 %	(b)	119,785	25,791	96
Round Valley System	50.0 %		548	193	—
Palo Verde — Morgan System	87.8 %	(b)	263,576	34,415	1,414
Hassayampa — North Gila System	80.0 %		148,174	22,566	3,771
Cholla 500kV Switchyard	85.7 %		8,100	2,380	—
Saguaro 500kV Switchyard	60.0 %		21,656	13,809	—
Kyrene — Knox System	50.0 %		578	336	—
Agua Fria Switchyard	10.0 %		—	—	32

(a) See Note 17.

(b) Weighted-average of interests.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

10. Commitments and Contingencies

Palo Verde Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against 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, 2022. An additional extension is currently pending.

APS has submitted eight claims pursuant to the terms of the August 18, 2014 settlement agreement, for eight separate time periods during July 1, 2011 through June 30, 2021. The DOE has approved and paid \$123.9 million for these claims (APS’s share is \$36.0 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 4. On October 31, 2022, APS filed its ninth claim pursuant to the terms of the August 18, 2014 settlement agreement in the amount of \$14.3 million (APS’s share is \$4.2 million). In February 2023, the DOE approved 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. In accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident up to approximately \$13.7 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of \$450 million, which is provided by American Nuclear Insurers. The remaining balance of approximately \$13.2 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 \$137.6 million, subject to a maximum annual premium of approximately \$20.5 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 \$120.1 million, with a maximum annual retrospective premium of approximately \$17.9 million.

The Palo Verde participants maintain insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of \$2.8 billion. APS has also secured accidental outage insurance for a sudden and unforeseen accidental outage of any of the three units. The property damage,

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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 \$22.3 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 \$62.8 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 2023 and 2043 that include required purchase provisions. APS estimates the contract requirements to be approximately \$955 million in 2023; \$823 million in 2024; \$882 million in 2025; \$905 million in 2026; \$819 million in 2027; and \$8.7 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):

	Years Ended December 31,					
	2023	2024	2025	2026	2027	Thereafter
Coal take-or-pay commitments (a)	\$ 216,729	\$ 211,823	\$ 232,594	\$ 225,345	\$ 204,845	\$ 880,113

- (a) Total take-or-pay commitments are approximately \$2.0 billion. The total net present value of these commitments is approximately \$1.6 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):

	Years Ended December 31,		
	2022	2021	2020
Total purchases	\$ 305,502	\$ 219,958	\$ 189,817

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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 \$31 million in 2023; \$29 million in 2024; \$27 million in 2025; \$23 million in 2026; \$19 million in 2027; and \$69 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 \$179 million at December 31, 2022, and \$175 million at December 31, 2021. Under our current coal supply agreements, APS expects to make payments for the final mine reclamation as follows: \$18 million in 2023; \$19 million in 2024; \$20 million in 2025; \$21 million in 2026; \$22 million in 2027; and \$25 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-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 (“PRPs”). 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.

On August 6, 2013, the Roosevelt Irrigation District (“RID”) filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID’s groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS’s current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, the

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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. On December 16, 2016, two RID environmental and engineering contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another RID service provider filed an additional ancillary CERCLA lawsuit against certain of the defendants in the main RID litigation but excluded APS and certain other parties as named defendants. Because the ancillary lawsuits concern past costs allegedly incurred by these RID vendors, which were ruled unrecoverable directly by RID in November of 2016, the additional lawsuits do not increase APS's exposure or risk related to these matters.

On April 5, 2018, RID and the defendants in that particular litigation executed a settlement agreement, fully resolving RID's CERCLA claims concerning both past and future cost recovery. APS's share of this settlement was immaterial. In addition, the two environmental and engineering vendors voluntarily dismissed their lawsuit against APS and the other named defendants without prejudice. An order to this effect was entered on April 17, 2018. With this disposition of the case, the vendors may file their lawsuit again in the future. On August 16, 2019, Maricopa County, one of the three direct defendants in the ancillary service provider lawsuit, filed a third-party complaint seeking contribution for its liability, if any, from APS and 28 other third-party defendants. While this lawsuit remains pending, on September 30, 2022, the U.S. District Court for the District of Arizona granted partial summary judgment to the direct defendants for \$20.7 million of the \$21 million in CERCLA response costs claimed by the service provider. We are unable to predict the outcome of any further litigation related to the remaining response costs at issue in this litigation; however, we do not expect the outcome to have a material impact on our financial position, results of operations, or cash flows.

On February 28, 2022, EPA provided APS with a request for information under CERCLA related to APS's Ocotillo power plant site located in Tempe, Arizona. In particular, EPA seeks information from APS regarding APS's use, storage, and disposal of substances containing per-and polyfluoroalkyl ("PFAS") compounds at the Ocotillo power plant site in order to aid EPA's investigation into actual or threatened releases of PFAS into groundwater within the South Indian Bend Wash ("SIBW") Superfund site. The SIBW Superfund site includes the APS Ocotillo power plant site. APS filed its response to this information request on April 29, 2022. On January 17, 2023, EPA contacted APS to inform 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. At the present time, we are unable to predict the outcome of this matter and expenditures related to this matter cannot be reasonably estimated.

Arizona Attorney General Matter

APS received civil investigative demands from the Attorney General seeking information pertaining to the rate plan comparison tool offered to APS customers and other related issues including implementation of rates from the 2017 Settlement Agreement and its Customer Education and Outreach Plan associated with the 2017 Settlement Agreement. APS fully cooperated with the Attorney General's Office in this matter. On February 22, 2021, APS entered into a consent agreement with the Attorney General as a way to settle the matter. The settlement resulted in APS paying \$24.75 million, approximately \$24 million of which was returned to customers as restitution.

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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. The Court took the matter under advisement and will issue its decision in due course. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of December 31, 2022. If the 2019 Rate Case decision to disallow \$215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately \$154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See Note 3 for additional information regarding the Four Corners SCR cost recovery.

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 GHGs, water quality, wastewater discharges, solid waste, hazardous waste, and CCRs. These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates but cannot predict whether it will obtain such recovery. The following proposed and final rules involve material compliance costs to APS.

Regional Haze Rules. APS has received the final rulemaking imposing pollution control requirements on Four Corners. EPA required the plant to install pollution control equipment that constitutes BART to lessen the impacts of emissions on visibility surrounding the plant.

Based on EPA's final standards, APS's 63% share of the cost of required controls for Four Corners Units 4 and 5 was approximately \$400 million, which has been incurred. In addition, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in Four Corners Units 4 and 5. 4CA purchased the El Paso interest on July 6, 2016. NTEC purchased the interest from 4CA on July 3, 2018. The cost of the pollution controls related to the 7% interest is approximately \$45 million, which was assumed by NTEC through its purchase of the 7% interest. In addition, EPA issued a final rule for Regional Haze compliance at Cholla that does not involve the installation of new pollution controls and that will replace an earlier BART determination for this facility. See "Cholla" in Note 3 for information regarding future plans for Cholla and details related to the resulting regulatory asset.

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

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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, including supporting the passage of new state legislation 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. 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 2023.

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 APS’s financial position, results of operations, or cash flows.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

approximately \$30 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately \$16 million. 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. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from \$10 million to \$15 million, which would be incurred over 30 years. The analysis needed to perform a similar cost estimate for Cholla remains ongoing at this time. 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 process, APS cannot predict any ultimate impacts to the Company; however, at this time APS does not believe the cost estimates for Cholla and any potential change to the cost estimate for Four Corners would have a material impact on its financial position, results of operations, or cash flows.

Clean Power Plan/Affordable Clean Energy Regulations. On June 19, 2019, EPA took final action on its proposals to repeal EPA's 2015 Clean Power Plan ("CPP") and replace those regulations with a new rule, the Affordable Clean Energy ("ACE") regulations. EPA originally finalized the CPP on August 3, 2015, and such rules would have had far broader impact on the electric power sector than the ACE regulations. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new existing power plant carbon regulations consistent with the court's ruling. That decision, which endorsed an expansive view of the federal Clean Air Act consistent with EPA's 2015 CPP, was subsequently reversed by the U.S. Supreme Court on June 30, 2022. While the current administration has expressed its intent to develop new carbon emission regulations governing existing power plants sometime in 2023, such action will be constrained by the U.S. Supreme Court's decision that the CPP violated the Clean Air Act. Nonetheless, we cannot at this time predict the outcome of pending EPA rulemaking proceedings related to carbon emissions from existing power plants.

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 our 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.

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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. EPA then issued a revised final NPDES permit for Four Corners on September 30, 2019. Based upon a November 1, 2019, filing by several environmental groups, the EAB again took up review of the Four Corners NPDES Permit. Oral argument on this appeal was held on September 3, 2020, and 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 this 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 is not expected to have a material impact on APS’s financial position, results of operations, or cash flows.

Four Corners — 4CA Matter

On July 6, 2016, 4CA purchased El Paso’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.

BCE Matters

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 and filed a complaint with FERC on May 21, 2021, which was denied on September 9, 2022. Subsequently, Tenaska Clear Creek Wind, LLC filed with FERC a request for rehearing and a motion for stay of the September 9, 2022 order. On October 7, 2022, the request for rehearing was denied by FERC. FERC has not ruled on the motion for stay. Clear Creek has filed a Petition for Review with the U.S. Court of Appeals and Motion for Stay Pending Appeal, both of which are still pending.

Tenaska Clear Creek Wind, LLC filed a second complaint with FERC on May 25, 2022, alleging that the wind farm was being curtailed in a discriminatory manner. The May 25, 2022 Complaint was denied by FERC on December 15, 2022 and Tenaska Clear Creek Wind, LLC requested Rehearing of the denial on January 13, 2023.

Due to the disputed system upgrades and the related curtailment, 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. These energy curtailments are expected to persist, unless and until system upgrades are implemented to alleviate the present transmission system congestion,

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or the disputes are determined in favor of, or settled in a manner favorable to, Tenaska Clear Creek Wind, LLC. As such, during the fourth quarter of 2022, due to these on-going disputes, cost allocation uncertainties, and no probable favorable resolution, BCE determined its equity method investment was fully impaired. Prior to the impairment, the investment had a carrying value of \$17.1 million, which has been 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.

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, 2022, standby letters of credit totaled approximately \$10 million and will expire in 2023. As of December 31, 2022, surety bonds expiring through 2025 totaled approximately \$8 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, 2022. 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 BCE's acquisition of minority ownership positions in the Clear Creek wind farm in Missouri and Nobles 2 wind farm in Minnesota, Pinnacle West has issued parental guarantees to guarantee the obligations of BCE subsidiaries to make required equity contributions to fund project construction (the "Equity Contribution Guarantees") and 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, 2022 there is approximately \$34 million of remaining guarantees primarily relating to the PTC Guarantees that is expected to terminate by 2030.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In connection with the credit agreement entered into by a special purpose subsidiary of BCE on February 11, 2022, Pinnacle West has issued a guarantee of up to \$42 million primarily related to the bridge loan. See Note 6 for additional details.

11. Asset Retirement Obligations

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

In 2021, APS revised its cost estimates for existing AROs at Cholla related to updated estimates for the closure of ponds and facilities, which resulted in an increase to the ARO of approximately \$28 million. See additional details in Notes 3 and 10.

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

	2022	2021
Asset retirement obligations at the beginning of year	\$ 767,382	\$ 705,083
Changes attributable to:		
Accretion expense	41,240	38,437
Settlements	(10,860)	(4,111)
Estimated cash flow revisions	—	27,973
Asset retirement obligations at the end of year	<u>\$ 797,762</u>	<u>\$ 767,382</u>

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. Our long-dated energy transactions 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 relate to an interest rate swap, which is valued using financial models that utilize observable inputs for similar instruments and are classified as Level 2. Inputs include yield curves and credit quality of the counterparties.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

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Fair Value Tables

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):

	Level 1	Level 2	Level 3	Other		Total
ASSETS						
Risk management activities — derivative instruments:						
Commodity contracts	\$ —	\$ 127,129	\$ 26,132	\$ (21,163) (a)		\$ 132,098
Interest rate swaps	—	131	—	—		131
Subtotal risk management activities - derivative instruments	—	127,260	26,132	(21,163)		132,229
Nuclear decommissioning trust:						
Equity securities	14,658	—	—	3,827 (b)		18,485
U.S. commingled equity funds	—	—	—	472,582 (c)		472,582
U.S. Treasury debt	211,923	—	—	—		211,923
Corporate debt	—	149,226	—	—		149,226
Mortgage-backed securities	—	147,938	—	—		147,938
Municipal bonds	—	64,881	—	—		64,881
Other fixed income	—	8,375	—	—		8,375
Subtotal nuclear decommissioning trust	226,581	370,420	—	476,409		1,073,410
Other special use funds:						
Equity securities	66,974	—	—	963 (b)		67,937
U.S. Treasury debt	275,267	—	—	—		275,267
Municipal bonds	—	4,027	—	—		4,027
Subtotal other special use funds	342,241	4,027	—	963		347,231
Total assets	\$ 568,822	\$ 501,707	\$ 26,132	\$ 456,209		\$ 1,552,870
LIABILITIES						
Risk management activities — derivative instruments:						
Commodity contracts	\$ —	\$ (25,874)	\$ (31,020)	\$ 15,357 (a)		\$ (41,537)
Interest rate swaps	—	(909)	—	—		(909)
Subtotal risk management activities - derivative instruments	—	(26,783)	(31,020)	15,357		(42,446)
Total liabilities	\$ —	\$ (26,783)	\$ (31,020)	\$ 15,357		\$ (42,446)

(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.

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The following table presents the fair value at December 31, 2021, of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
ASSETS						
Risk management activities — derivative instruments:						
Commodity contracts	\$ —	\$ 115,079	\$ —	\$ (4,690)	(a)	\$ 110,389
Nuclear decommissioning trust:						
Equity securities	45,264	—	—	(27,782)	(b)	17,482
U.S. commingled equity funds	—	—	—	595,048	(c)	595,048
U.S. Treasury debt	240,745	—	—	—		240,745
Corporate debt	—	203,454	—	—		203,454
Mortgage-backed securities	—	155,574	—	—		155,574
Municipal bonds	—	72,189	—	—		72,189
Other fixed income	—	10,265	—	—		10,265
Subtotal nuclear decommissioning trust	286,009	441,482	—	567,266		1,294,757
Other special use funds:						
Equity securities	47,570	—	—	936	(b)	48,506
U.S. Treasury debt	298,170	—	—	—		298,170
Municipal bonds	—	11,734	—	—		11,734
Subtotal other special use funds	345,740	11,734	—	936		358,410
Total assets	\$ 631,749	\$ 568,295	\$ —	\$ 563,512		\$ 1,763,556
LIABILITIES						
Risk management activities — derivative instruments:						
Commodity contracts	\$ —	(4,740)	(2,738)	3,105	(a)	(4,373)

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

(b) Represents net pending securities sales and purchases.

(c) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

Fair Value Measurements Classified as Level 3

The significant unobservable inputs used in the fair value measurement of our energy derivative contracts include broker quotes that cannot be validated as an observable input primarily due to the long-term nature of the quote or other characteristics of the product. Significant changes in these inputs in isolation would result in significantly higher or lower fair value measurements. Changes in our derivative contract fair values, including changes relating to unobservable inputs, typically will not impact net income due to regulatory accounting treatment. See Note 3.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Because our forward commodity contracts classified as Level 3 are currently in a net purchase position, we would expect price increases of the underlying commodity to result in increases in the net fair value of the related contracts. Conversely, if the price of the underlying commodity decreases, the net fair value of the related contracts would likely decrease.

Other unobservable valuation inputs include credit and liquidity reserves which do not have a material impact on our valuations; however, significant changes in these inputs could also result in higher or lower fair value measurements.

The following tables provide information regarding our significant unobservable inputs used to value our risk management derivative Level 3 instruments at December 31, 2022 and December 31, 2021:

Commodity Contracts	December 31, 2022 Fair Value (thousands)		Valuation Technique	Significant Unobservable Input	Range	Weighted- Average (b)
	Assets	Liabilities				
Electricity:						
Forward Contracts (a)	\$ 26,132	\$ 1,759	Discounted cash flows	Electricity forward price (per MWh)	\$37.79 - \$310.69	\$ 163.92
Natural Gas:						
Forward Contracts (a)	—	29,261	Discounted cash flows	Natural gas forward price (per MMBtu)	\$(11.81) - \$0.00	\$ (5.08)
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.

Commodity Contracts	December 31, 2021 Fair Value (thousands)		Valuation Technique	Significant Unobservable Input	Range			Weighted- Average (b)			
	Assets	Liabilities									
Natural Gas:											
Forward Contracts (a)	\$	—	\$	2,738	Discounted cash flows	Natural gas forward price (per MMBtu)	\$(0.76)	-	\$(0.65)	\$	(0.71)
Total	\$	—	\$	2,738							

(a) Includes swaps and physical and financial contracts.

(b) Unobservable inputs were weighted by the relative fair value of the instrument.

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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 for the years ended December 31, 2022 and 2021 (dollars in thousands):

	Year Ended December 31,	
	2022	2021
Commodity Contracts		
Net derivative balance at beginning of period	\$ (2,738)	\$ (1,102)
Total net gains (losses) realized/unrealized:		
Deferred as a regulatory asset or liability	(374)	13,827
Settlements	(1,123)	(15,463)
Transfers into Level 3 from Level 2	(846)	—
Transfers from Level 3 into Level 2	193	—
Net derivative balance at end of period	\$ (4,888)	\$ (2,738)
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.

Nonrecurring Fair Value Measurements

As of December 31, 2022, the fair value of BCE's impaired equity method investment that is measured at fair value on a nonrecurring basis was zero, which was valued using significant unobservable inputs (Level 3). The total tax effected impairment charge included in net income for the year ended December 31, 2022 was \$12.8 million. See Note 10 for additional information.

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):

	2022	2021	2020
Net income attributable to common shareholders	\$ 483,602	\$ 618,720	\$ 550,559
Weighted average common shares outstanding — basic	113,196	112,910	112,666
Net effect of dilutive securities:			
Contingently issuable performance shares and restricted stock units	220	282	276
Weighted average common shares outstanding — diluted	113,416	113,192	112,942
Earnings per weighted-average common share outstanding			
Net income attributable to common shareholders — basic	\$ 4.27	\$ 5.48	\$ 4.89
Net income attributable to common shareholders — diluted	\$ 4.26	\$ 5.47	\$ 4.87

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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 authorizes up to 1.3 million common shares to be available for grant. As of December 31, 2022, 0.9 million common shares were available for issuance under the 2021 Plan. During 2022, 2021, and 2020, 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 \$16 million in 2022, \$18 million in 2021, and \$18 million in 2020. The compensation cost capitalized is immaterial for all years. Income tax benefits related to stock-based compensation arrangements were \$2 million in 2022, \$3 million in 2021, and \$4 million in 2020.

As of December 31, 2022, there were approximately \$20 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 \$25 million in 2022, \$22 million in 2021 and \$22 million in 2020.

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)		
	2022	2021	2020	2022	2021	2020
Units granted	174,791	152,345	118,403	208,736	161,840	122,830
Weighted-average grant date fair value	\$ 69.66	\$ 76.72	\$ 71.70	\$ 77.63	\$ 82.42	\$ 104.74

- (a) Units granted includes awards that will be cash settled of 0 in 2022, 51,074 in 2021, and 45,646 in 2020. 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, 2021	253,156	\$ 79.37	280,682	\$ 92.16
Granted	174,791	69.66	208,736	77.63
Vested	(101,216)	84.52	(136,034)	103.30
Forfeited (c)	(9,144)	76.56	(22,690)	78.29
Nonvested at December 31, 2022	317,587	(a) 73.91	330,694	78.91
Vested Awards Outstanding at December 31, 2022	78,912		136,034	

(a) Includes 69,413 of awards that will be cash settled.

(b) The nonvested 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 \$3 million, \$4 million, and \$6 million in 2022, 2021 and 2020, respectively. This includes cash used to settle restricted stock units of \$3 million, \$3 million, and \$4 million in 2022, 2021 and 2020, 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. The members of the Board of Directors who elect to defer may elect to receive payment in either 100% stock, 100% cash, or 50% in cash and 50% in stock. The stock units include 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 sheet 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):

Commodity	Unit of Measure	Quantity	
		December 31, 2022	December 31, 2021
Power	GWh	1,197	—
Gas	Billion cubic feet	149	155

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Gains and Losses from Energy Derivative Instruments

The following table provides information about APS's gains and losses from energy derivative instruments in designated cash flow accounting hedging relationships (dollars in thousands):

Commodity Contracts	Financial Statement Location	Year Ended December 31,		
		2022	2021	2020
Loss Reclassified from Accumulated OCI into Income (Effective Portion Realized) (a)	Fuel and purchased power (b)	\$ —	\$ —	\$ (763)

- (a) During the years ended December 31, 2022, 2021, and 2020, we had no gains or losses reclassified from accumulated OCI to earnings related to discontinued cash flow hedges.
- (b) Amounts are before the effect of PSA deferrals.

During the next twelve months, we estimate that no amounts will be reclassified from accumulated OCI into income. For APS, the delivery period for all energy derivative instruments in designated cash flow accounting hedging relationships have lapsed.

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,		
		2022	2021	2020
Net Gain (Loss) Recognized in Income	Fuel and purchased power (a)	\$ 307,287	\$ 216,847	\$ (3,178)

- (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, 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.

As of December 31, 2021: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amounts Reported on Balance Sheets
Current assets	\$ 66,777	\$ (3,346)	\$ 63,431	\$ 50	\$ 63,481
Investments and other assets	48,302	(1,394)	46,908	—	46,908
Total assets	115,079	(4,740)	110,339	50	110,389
Current liabilities	(6,084)	3,346	(2,738)	(1,635)	(4,373)
Deferred credits and other	(1,394)	1,394	—	—	—
Total liabilities	(7,478)	4,740	(2,738)	(1,635)	(4,373)
Total	\$ 107,601	\$ —	\$ 107,601	\$ (1,585)	\$ 106,016

- (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 \$1,635 thousand and cash margin provided to counterparties of \$50 thousand.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 Los Alamitos credit agreement. The transaction qualifies and has been designated as cash flow hedge. The hedge's gain or loss is reported as a component of other comprehensive income and subsequently will be reclassified into earnings in the periods during which the related interest expense on the debt is incurred. As of December 31, 2022, the interest rate swap has a notional value of \$32 million with a maturity in 2041. Relating to this derivative, our Consolidated Balance Sheet as of December 31, 2022 includes approximately \$0.9 million reported within the liabilities from risk management activities line within the deferred credits and other section, and \$0.1 million reported within the current assets from risk management activities line. For the year ended December 31, 2022, the Consolidated Income Statement includes a pretax loss of approximately \$0.8 million recognized in other comprehensive income relating to the interest rate swap. There were no gains or losses reclassified out of accumulated other comprehensive income for the year ended December 31, 2022, and we expect no significant amounts will be reclassified into earnings over the next 12 months.

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, 2022, we have two counterparties for which our exposure represents approximately 21% of Pinnacle West's \$132 million of risk management assets. This exposure relates to master agreements with the counterparties and both are rated as investment grade. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of our trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these counterparties could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of financial institutions, major energy companies, municipalities, and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. To manage credit risk, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

Certain of our energy derivative instrument contracts contain credit-risk-related contingent features including, among other things, investment grade credit rating provisions, credit-related cross-default provisions, and adequate assurance provisions. Adequate assurance provisions allow a counterparty with reasonable grounds for uncertainty to demand additional collateral based on subjective events and/or conditions. For those energy derivative instruments in a net liability position, with investment grade credit contingencies, the counterparties could demand additional collateral if our debt credit rating were to fall below investment grade (below BBB- for Standard & Poor's or Fitch or Baa3 for Moody's).

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	December 31, 2022
Aggregate fair value of derivative instruments in a net liability position	\$ 56,893
Cash collateral posted	—
Additional cash collateral in the event credit-risk related contingent features were fully triggered (a)	32,884

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

We also have energy related non-derivative instrument contracts with investment grade credit-related contingent features, which could also require us to post additional collateral of approximately \$76 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 2022, 2021 and 2020 (dollars in thousands):

	2022	2021	2020
Other income:			
Interest income	\$ 7,326	\$ 6,726	\$ 12,210
Investment gains (losses) — net	—	—	2,358
Debt return on Four Corners SCR deferral (Note 3)	—	14,955	15,865
Debt return on Ocotillo modernization project (Note 3)	—	23,366	26,121
Miscellaneous	590	53	149
Total other income	<u>\$ 7,916</u>	<u>\$ 45,100</u>	<u>\$ 56,703</u>
Other expense:			
Non-operating costs	\$ (18,619)	\$ (13,008)	\$ (12,400)
Investment gains (losses) — net	(20,537)	(b) (1,367)	—
Miscellaneous	(13,229)	(a) (11,021)	(45,376) (a)
Total other expense	<u>\$ (52,385)</u>	<u>\$ (25,396)</u>	<u>\$ (57,776)</u>

- (a) The 2022 miscellaneous amount includes donations of \$7 million to the APS Foundation. The 2020 miscellaneous amount includes donations of approximately \$10 million to the APS Foundation and approximately \$25.2 million related to the CCT plan. See Note 3.
- (b) The 2022 investment loss is primarily related to an impairment write-off of BCE's Clear Creek wind farm investment. See Note 10.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Other Income and Other Expense - APS

The following table provides detail of APS's other income and other expense for 2022, 2021 and 2020 (dollars in thousands):

	2022	2021	2020
Other income:			
Interest income	\$ 5,332	\$ 4,692	\$ 9,621
Debt return on Four Corners SCR deferral (Note 3)	—	14,955	15,865
Debt return on Ocotillo modernization project (Note 3)	—	23,366	26,121
Miscellaneous	556	40	148
Total other income	<u>\$ 5,888</u>	<u>\$ 43,053</u>	<u>\$ 51,755</u>
Other expense:			
Non-operating costs	\$ (15,579)	\$ (10,080)	\$ (10,659)
Miscellaneous	(10,529) (a)	(8,817)	(43,035) (a)
Total other expense	<u>\$ (26,108)</u>	<u>\$ (18,897)</u>	<u>\$ (53,694)</u>

- (a) The 2022 miscellaneous amount includes donations of \$7 million to the APS Foundation. The 2020 miscellaneous amount includes donations of approximately \$10 million to the APS Foundation and approximately \$25.2 million related to the CCT plan. See Note 3.

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 2023 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 2022, \$17 million for 2021 and \$19 million for 2020. The increase in net income is entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	December 31, 2022	December 31, 2021
Palo Verde sale leaseback property, plant and equipment, net of accumulated depreciation	\$ 90,296	\$ 94,166
Equity-Noncontrolling interests	111,229	115,260

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 \$324 million beginning in 2023, 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 2022 and 2021, APS was reimbursed \$15 million for each year, for prior year active union employee medical claims from the active union employee medical account. The account is invested primarily in fixed income securities. In accordance with the ratemaking treatment, APS has deferred the unrealized gains and losses (including credit losses) in other regulatory liabilities. Activities relating to active union employee medical account investments are included within the other special use funds in the table below.

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, 2022					
Investment Type:	Fair Value			Total Unrealized Gains	Total Unrealized Losses
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		
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	<u>\$ 1,073,410</u>	<u>\$ 347,231</u>	<u>\$ 1,420,641</u>	<u>\$ 337,994</u>	<u>\$ (69,091)</u>

(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.

December 31, 2021					
Investment Type:	Fair Value			Total Unrealized Gains	Total Unrealized Losses
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		
Equity securities	\$ 640,312	\$ 47,570	\$ 687,882	\$ 451,387	\$ —
Available for sale-fixed income securities	682,227	309,904	992,131 (a)	24,283	(4,063)
Other	(27,782)	936	(26,846) (b)	—	—
Total	<u>\$ 1,294,757</u>	<u>\$ 358,410</u>	<u>\$ 1,653,167</u>	<u>\$ 475,670</u>	<u>\$ (4,063)</u>

(a) As of December 31, 2021, the amortized cost basis of these available-for-sale investments is \$972 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
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
2020			
Realized gains	12,194	176	12,370
Realized losses	(5,553)	(15)	(5,568)
Proceeds from the sale of securities (a)	675,035	144,484	819,519

- (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, 2022, is as follows (dollars in thousands):

	Nuclear Decommissioning Trusts	Coal Reclamation Escrow Account	Active Union Employee Medical Account	Total
Less than one year	\$ 9,422	\$ 49,917	\$ 38,157	\$ 97,496
1 year – 5 years	181,640	36,484	143,878	362,002
5 years – 10 years	122,340	—	6,831	129,171
Greater than 10 years	268,941	4,027	—	272,968
Total	\$ 582,343	\$ 90,428	\$ 188,866	\$ 861,637

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

19. Changes in Accumulated Other Comprehensive Loss

The following table shows the changes in Pinnacle West's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component (dollars in thousands):

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Balance at December 31, 2020	\$ (60,725)		\$ (2,071)		\$ (62,796)
OCI (loss) before reclassifications	2,439		1,077		3,516
Amounts reclassified from accumulated other comprehensive loss	4,401	(a)	18	(b)	4,419
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)

- (a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 7.
- (b) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 15.

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		Derivative Instruments		Total
Balance at December 31, 2020	\$ (40,918)		\$ —		\$ (40,918)
OCI (loss) before reclassifications	2,043		(18)		2,025
Amounts reclassified from accumulated other comprehensive loss	3,995	(a)	18	(b)	4,013
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)

- (a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 7.
- (b) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 15.

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,		
	2022	2021	2020
Operating expenses	\$ 8,850	\$ 10,245	\$ 7,901
Other			
Equity in earnings of subsidiaries	500,042	628,916	566,147
Other expense	(4,725)	(4,919)	(4,586)
Total	495,317	623,997	561,561
Interest expense	18,861	10,672	14,021
Income before income taxes	467,606	603,080	539,639
Income tax benefit	(15,996)	(15,640)	(10,920)
Net income attributable to common shareholders	483,602	618,720	550,559
Other comprehensive income (loss) — attributable to common shareholders	23,426	7,935	(5,700)
Total comprehensive income — attributable to common shareholders	\$ 507,028	\$ 626,655	\$ 544,859

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,	
	2022	2021
ASSETS		
Current assets		
Cash and cash equivalents	\$ —	\$ 594
Accounts receivable	132,061	125,457
Income tax receivable	14,494	1,498
Other current assets	288	13
Total current assets	<u>146,843</u>	<u>127,562</u>
Investments and other assets		
Investments in subsidiaries	7,105,789	6,797,528
Deferred income taxes	1,521	19,520
Other assets	23,153	57,608
Total investments and other assets	<u>7,130,463</u>	<u>6,874,656</u>
TOTAL ASSETS	<u><u>\$ 7,277,306</u></u>	<u><u>\$ 7,002,218</u></u>
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	\$ 6,499	\$ 3,071
Accrued taxes	7,694	19,855
Common dividends payable	97,895	95,988
Short-term borrowings	15,720	13,300
Current maturities of long-term debt	—	150,000
Operating lease liabilities	117	107
Other current liabilities	14,637	14,684
Total current liabilities	<u>142,562</u>	<u>297,005</u>
Long-term debt less current maturities (Note 6)	<u>947,892</u>	<u>647,139</u>
Pension liabilities	8,218	14,537
Operating lease liabilities	1,459	1,576
Other	17,299	20,501
Total deferred credits and other	<u>26,976</u>	<u>36,614</u>
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
Common stock equity		
Common stock	2,719,735	2,696,342
Accumulated other comprehensive loss	(31,435)	(54,861)
Retained earnings	3,360,347	3,264,719
Total Pinnacle West Shareholders' equity	<u>6,048,647</u>	<u>5,906,200</u>
Noncontrolling interests	111,229	115,260
Total Equity	<u>6,159,876</u>	<u>6,021,460</u>
TOTAL LIABILITIES AND EQUITY	<u><u>\$ 7,277,306</u></u>	<u><u>\$ 7,002,218</u></u>

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,		
	2022	2021	2020
Cash flows from operating activities			
Net income	\$ 483,602	\$ 618,720	\$ 550,559
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of subsidiaries — net	(500,042)	(628,916)	(566,147)
Depreciation and amortization	76	93	76
Deferred income taxes	17,256	(11,381)	33,007
Accounts receivable	(8,535)	8,897	(7,903)
Accounts payable	3,431	(2,598)	(1,964)
Accrued taxes and income tax receivables — net	(25,157)	16,079	9,610
Dividends received from subsidiaries	385,800	376,500	357,500
Other	47,719	4,214	20,163
Net cash flow provided by operating activities	404,150	381,608	394,901
Cash flows from investing activities			
Investments in subsidiaries	(186,630)	(145,266)	(137,881)
Repayments of loans from subsidiaries	14,308	4,017	932
Advances of loans to subsidiaries	(3,308)	(12,256)	(7,261)
Net cash flow used for investing activities	(175,630)	(153,505)	(144,210)
Cash flows from financing activities			
Issuance of long-term debt	300,000	300,000	496,950
Short-term debt borrowings under revolving credit facility	—	—	211,690
Short-term debt repayments under revolving credit facility	—	(19,000)	(230,690)
Short-term borrowings and (repayments) — net	2,420	(136,700)	73,325
Dividends paid on common stock	(378,881)	(369,478)	(350,577)
Repayment of long-term debt	(150,000)	—	(450,000)
Common stock equity issuance and purchases — net	(2,653)	(2,350)	(1,389)
Net cash flow used for financing activities	(229,114)	(227,528)	(250,691)
Net decrease in cash and cash equivalents	(594)	575	—
Cash and cash equivalents at beginning of year	594	19	19
Cash and cash equivalents at end of year	\$ —	\$ 594	\$ 19

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, 2022. 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, 2022. 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, 2022, 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

None.

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 17, 2023 (the “2023 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 2023 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 2023 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth information as of December 31, 2022, with respect to the 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	1,340,572	—	864,533
Equity compensation plans not approved by security holders	—	—	—
Total	1,340,572	—	864,533

- (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 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 and the 2007 Plan. However, if an award under the 2012 Plan 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 and under which no new stock awards may be granted; (b) the 2012 Plan, as amended, which was approved by our shareholders at our 2012 annual meeting of shareholders and the first amendment to the 2012 Plan was approved by our shareholders at our 2017 annual meeting of shareholders and 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. 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 2023 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 2023 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	2022	2021
Audit Fees (1)	\$ 2,653,737	\$ 2,580,260
Audit-Related Fees (2)	498,167	333,905

- (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 and environmental, social and governance assurance readiness performed in 2022 and 2021.

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 2022 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
4.6(h)	Pinnacle West APS	Seventeenth Supplemental Indenture dated as of May 19, 2015	4.1 to Pinnacle West/APS May 14, 2015 Form 8-K Report, File Nos. 1-8962 and 1-4473	5/19/2015
4.6(i)	Pinnacle West APS	Eighteenth Supplemental Indenture dated as of November 6, 2015	4.1 to Pinnacle West/APS November 3, 2015 Form 8-K Report, File Nos. 1-8962 and 1-4473	11/6/2015
4.6(j)	Pinnacle West APS	Nineteenth Supplemental Indenture dated as of May 6, 2016	4.1 to Pinnacle West/APS May 3, 2016 Form 8-K Report, File Nos. 1-8962 and 1-4473	5/6/2016
4.6(k)	Pinnacle West APS	Twentieth Supplemental Indenture dated as of September 20, 2016	4.1 to Pinnacle West/APS September 15, 2016 Form 8-K Report, File Nos. 1-8962 and 1-4473	9/20/2016
4.6(l)	Pinnacle West APS	Twenty-First Supplemental Indenture dated as of September 11, 2017	4.1 to Pinnacle West/APS September 11, 2017 Form 8-K Report, File Nos. 1-8962 and 1-4473	9/11/2017

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
4.7	Pinnacle West	Second Amended and Restated Pinnacle West Capital Corporation Investors Advantage Plan dated as of June 23, 2004	4.4 to Pinnacle West's June 23, 2004 Form 8-K Report, File No. 1-8962	8/9/2004
4.7(a)	Pinnacle West	Third Amended and Restated Pinnacle West Capital Corporation Investors Advantage Plan dated as of November 25, 2008	4.1 to Pinnacle West's Form S-3 Registration Statement No. 333-155641, File No. 1-8962	11/25/2008
4.8	Pinnacle West	Agreement, dated March 29, 1988, relating to the filing of instruments defining the rights of holders of long-term debt not in excess of 10% of the Company's total assets	4.1 to Pinnacle West's 1987 Form 10-K Report, File No. 1-8962	3/30/1988
4.8(a)	Pinnacle West APS	Agreement, dated March 21, 1994, relating to the filing of instruments defining the rights of holders of APS long-term debt not in excess of 10% of APS's total assets	4.1 to APS's 1993 Form 10-K Report, File No. 1-4473	3/30/1994
4.9	Pinnacle West APS	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934		
10.1(1)	Pinnacle West APS	Two separate Decommissioning Trust Agreements (relating to PVGS Units 1 and 3, respectively), each dated July 1, 1991, between APS and Mellon Bank, N.A., as Decommissioning Trustee	10.2 to APS's September 30, 1991 Form 10-Q Report, File No. 1-4473	11/14/1991

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 West APS	Amended and Restated Decommissioning Trust Agreement (PVGS Unit 2) dated as of January 31, 1992, among APS, Mellon Bank, N.A., as Decommissioning Trustee, and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under two separate Trust Agreements, each with a separate Equity Participant, and as Lessor under two separate Facility Leases, each relating to an undivided interest in PVGS Unit 2	10.1 to Pinnacle West's 1991 Form 10-K Report, File No. 1-8962	3/26/1992

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 as of April 1, 2007	10.1.2h to Pinnacle West's 2007 Form 10-K Report, File No. 1-8962	2/27/2008
10.2(1) ^b	Pinnacle West APS	Arizona Public Service Company Deferred Compensation Plan, as restated, effective January 1, 1984, and the second and third amendments thereto, dated December 22, 1986, and December 23, 1987, respectively	10.4 to APS's 1988 Form 10-K Report, File No. 1-4473	3/8/1989
10.2(1)(a) ^b	Pinnacle West APS	Third Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993	10.3A to APS's 1993 Form 10-K Report, File No. 1-4473	3/30/1994
10.2(1)(b) ^b	Pinnacle West APS	Fourth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective as of May 1, 1993	10.2 to APS's September 30, 1994 Form 10-Q Report, File No. 1-4473	11/10/1994
10.2(1)(c) ^b	Pinnacle West APS	Fifth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective January 1, 1997	10.3A to APS's 1996 Form 10-K Report, File No. 1-4473	3/28/1997

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 West APS	Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company, Deferred Compensation Plan as amended and restated effective January 1, 1996	10.10A to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996
10.2(4)(a) ^b	Pinnacle West APS	First Amendment effective as of January 1, 1999, to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company, Deferred Compensation Plan	10.7A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2(4)(b) ^b	Pinnacle West APS	Second Amendment effective January 1, 2000 to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company, Deferred Compensation Plan	10.10A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000

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 APS	First Amendment to the Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan of 2005 (as amended and restated effective January 1, 2016)	10.3.2a to Pinnacle West/APS 2016 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2017
10.3(2)(b) ^b	Pinnacle West APS	Second Amendment to the Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan of 2005 (as amended and restated effective January 1, 2016)	10.3.2b to Pinnacle West/APS 2017 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/23/2018
10.4(1) ^b	Pinnacle West APS	Offer of Employment Letter dated July 19, 2018 between Pinnacle West and Robert E. Smith	10.4.5 to Pinnacle West/APS 2019 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/21/2020
10.4(2) ^b	Pinnacle West APS	Supplemental Agreement dated October 17, 2018 between Pinnacle West and Robert E. Smith	10.4.6 to Pinnacle West/APS 2019 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/21/2020
10.4(3) ^b	Pinnacle West APS	Discretionary Credit Award Agreement dated June 19, 2019 between Pinnacle West and Theodore Geisler	10.4.4 to Pinnacle West/APS 2020 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.4(4) ^b	Pinnacle West APS	Retention Agreement dated December 19, 2008 between APS and Maria Lacal	10.4.5a to Pinnacle West/APS 2021 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.4(5) ^b	Pinnacle West APS	First Amendment to the Retention Agreement dated May 24, 2011 between APS and Maria Lacal	10.4.5b to Pinnacle West/APS 2021 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.4(6)(a) ^b	Pinnacle West APS	Medical Retention Agreement dated October 31, 2014 between APS and Maria Lacal	10.4.6 to Pinnacle West/APS 2021 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.4(6)(b) ^b	Pinnacle West APS	Discretionary Credit Award Agreement dated October 31, 2014 between APS and Maria Lacal	10.4.7 to Pinnacle West/APS 2021 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.4(7) ^b	Pinnacle West APS	Discretionary Credit Award Agreement dated September 29, 2016 between APS and Maria Lacal	10.4.8 to Pinnacle West/APS 2021 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2021
10.4(8) ^b	Pinnacle West APS	Offer of Employment Letter dated May 19, 2022 between APS and Adam Heflin		
10.4(9) ^b	Pinnacle West APS	Discretionary Credit Award Agreement dated June 21, 2019 between APS and Jacob Tetlow		
10.4(10) ^b	Pinnacle West APS	First Amendment to Discretionary Credit Award Agreement dated February 21, 2021 between APS and Jacob Tetlow		
10.5(1) ^{bd}	Pinnacle West APS	Key Executive Employment and Severance Agreement between Pinnacle West and certain executive officers of Pinnacle West and its subsidiaries	10.77bd to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
10.5(1)(a) ^{bd}	Pinnacle West APS	Form of Amended and Restated Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.4 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File Nos. 1-8962 and 1-4473	11/6/2007
10.5(2) ^{bd}	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.3 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File Nos. 1-8962 and 1-4473	11/6/2007
10.5(3) ^{bd}	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.5.3 to Pinnacle West/APS 2009 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/19/2010
10.5(4) ^{bd}	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.5.4 to Pinnacle West/APS 2012 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/22/2013
10.5(5) ^{bd}	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.4 to Pinnacle West/APS June 30, 2021 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/5/2021

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.6(1) ^b	Pinnacle West	Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	Appendix B to the Proxy Statement for Pinnacle West's 2007 Annual Meeting of Shareholders, File No. 1-8962	4/20/2007
10.6(1)(a) ^b	Pinnacle West	First Amendment to the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.2 to Pinnacle West/APS April 18, 2007 Form 8-K Report, File No. 1-8962	4/20/2007
10.6(1)(b) ^{bd}	Pinnacle West APS	Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.3 to Pinnacle West/APS March 31, 2009 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/5/2009
10.6(1)(c) ^{bd}	Pinnacle West	Form of Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.1 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962	8/3/2010
10.6(1)(d) ^{bd}	Pinnacle West	Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.2 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962	8/3/2010
10.6(1)(e) ^{bd}	Pinnacle West	Form of Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.4 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File No. 1-8962	4/29/2011
10.6(1)(f) ^{bd}	Pinnacle West	Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.5 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File No. 1-8962	4/29/2011
10.6(1)(g) ^{bd}	Pinnacle West	Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan (Supplemental 2010 Award)	10.6 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File No. 1-8962	4/29/2011
10.6(2) ^b	Pinnacle West	Description of Annual Stock Grants to Non-Employee Directors	10.1 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File No. 1-8962	11/6/2007
10.6(3) ^b	Pinnacle West	Description of Annual Stock Grants to Non-Employee Directors	10.2 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-8962	8/7/2008
10.6(4) ^{bd}	Pinnacle West APS	Summary of 2023 Variable Incentive Plan and Officer Variable Incentive Plan		
10.6(5) ^b	Pinnacle West APS	Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	Appendix A to the Proxy Statement for Pinnacle West's 2012 Annual Meeting of Shareholders, File No. 1-8962	3/29/2012
10.6(5)(a) ^{bd}	Pinnacle West	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)(b) ^{bd}	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.2 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/3/2012

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.6(5)(c) ^{bd}	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.8c to Pinnacle West/APS 2013 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/21/2014
10.6(5)(d) ^{bd}	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.8d to Pinnacle West/APS 2013 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/21/2014
10.6(5)(e) ^{bd}	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.6e to Pinnacle West/APS 2015 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/19/2016
10.6(5)(f) ^{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)(g) ^{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)(h) ^{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)(i) ^{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)(j) ^{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)(k) ^{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)(l) ^{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)(m) ^{bd}	Pinnacle West APS	Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan	Appendix A to the Proxy Statement for Pinnacle West's 2021 Annual Meeting of Shareholders, File No. 1-8962	4/01/2021
10.6(5)(n) ^{bd}	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan	10.6.5n to Pinnacle West/APS 2020 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/25/2022
10.6(5)(o) ^{bd}	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan	10.6.5o to Pinnacle West/APS 2020 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/25/2022

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.6(5)(p) ^{bd}	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan	10.6.5p to Pinnacle West/APS 2020 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/25/2022
10.6(5)(q) ^{bd}	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2021 Long-Term Incentive Plan	10.6.5q to Pinnacle West/APS 2020 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/25/2022
10.6(5)(r) ^{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)(s) ^{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)(t) ^{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)(u) ^{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
10.6(5)(v) ^{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
10.7(1)	Pinnacle West APS	Indenture of Lease with Navajo Tribe of Indians, Four Corners Plant	5.01 to APS's Form S-7 Registration Statement, File No. 2-59644	9/1/1977
10.7(1)(a)	Pinnacle West APS	Supplemental and Additional Indenture of Lease, including amendments and supplements to original lease with Navajo Tribe of Indians, Four Corners Plant	5.02 to APS's Form S-7 Registration Statement, File No. 2-59644	9/1/1977
10.7(1)(b)	Pinnacle West APS	Amendment and Supplement No. 1 to Supplemental and Additional Indenture of Lease Four Corners, dated April 25, 1985	10.36 to Pinnacle West's Registration Statement on Form 8-B Report, File No. 1-89	7/25/1985
10.7(1)(c)	Pinnacle West APS	Amendment and Supplement No. 2 to Supplemental and Additional Indenture of Lease with the Navajo Nation dated March 7, 2011	10.1 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File Nos. 1-8962 and 1-4473	4/29/2011
10.7(1)(d)	Pinnacle West APS	Amendment and Supplement No. 3 to Supplemental and Additional Indenture of Lease with the Navajo Nation dated March 7, 2011	10.2 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File Nos. 1-8962 and 1-4473	4/29/2011
10.7(2)	Pinnacle West APS	Application and Grant of multi-party rights-of-way and easements, Four Corners Plant Site	5.04 to APS's Form S-7 Registration Statement, File No. 2-59644	9/1/1977
10.7(2)(a)	Pinnacle West APS	Application and Amendment No. 1 to Grant of multi-party rights-of-way and easements, Four Corners Site dated April 25, 1985	10.37 to Pinnacle West's Registration Statement on Form 8-B, File No. 1-8962	7/25/1985

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.7(3)	Pinnacle West APS	Application and Grant of APS rights- of-way and easements, Four Corners Site	5.05 to APS's Form S-7 Registration Statement, File No. 2-59644	9/1/1977
10.7(3)(a)	Pinnacle West APS	Application and Amendment No. 1 to Grant of APS rights-of-way and easements, Four Corners Site dated April 25, 1985	10.38 to Pinnacle West's Registration Statement on Form 8-B, File No. 1-8962	7/25/1985
10.7(4)	Pinnacle West APS	Four Corners Project Co-Tenancy Agreement, conformed copy up through and including Amendment No. 11, dated June 30, 2018, among APS, Public Service Company of New Mexico, SRP, Tucson Electric Power Company and Navajo Transitional Energy Company, LLC	10.7.4c to Pinnacle West/APS June 30, 2018 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/3/2018
10.7(4)(a)	Pinnacle West APS	Four Corners Project Co-Tenancy Agreement, conformed copy up through and including Amendment No. 13, dated June 25, 2021, among APS, Public Service Company of New Mexico, SRP, Tucson Electric Power Company and Navajo Transitional Energy Company, LLC	10.5 to Pinnacle West/APS June 30, 2021 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/5/2021
10.8(1)	Pinnacle West APS	Indenture of Lease, Navajo Units 1, 2, and 3	5(g) to APS's Form S-7 Registration Statement, File No. 2-36505	3/23/1970
10.8(2)	Pinnacle West APS	Application of Grant of rights-of-way and easements, Navajo Plant	5(h) to APS Form S-7 Registration Statement, File No. 2-36505	3/23/1970
10.8(3)	Pinnacle West APS	Water Service Contract Assignment with the United States Department of Interior, Bureau of Reclamation, Navajo Plant	5(l) to APS's Form S-7 Registration Statement, File No. 2-394442	3/16/1971
10.8(4)	Pinnacle West APS	Navajo Project Co-Tenancy Agreement dated as of March 23, 1976, and Supplement No. 1 thereto dated as of October 18, 1976; Amendment No. 1 dated as of July 5, 1988, and Amendment No. 2 dated as of June 14, 1996; Amendment No. 3 dated as of February 11, 1997; Amendment No. 4 dated as of January 21, 1997; Amendment No. 5 dated as of January 23, 1998; Amendment No. 6 dated as of July 31, 1998	10.107 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
10.8(5)	Pinnacle West APS	Navajo Project Participation Agreement dated as of September 30, 1969, and Amendment and Supplement No. 1 dated as of January 16, 1970, and Coordinating Committee Agreement No. 1 dated as of September 30, 1971	10.108 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.9(1)	Pinnacle West APS	ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles, and amendments 1-12 thereto	10.1 to APS's 1988 Form 10-K Report, File No. 1-4473	3/8/1989
10.9(1)(a)	Pinnacle West APS	Amendment No. 13, dated as of April 22, 1991, to ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso, 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, 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, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.9.1c to Pinnacle West/APS 2010 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/18/2011
10.9(1)(d)	Pinnacle West APS	Amendment No. 16, dated April 28, 2014, to ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.2 to Pinnacle West/APS March 31, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/2/2014
10.10(1)	Pinnacle West APS	Asset Purchase and Power Exchange Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990 and as of July 18, 1991	10.1 to APS's June 30, 1991 Form 10-Q Report, File No. 1-4473	8/8/1991
10.10(2)	Pinnacle West APS	Long-Term Power Transaction Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990, and as of July 8, 1991	10.2 to APS's June 30, 1991 Form 10-Q Report, File No. 1-4473	8/8/1991
10.10(2)(a)	Pinnacle West APS	Amendment No. 1 dated April 5, 1995 to the Long-Term Power Transaction Agreement and Asset Purchase and Power Exchange Agreement between PacifiCorp and APS	10.3 to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.10(3)	Pinnacle West APS	Restated Transmission Agreement between PacifiCorp and APS dated April 5, 1995	10.4 to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996
10.10(4)	Pinnacle West APS	Contract among PacifiCorp, APS and DOE Western Area Power Administration, Salt Lake Area Integrated Projects for Firm Transmission Service dated May 5, 1995	10.5 to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996
10.10(5)	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 APS	Term Loan Agreement dated as of February 26, 2019 among APS, as Borrower, SunTrust Bank, as Agent, SunTrust Bank, TD Bank, N.A., U.S. Bank National Association and The Bank of Nova Scotia, as Co-Syndication Agents and such institutions comprising the lenders party, thereto	10.1 to Pinnacle West/APS March 31, 2019 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/1/2019
10.11(2)	Pinnacle West	Amended and Restated Five-Year Credit Agreements dated as of May 28, 2021, among Pinnacle West, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto	10.1 to Pinnacle West/APS June 30, 2021 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/5/2021
10.11(3)	Pinnacle West APS	Amended and Restated Five-Year Credit Agreement dated as of May 28, 2021, 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 June 30, 2021 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/5/2021
10.11(4)	Pinnacle West APS	Five-Year Credit Agreement dated as of May 28, 2021, among APS, as Borrower, Barclays Bank PLC, as Agent, Co-Sustainability Structuring Agent and Issuing Bank, and the lenders and other parties thereto	10.3 to Pinnacle West/APS June 30, 2021 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/5/2021
10.12(1)	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)	Pinnacle West APS	Amendment No. 1, dated as of November 1, 1986, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.5 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8, File No. 1-4473	12/4/1986

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.12(1)(b)*	Pinnacle West APS	Amendment No. 2 dated as of June 1, 1987 to Facility Lease dated as of August 1, 1986 between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS's 1988 Form 10-K Report, File No. 1-4473	3/8/1989
10.12(1)(c)*	Pinnacle West APS	Amendment No. 3, dated as of March 17, 1993, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
10.12(1)(d)*	Pinnacle West APS	<u>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</u>	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)*	Pinnacle West APS	<u>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</u>	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 Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	4.13 to APS's Form 18 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report, File No. 1-4473	8/24/1987

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.12(2)(b)	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.4 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
10.12(2)(c)	Pinnacle West APS	Amendment No. 3, dated July 10, 2014, to Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to the First National Bank of Boston, as Lessor, and APS, as Lessee	10.2 to Pinnacle West/APS June 30, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473	7/31/2014
10.12(2)(d)	Pinnacle West APS	Amendment No. 4, dated April 1, 2021, to Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to the First National Bank of Boston, as Lessor, and APS, as Lessee	10.1 to Pinnacle West/APS March 31, 2021 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/5/2021
10.13(1)	Pinnacle West APS	Agreement between Pinnacle West Energy Corporation and APS for Transportation and Treatment of Effluent by and between Pinnacle West Energy Corporation and APS dated as of the 10th day of April, 2001	10.102 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/16/2005
10.13(2)	Pinnacle West APS	Agreement for the Transfer and Use of Wastewater and Effluent by and between APS, SRP and PWE dated June 1, 2001	10.103 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/16/2005
10.13(3)	Pinnacle West APS	Agreement for the Sale and Purchase of Wastewater Effluent dated November 13, 2000, by and between the City of Tolleson, Arizona, APS and SRP	10.104 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/16/2005
10.13(4)	Pinnacle West APS	Operating Agreement for the Co-Ownership of Wastewater Effluent dated November 16, 2000 by and between APS and SRP	10.105 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/16/2005
10.13(5)	Pinnacle West APS	Municipal Effluent Purchase and Sale Agreement dated April 29, 2010, by and between City of Phoenix, City of Mesa, City of Tempe, City of Scottsdale, City of Glendale, APS and SRP	10.1 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/6/2010
10.14(1)	Pinnacle West APS	Contract, dated July 21, 1984, with DOE providing for the disposal of nuclear fuel and/or high-level radioactive waste, ANPP	10.31 to Pinnacle West's Form S-14 Registration Statement, File No. 2-96386	3/13/1985
10.15(1)	Pinnacle West APS	Territorial Agreement between APS and SRP	10.1 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5/15/1998

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.15(2)	Pinnacle West APS	Power Coordination Agreement between APS and SRP	10.2 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5/15/1998
10.15(3)	Pinnacle West APS	Memorandum of Agreement between APS and SRP	10.3 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5/15/1998
10.15(3)(a)	Pinnacle West APS	Addendum to Memorandum of Agreement between APS and SRP dated as of May 19, 1998	10.2 to APS's May 19, 1998 Form 8-K Report, File No. 1-4473	6/26/1998
10.16	Pinnacle West APS	Purchase and Sale Agreement dated November 8, 2010 by and between SCE and APS	10.1 to Pinnacle West/APS November 8, 2010 Form 8-K Report, File Nos. 1-8962 and 1-4473	11/8/2010
10.17	Pinnacle West APS	Proposed Settlement Agreement dated January 6, 2012 by and among APS and certain parties to its retail rate case (approved by ACC Order No. 73183)	10.17 to Pinnacle West/APS 2011 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2012
10.18	Pinnacle West APS	Proposed Settlement Agreement dated March 27, 2017 by and among APS and certain parties to its retail rate case (approved by ACC Order No. 76295)	10.1 to Pinnacle West/APS March 31, 2017 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/2/2017
10.19	Pinnacle West	Purchase and Sale Agreement, dated June 29, 2018, by and between Navajo Transitional Energy Company, LLC and 4CA	10.2 to Pinnacle West/APS June 30, 2018 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/3/2018
21.1	Pinnacle West	Subsidiaries of Pinnacle West		
23.1	Pinnacle West	Consent of Deloitte & Touche LLP		
23.2	APS	Consent of Deloitte & Touche LLP		
31.1	Pinnacle West	Certificate of Jeffrey B. Guldner, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended		
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*	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		

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
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		
99.1 ^c	Pinnacle West APS	Participation Agreement, dated as of August 1, 1986, among PVGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.1 to APS's September 30, 1992 Form 10-Q Report, File No. 1-4473	11/9/1992
99.1(a) ^c	Pinnacle West APS	Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1, 1986, among PVGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	10.8 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1, on December 3, 1986 Form 8, File No. 1-4473	12/4/1986
99.1(b) ^c	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of August 1, 1986, among PVGS Funding Corp., Inc., PVGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.4 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.2 ^c	Pinnacle West APS	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to APS's Form 18 Registration Statement, File No. 33-9480	10/24/1986

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
99.2(a) ^c	Pinnacle West APS	Supplemental Indenture No. 1, dated as of November 1, 1986 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.6 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8, File No. 1-4473	12/4/1986
99.2(b) ^c	Pinnacle West APS	Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Lease Indenture Trustee	4.4 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.3 ^c	Pinnacle West APS	Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.3 to APS's Form 18 Registration Statement, File No. 33-9480	10/24/1986
99.3(a) ^c	Pinnacle West APS	Amendment No. 1, dated as of November 1, 1986, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.10 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 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

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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
99.6(a)	Pinnacle West APS	Amendment No. 1, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.7 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.7 ^c	Pinnacle West APS	Indemnity Agreement dated as of March 17, 1993 by APS	28.3 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.8	Pinnacle West APS	Extension Letter, dated as of August 13, 1987, from the signatories of the Participation Agreement to Chemical Bank	28.20 to APS's Form 18 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report, File No. 1-4473	8/10/1987
99.9	Pinnacle West APS	ACC Order, Decision No. 61969, dated September 29, 1999, including the Retail Electric Competition Rules	10.2 to APS's September 30, 1999 Form 10-Q Report, File No. 1-4473	11/15/1999
99.10	Pinnacle West	Purchase Agreement by and among Pinnacle West Energy Corporation and GenWest, L.L.C. and Nevada Power Company, dated June 21, 2005	99.5 to Pinnacle West/APS June 30, 2005 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/9/2005
101.SCH	Pinnacle West APS	XBRL Taxonomy Extension Schema Document		
101.CAL	Pinnacle West APS	XBRL Taxonomy Extension Calculation Linkbase Document		
101.LAB	Pinnacle West APS	XBRL Taxonomy Extension Label Linkbase Document		
101.PRE	Pinnacle West APS	XBRL Taxonomy Extension Presentation Linkbase Document		
101.DEF	Pinnacle West APS	XBRL Taxonomy Definition Linkbase Document		

^aReports filed under File No. 1-4473 and 1-8962 were filed in the office of the SEC located in Washington, D.C.

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

^cAn 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.

^dAdditional 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.

^eFurnished 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, 2023

/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
<u>/s/ Jeffrey B. Guldner</u> (Jeffrey B. Guldner, Chairman of the Board of Directors, President and Chief Executive Officer)	Principal Executive Officer and Director	February 27, 2023
<u>/s/ Andrew Cooper</u> (Andrew Cooper, Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 27, 2023
<u>/s/ Elizabeth A. Blankenship</u> (Elizabeth A. Blankenship, Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 27, 2023

/s/ Glynis A. Bryan (Glynis A. Bryan)	Director	February 27, 2023
/s/ Richard P. Fox (Richard P. Fox)	Director	February 27, 2023
/s/ Dale E. Klein, Ph. D. (Dale E. Klein, Ph.D.)	Director	February 27, 2023
/s/ Gonzalo A. de la Melena, Jr. (Gonzalo A. de la Melena, Jr.)	Director	February 27, 2023
/s/ Kathryn L. Munro (Kathryn L. Munro)	Director	February 27, 2023
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	February 27, 2023
/s/ Paula J. Sims (Paula J. Sims)	Director	February 27, 2023
/s/ William H. Spence (William H. Spence)	Director	February 27, 2023
/s/ James E. Trevathan, Jr. (James E. Trevathan, Jr.)	Director	February 27, 2023
/s/ David P. Wagener (David P. Wagener)	Director	February 27, 2023

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, 2023

/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
<u>/s/ Jeffrey B. Guldner</u> (Jeffrey B. Guldner, Chairman of the Board of Directors and Chief Executive Officer)	Principal Executive Officer and Director	February 27, 2023
<u>/s/ Andrew Cooper</u> (Andrew Cooper, Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 27, 2023
<u>/s/ Elizabeth A. Blankenship</u> (Elizabeth A. Blankenship Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 27, 2023

/s/ Glynis A. Bryan (Glynis A. Bryan)	Director	February 27, 2023
/s/ Richard P. Fox (Richard P. Fox)	Director	February 27, 2023
/s/ Dale E. Klein, Ph. D. (Dale E. Klein, Ph.D.)	Director	February 27, 2023
/s/ Gonzalo A. de la Melena, Jr. (Gonzalo A. de la Melena, Jr.)	Director	February 27, 2023
/s/ Kathryn L. Munro (Kathryn L. Munro)	Director	February 27, 2023
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	February 27, 2023
/s/ Paula J. Sims (Paula J. Sims)	Director	February 27, 2023
/s/ William H. Spence (William H. Spence)	Director	February 27, 2023
/s/ James E. Trevathan, Jr. (James E. Trevathan, Jr.)	Director	February 27, 2023
/s/ David P. Wagener (David P. Wagener)	Director	February 27, 2023

**DESCRIPTION OF THE REGISTRANTS' SECURITIES
REGISTERED PURSUANT TO SECTION 12 OF THE
SECURITIES EXCHANGE ACT OF 1934**

Pinnacle West Capital Corporation ("Pinnacle West")

The following description of Pinnacle West's securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 is a summary and does not purport to be complete. The description is subject to, and qualified in its entirety by express reference to, the provisions of Pinnacle West's articles of incorporation and bylaws. Copies of the articles of incorporation and bylaws have been filed by Pinnacle West with the Securities and Exchange Commission and are exhibits to our Annual Report on Form 10-K to which this Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 is an exhibit. When we use the terms "we," "us," "our," and like terms in this description of Pinnacle West securities registered pursuant to Section 12 of the Securities Exchange Act of 1934, we are referring to Pinnacle West.

Authorized Shares

Under our articles of incorporation, we have the authority to issue 150,000,000 shares of common stock. Our Board of Directors has significant discretion to determine the timing, circumstances and purposes for which the authorized shares of common stock available for issuance under our articles of incorporation may be issued, including in the context of acquisitions or other strategic transactions.

Dividends

Subject to any preferential rights of any series of preferred stock, holders of shares of common stock will be entitled to receive dividends on the stock out of assets legally available for distribution when, as and if declared by our Board of Directors. The payment of dividends on the common stock will be a business decision to be made by our Board of Directors from time to time based upon results of our operations and our financial condition and any other factors that our Board of Directors considers relevant. Payment of dividends on the common stock may be restricted by loan agreements, indentures and other transactions entered into by us from time to time. Any material contractual restrictions on dividend payments that exist at the time of any offer of any common stock will be described in the applicable offering documents. In addition, our principal income consists of dividends paid to us by our subsidiaries, primarily Arizona Public Service Company ("APS"). APS's ability to pay dividends could be limited or restricted from time to time by loan agreements, indentures and other transactions or by law or regulatory authorities.

Voting Rights

Holders of common stock are entitled to one vote per share on all matters voted on generally by the shareholders. Arizona law provides for cumulative voting for the election of directors. As a result, any shareholder may cumulate his or her votes by casting them all for any one director nominee or by distributing them among two or more nominees. This may make it easier for minority shareholders to elect a director.

Liquidation Rights

Subject to any preferential rights of any series of preferred stock, holders of shares of common stock are entitled to share ratably in our assets legally available for distribution to our shareholders in the event of our liquidation, dissolution or winding up.

Absence of Other Rights or Assessments

Holders of common stock have no preferential, preemptive, conversion or exchange rights. When issued in accordance with our articles of incorporation and law, shares of our common stock will be fully paid and not liable to further calls or assessment by us.

Transfer Agent and Registrar

Computershare Trust Company, N. A. is the transfer agent and registrar for the common stock.

Preferred Stock

Our Board of Directors has the authority, without any further action by our shareholders, to issue from time to time up to 10,000,000 shares of preferred stock, in one or more series, and to fix the designations, preferences, rights, qualifications, limitations and restrictions thereof, including voting rights, dividend rights, dividend rates, conversion rights, terms of redemption, redemption prices, liquidation preferences and the number of shares constituting any series. The issuance of preferred stock with voting rights could have an adverse effect on the voting power of holders of common stock by increasing the number of outstanding shares having voting rights. In addition, if our Board of Directors authorizes preferred stock with conversion rights, the number of shares of common stock outstanding could potentially be increased up to the authorized amount. The issuance of preferred stock could decrease the amount of earnings and assets available for distribution to holders of common stock. Any such issuance could also have the effect of delaying, deterring or preventing a change in control of us.

Certain Anti-takeover Effects

General. Certain provisions of our articles of incorporation, our bylaws, and Arizona law may have an anti-takeover effect and may delay or prevent a tender offer or other acquisition transaction that a shareholder might consider to be in his or her best interest. The summary of the provisions of our articles, bylaws and Arizona law set forth below does not purport to be complete and is qualified in its entirety by reference to our articles, bylaws and Arizona law.

Business Combinations. Arizona law and our bylaws restrict a wide range of transactions (collectively, "business combinations") between us or, in certain cases, one of our subsidiaries, and an interested shareholder. An "interested shareholder" is:

- any person who beneficially owns, directly or indirectly, 10% or more of our outstanding voting power, or
- any of our affiliates or associates who at any time within the prior three years was such a beneficial owner.

The statute defines "business combinations" to include, with certain exceptions:

- mergers, consolidations and share exchanges with an interested shareholder;
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- any sale, lease, exchange, mortgage, pledge, transfer or other disposition of assets to an interested shareholder, representing 10% or more of (i) the aggregate market value of all of our consolidated assets as of the end of the most recent fiscal quarter, (ii) the aggregate market value of all our outstanding shares, or (iii) our consolidated revenues or net income for the four most recent fiscal quarters;
- the issuance or transfer of shares of stock having an aggregate market value of 5% or more of the aggregate market value of all of our outstanding shares to an interested shareholder;
- the adoption of a plan or proposal for our liquidation or dissolution or reincorporation in another state or jurisdiction pursuant to an agreement or arrangement with an interested shareholder;
- corporate actions, such as stock splits and stock dividends, and other transactions, in each case resulting in an increase in the proportionate share of the outstanding shares of any series or class of stock of us or any of our subsidiaries owned by an interested shareholder; and
- the receipt by an interested shareholder of the benefit (other than proportionately as a shareholder) of any loans, advances, guarantees, pledges or other financial assistance or any tax credits or other tax advantages provided by or through us or any of our subsidiaries.

Arizona law and our bylaws provide that, subject to certain exceptions, we may not engage in a business combination with an interested shareholder or authorize one of our subsidiaries to do so, for a period of three years after the date on which the interested shareholder first acquired the shares that qualify such person as an interested shareholder (the "share acquisition date"), unless either the business combination or the interested shareholder's acquisition of shares on the share acquisition date is approved by a committee of our Board of Directors (comprised solely of disinterested directors or other disinterested persons) prior to the interested shareholder's share acquisition date.

In addition, after such three-year period, Arizona law and our bylaws prohibit us from engaging in any business combination with an interested shareholder, subject to certain exceptions, unless:

- the business combination or acquisition of shares by the interested shareholder on the share acquisition date was approved by our Board of Directors prior to the share acquisition date;
- the business combination is approved by holders of a majority of our outstanding shares (excluding shares beneficially owned by the interested shareholder) at a meeting called after such three-year period; or
- the business combination satisfies specified price and other requirements.

Anti-Greenmail Provisions. Arizona law and our bylaws prohibit us from purchasing any shares of our voting stock from any beneficial owner (or group of beneficial owners acting together) of more than 5% of the voting power of our outstanding shares at a price per share in excess of the average closing sale price during the 30 trading days preceding the purchase or if the person or persons have commenced a tender offer or announced an intention to seek control of us, during the 30 trading days prior to the commencement of the tender offer or the making of the announcement, if the 5% beneficial

owner has beneficially owned the shares to be purchased for a period of less than three years, unless:

- holders of a majority of our voting power (excluding shares held by the 5% beneficial owner or by any of our officers and directors) approve the purchase; or
- we make the repurchase offer available to all holders of the class or series of securities to be purchased and to all holders of other securities convertible into that class or series.

Control Share Acquisition Statute. Under Arizona law, a control share acquisition is an acquisition, subject to certain exceptions, by a beneficial owner that would result in the owner having a new range of voting power within any of the following ranges: (i) at least 20% but less than 33¹/₃%; (ii) at least 33¹/₃% but less than or equal to 50%; or (iii) more than 50%. Through a provision in our bylaws, we have opted out of the Arizona statutory provisions regulating control share acquisitions. As a result, potential acquirors are not subject to the limitations imposed by that statute.

Special Meetings of Shareholders. Our bylaws provide that, except as required by law, special meetings of shareholders may be called by a majority of our Board of Directors, the Chairman of the Board, the President, or shareholders who have continuously held of record for at least one year Net Long Shares (as described in Section 2.02 of the bylaws) in the aggregate at least 15% of the voting power of the outstanding capital stock of Pinnacle West ("Special Meeting Requesting Shareholders"). Special Meeting Requesting Shareholders must meet certain qualifications and must submit a written request to the Corporate Secretary, containing the information required by our bylaws. A request for a special meeting made by Special Meeting Requesting Shareholders may be rejected if: (1) a meeting of shareholders that included an identical or substantially similar item of business, as determined in good faith by our Board of Directors, was held not more than 90 days before the Corporate Secretary received the request; (2) our Board of Directors has called or calls for a meeting of shareholders to be held within 90 days after the Corporate Secretary receives the request and our Board of Directors determines in good faith that the business to be conducted at such meeting includes similar business to that stated in the request; or (3) the request relates to an item of business that is not a proper subject for shareholder action under, or involves a

Election and Removal of Directors. Each member of our Board of Directors is elected annually to hold office until the next annual meeting of the shareholders or until his or her earlier death, resignation or removal or until his or her successor is duly elected and qualified.

Our bylaws provide that any director or the entire Board of Directors may be removed by vote of the shareholders with or without cause, but only at a special meeting called for that purpose, if the votes cast in favor of such removal exceed the votes cast against such removal. However, if less than the entire Board of Directors is to be removed, no one director may be removed if the votes cast against the director's removal would be sufficient to elect the director if then cumulatively voted at an election of directors.

Our bylaws provide that a director in an uncontested election who receives a greater number of votes cast "withheld" for his or her election than "for" such election must tender his or her resignation to the Corporate Governance Committee of our Board of Directors for

consideration. The Corporate Governance Committee will evaluate the director's tendered resignation, taking into account the best interest of Pinnacle West and its shareholders and will recommend to our Board of Directors whether to accept or reject the resignation. Any director tendering a resignation pursuant to this provision of our bylaws will not participate in any committee or Board of Director consideration of his or her resignation.

Our bylaws grant our Board of Directors the exclusive power to increase the size of our Board of Directors. Any such increase in the size of our Board of Directors, and the filling of any vacancy created thereby, require action by a majority of the whole membership of our Board of Directors as comprised immediately before such increase.

Shareholder Proposals and Director Nominations. A shareholder can submit shareholder proposals and nominate candidates for election to our Board of Directors in connection with our annual meeting if he or she follows the advance notice and other relevant provisions set forth in our bylaws. With respect to director nominations at an annual meeting not included in our proxy materials, shareholders must satisfy the provisions set forth in our bylaws and submit written notice to the Corporate Secretary at least 180 days prior to the date of the meeting. With respect to director nominations at an annual meeting to be included in our proxy materials, shareholders must satisfy the provisions set forth in our bylaws and submit such nomination to the Corporate Secretary not fewer than 120 nor more than 150 days prior to the first anniversary of the date that we mailed our proxy statement for the prior year's annual meeting of shareholders. With respect to shareholder proposals to bring other business before the annual meeting, shareholders must submit a written notice to the Corporate Secretary not fewer than 90 nor more than 120 days prior to the first anniversary of the date of our previous year's annual meeting of shareholders. However, if we have changed the date of the annual meeting by more than 30 days from the date of the previous year's annual meeting, the written notice must be submitted no earlier than 120 days before the annual meeting and not later than 90 days before the annual meeting or ten days after the day we make public the date of the annual meeting.

A shareholder must also comply with all applicable laws in proposing business to be conducted and in nominating directors. The notice provisions of the bylaws do not affect rights of shareholders to request inclusion of proposals in our proxy statement pursuant to Rule 14a-8 of the Exchange Act.

Amendment to Articles of Incorporation and Bylaws. Both the Board of Directors and the shareholders must approve amendments to an Arizona corporation's articles of incorporation, except that the Board of Directors may adopt specified ministerial amendments without shareholder approval. Unless the articles of incorporation, Arizona law or the Board of Directors would require a greater vote or unless the articles of incorporation or Arizona law would require a different quorum, the vote required by each voting group allowed or required to vote on the amendment would be:

- a majority of the votes entitled to be cast by the voting group, if the amendment would create dissenters' rights for that voting group; and
 - in any other case, if a quorum is present in person or by proxy consisting of a majority of the votes entitled to be cast on the matter by the voting group, the votes cast by the voting group in favor of the amendment must exceed the votes cast against the amendment by the voting group.
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The Board of Directors may amend or repeal the corporation's bylaws unless either: (i) the articles or applicable law reserves this power exclusively to shareholders in whole or in part or (ii) the shareholders in amending or repealing a particular bylaw provide expressly that the Board may not amend or repeal that bylaw. An Arizona corporation's shareholders may amend or repeal the corporation's bylaws even though they may also be amended or repealed by the Board of Directors. Our bylaws may not be amended or repealed without the vote of a majority of the Board of Directors then in office or the affirmative vote of a majority of votes cast on the matter at a meeting of shareholders.

Issuance of Additional Shares. Our Board of Directors has the ability 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. See the discussion above under the headings "Authorized Shares" and "Preferred Stock."

Arizona Public Service Company (“APS”)

The following description of APS’s securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 is a summary and does not purport to be complete. The description is subject to, and qualified in its entirety by express reference to, the provisions of APS’s articles of incorporation and bylaws. Copies of the articles of incorporation and bylaws have been filed by APS with the Securities and Exchange Commission and are exhibits to our Annual Report on Form 10-K to which this Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 is an exhibit. When we use the terms "we," "us," "our," and like terms in this description of APS securities registered pursuant to Section 12 of the Securities Exchange Act of 1934, we are referring to APS.

General

The general terms and provisions of our common stock are summarized below. All of our outstanding common stock is held by Pinnacle West and we have no preferred stock outstanding. However, subject to certain limitations, our Board of Directors has the authority, without any further action by our shareholders, to issue from time to time shares of preferred stock, in one or more series and to fix the designations, preferences, rights, qualifications, limitations and restrictions thereof.

Authorized Shares

Under our articles of incorporation, we have the authority to issue 100,000,000 shares of common stock, par value \$2.50 per share.

Dividends

Subject to any preferential rights of any series of preferred stock, holders of shares of common stock will be entitled to receive dividends on the stock out of assets legally available for distribution when, as and if authorized and declared by our Board of Directors. The payment of dividends on the common stock will be a business decision to be made by our Board of Directors from time to time based upon results of our operations and our financial condition and any other factors as our Board of Directors considers relevant. Payment of dividends on the common stock may be restricted by loan agreements, indentures and other transactions entered into by us from time to time. An Arizona Corporation Commission (“ACC”) order requires APS to maintain a common equity ratio of at least 42% and does not allow APS to pay dividends if the payment would reduce its common equity below that threshold. As defined in the ACC order, the common equity ratio is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt.

Voting Rights

Except as specified below, holders of common stock and preferred stock are entitled to one vote for each share held of record. Arizona law provides for cumulative voting for the election of directors. If six or more quarterly dividends accrued thereon shall not have been paid with respect to any outstanding preferred stock, the holders of such preferred stock will

have the right to elect the lesser of six directors or one-fourth of the total number of members of the Board of Directors at the time, in addition to their other voting rights. The preferred stock will also have special voting rights in matters involving the preferences or privileges of the preferred stock and certain extraordinary corporate occurrences.

Liquidation Rights

Subject to any preferential rights of any series of preferred stock, holders of shares of common stock are entitled to share ratably in our assets legally available for distribution to our shareholders in the event of our liquidation, dissolution or winding up.

Pre-emptive Rights

The holders of common stock have no pre-emptive rights to subscribe for other shares except with respect to an offering of additional common stock, or securities convertible into common stock, for money, other than by (a) a public offering of all of such shares, (b) an offering of all of such shares to or through underwriters or investment bankers who shall have agreed promptly to make a public offering of such shares, or (c) an offering of all such shares to our stockholders, our employees or our customers.

Miscellaneous

Outstanding shares of our common stock are fully paid and not liable to further calls or assessment by us.



Jeff Guldner

Chairman and Chief Executive Officer

May 19, 2022

Adam Heflin

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Adam-

I am pleased to extend to you this offer to become the Executive Vice President and Chief Nuclear Officer for Arizona Public Service Company. The detail of our proposal is included in Attachment A.

If you agree with the terms of our offer of employment as described herein, please sign as requested below.

Adam, I am confident that this will be a challenging and rewarding opportunity for you. I am excited about the prospect of you joining our team and we will do all that we can to ensure a smooth transition for you. I look forward to your contributions to our organization.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Jeff Guldner

Signing this letter indicates your acceptance of the terms of this offer.

Acceptance: /s/ Adam C. Heflin Date: 5/19/2022

Attachment A

A starting annual base salary of \$700,000

Hiring incentive of \$500,000 payable during the first two weeks of your employment. This one-time hiring incentive is intended to replace any relocation expenses including, without limitation, the costs associated with any sale or purchase of real estate, departure and startup costs, temporary living, transportation costs associated with the relocation, and any additional miscellaneous costs you might incur related to relocation. If, prior to your two-year anniversary date, you resign for any reason or your employment is terminated for cause, you shall immediately repay to the Company the full amount of this hiring incentive. For purposes of this offer letter, "terminated for cause" means any act or omission that could result in disciplinary action pursuant to applicable laws or Company policies and procedures. The Company shall determine, in its sole discretion, whether cause for discipline exists.

4 weeks of vacation annually

Vehicle allowance of \$10,000 per year

Financial planning reimbursement: \$7,500 first year and \$3,750 each subsequent year

Eligibility to participate in the officer annual incentive plan with target payment for 2022 of 75% and up to a maximum of 150% of annual base salary. Annual incentive payments are dependent on company and business unit performance and are generally paid during the first quarter of the subsequent year. Annual incentive payment for 2022 will be prorated based on the amount of time employed during 2022.

Long-Term Stock Based Compensation: Subject to Human Resources Committee (HRC) approval at the June 21, 2022 meeting, you will receive a long-term incentive award valued at \$1,200,000 to be granted to you effective upon your hire date and based upon the closing stock price on such date. The details of this award are as follows:

- Approximately 70% of the total award will be Performance Shares with a three-year performance period of January 1, 2022 through December 31, 2024
- Approximately 30% of the total award will be Restricted Stock Units that vest equally over a four-year period with your first vesting on February 20, 2023

These awards will vest subject to your continued employment through the applicable vesting date and in all events will be subject to the terms and conditions of the plan and the applicable award agreement.

- Additional one-time Restricted Stock Unit (RSU) Grant: Subject to HRC approval at the June 21, 2022 meeting, you will receive a one-time RSU grant valued at \$1,000,000 to be granted to you effective upon your hire date and based upon the closing stock price on such date. This award will vest equally over a four-year period with your first vesting on February 20, 2023 and subject to your continued employment through the applicable vesting date. In all events, this award will be subject to the terms and conditions of the plan and the applicable award agreement.

Eligibility to participate in the Supplemental Executive Benefit Retirement Plan (SEBRP). The SEBRP is structured as a cash balance plan to which the company contributes a percent of your base and annual incentive compensation as follow:

<u>Age</u>	<u>Percent of Monthly Compensation Contribution</u>
40-44	10%
45-49	12%
50-54	15%
55 and over	18%

Eligibility to participate in the company's 401(k) plan. After six months of employment, you will become eligible for the company matching contribution of 75 cents for every dollar you contribute, up to 6% of your compensation.

Eligibility to participate in the Deferred Compensation Plan (DCP). The DCP provides you with the opportunity to defer part of your compensation on a pre-tax basis. The deferred amount also earns interest. The Company sets the interest amount each calendar year. We provide officers with Key Executive Employment & Severance Agreements for change of control purposes. In the event of payment under this agreement, you would receive 2.99 times base salary and annual incentive as described in the agreement.

If you enroll in the company's benefit program within the first 30 days of employment, your medical, dental, and life insurance will be effective of your one-month anniversary date of employment. Medical and dental plan premiums are on a pre-tax basis.

All items of compensation, and all benefits, that are provided pursuant to a compensation or benefit plan or agreement will be subject to the terms and provisions of the relevant plan for agreement and, in all cases, the Company reserves the right to modify, amend, suspend, or terminate the applicable plan or agreement. All items of compensation will be subject to normal Federal and State withholding and taxation.

Your employment is "at will" which means that either you or the Company may terminate your employment at any time for any reason with or without notice.

You represent that you have full authority to execute this offer letter and that neither executing this letter or providing services to the Company or its affiliates will constitute a breach of any agreement that you may have with any other party.

This offer is contingent upon successful completion of a pre-employment medical screening and background check.

DISCRETIONARY CREDIT AWARD AGREEMENT

This Discretionary Credit Award Agreement (the “Agreement”) is entered into by and between Arizona Public Service Company (“APS”) and Jacob Tetlow (“Employee”).

1. **Purpose.** Section 3.9 of the Deferred Compensation Plan of 2005 for Employees of Pinnacle West Capital Corporation and Affiliates (the “Deferred Compensation Plan”) allows APS to award Discretionary Credits in such amounts and subject to such terms and conditions as APS deems appropriate. The purpose of this Agreement is to award Discretionary Credits to Employee subject to the terms and conditions set forth below.

2. **Definitions.** A number of key terms, with specialized meanings, are used throughout this Agreement. These key terms are identified by the capitalization of the initial letter of each word or phrase even when the word or phrase does not begin a sentence. Each of these key terms will be given the meaning ascribed to it in the Deferred Compensation Plan unless the term is defined in this Agreement. Whenever these key terms are used, they will be given the defined meaning unless a clearly different meaning is required by the context.

3. **Discretionary Credits.** Five Discretionary Credits in the aggregate amount of \$300,000 will be allocated to a Discretionary Credit Account (the “Discretionary Credit Account”) established for the benefit of Employee pursuant to Section 3.9 of the Deferred Compensation Plan. The Discretionary Credit Account shall be credited with: (i) \$100,000 on July 1, 2019; and (ii) \$50,000 on each of January 1, 2020 through January 1, 2023 provided that the Employee remains employed with APS on each such crediting date and demonstrates sustained competent performance of his assigned job responsibilities.

4. **Interest.** The Discretionary Credit Account shall be credited with interest in accordance with Section 3.5 of the Deferred Compensation Plan.

5. **Vesting.** The Discretionary Credit Account vests on December 31, 2024. If Employee Separates from Service prior to December 31, 2024, the amounts allocated to the Discretionary Credit Account will be forfeited; provided, however, that if Employee’s employment with APS is involuntarily terminated by APS without Cause, Employee dies or Employee becomes Disabled prior to December 31, 2024, all amounts previously credited to the Discretionary Credit Account will be fully vested as of the date of the termination by APS without Cause, death or Disability as applicable. For purposes of this document, “Disability” shall have the meaning ascribed to it in the Pinnacle West Capital Corporation Long-Term Disability Plan. For purposes of this document, “Cause” means any act or omission that could result in disciplinary action pursuant to applicable laws or APS policies and procedures, as determined in the sole discretion of APS. The determination of whether “Cause” exists shall be made by APS, in its sole and absolute discretion, in accordance with its personnel policies and procedures.

6. **Payment of Discretionary Credits.**

(a) **General Rule.** Except as otherwise provided below in this Section 6, Employee’s vested interest in his Discretionary Credit Account will be paid to Employee in substantially equal installments over a period of approximately five years following Employee’s Separation from Service with the first installment payment to be made within 30 days following Employee’s Separation from Service and each subsequent installment payment shall be made on the next four anniversaries of the first payment date, unless Employee is a Specified Employee on the date of his Separation from Service. If Employee is a Specified Employee on the date of his Separation from Service, the first installment payment shall be paid within 30 days following

the first day of the seventh month following Employee's Separation from Service and each subsequent installment payment shall be made on the next four anniversaries of the first payment date. The Discretionary Credit Account may not be distributed as a Short-Term Payout or due to an Unforeseeable Financial Emergency.

(b) **Disability.** If Employee becomes Disabled prior to his Separation from Service and if such Disability occurs prior to December 31, 2024, Employee shall receive a single lump sum payment of Employee's vested interest in his Discretionary Credit Account on the first business day following December 31, 2024 as long as the Disability constitutes a "disability" as defined in Section 409A of the Code. If the Disability does not constitute a "disability" as defined in Section 409A of the Code, the general rule set forth in Section 6(a) will apply, unless Employee incurs a Separation from Service before December 31, 2024, in which case Employee shall receive a single lump sum payment of Employee's vested interest in his Discretionary Credit Account within 30 days following Employee's Separation from Service, unless Employee is a Specified Employee on the date of his Separation from Service. If Employee is a Specified Employee on the date of his Separation from Service, Employee's vested interest in his Discretionary Credit Account shall be paid within 30 days following the first day of the seventh month following Employee's Separation from Service.

(c) **Death.** If Employee dies while employed by the Company, or after the commencement of installment payments as described in Section 6(a) but before all such payments have been made in full, the Beneficiary designated by Employee pursuant to the Deferred Compensation Plan shall receive a single lump sum payment of Employee's vested interest in his Discretionary Credit Account within sixty days of Employee's death.

(d) **Termination without Cause.** If Employee's employment is terminated by the Company without cause and if, as a result of such termination, Employee incurs a Separation from Service before December 31, 2024, Employee shall receive a single lump sum payment of Employee's vested interest in his Discretionary Credit Account within 30 days following Employee's Separation from Service, unless Employee is a Specified Employee on the date of his Separation from Service. If Employee is a Specified Employee on the date of his Separation from Service, Employee's vested interest in his Discretionary Credit Account shall be paid within 30 days following the first day of the seventh month following Employee's Separation from Service.

7. **Employee's Plan Status.** Regardless of whether Employee makes an Annual Deferral pursuant to the terms of the Deferred Compensation Plan for the relevant Plan Year, Employee shall be deemed to be a Participant in the Deferred Compensation Plan and to have elected to participate in the Deferred Compensation Plan for the limited purpose of receiving the Discretionary Credits described in this Agreement. This Agreement shall be deemed to be Employee's Election Form for purposes of Section 2.2 and Section 3.3 of the Deferred Compensation Plan.

8. **Relationship to Other Benefits.** The Discretionary Credits allocated to Employee pursuant to this Agreement shall not be taken into account as compensation or for purposes of determining any benefits due to Employee pursuant to the terms of any pension, retirement, savings, profit sharing, incentive, group insurance or other tax qualified or nonqualified benefit plan sponsored by APS, Pinnacle West Capital Corporation or any affiliate of either. In addition, the amounts payable to Employee attributable to the Discretionary Credit Account established for Employee pursuant to the Deferred Compensation Plan shall be disregarded for purposes of the benefit plans referred to in the preceding sentence.

9. **Plan Document.** As provided above, this Agreement is entered into pursuant to the provisions of Section 3.9 of the Deferred Compensation Plan. Accordingly, except as

otherwise set forth in this Agreement, the provisions of the Deferred Compensation Plan shall apply in determining the rights of Employee as well as the administration of Employee's Discretionary Credit Account. In cases of conflict, this Agreement controls over any conflicting provisions of the Deferred Compensation Plan, except as may be required by Section 409A of the Internal Revenue Code or the provisions of any other applicable law or regulation.

10. **Amendments.** This Agreement may not be modified, altered or changed except by a written agreement signed by APS and Employee.

11. **Confidentiality.** Employee shall hold the existence and terms of this Agreement in confidence. Employee shall not publicly or privately discuss or disclose the nature or content of this Agreement. However, Employee may disclose the terms of this Agreement if required by federal or state law, and Employee may disclose the terms of this Agreement to Employee's accountant, attorney, consultant and spouse. In addition, APS and Employee may disclose this Agreement as necessary to enforce its provisions.

12. **Reporting to Federal and State Agencies.** Nothing in this Agreement shall be construed to prohibit Employee from reporting or disclosing any suspected instance of illegal activity of any nature, any nuclear safety concerns, any workplace safety concerns, or any public safety concerns to the Nuclear Regulatory Commission ("NRC"), the United States Department of Labor ("DOL"), or any other federal, state, or local government agency or court. This Agreement shall not be construed to prohibit Employee from providing information to the NRC, DOL, Equal Employment Opportunity Commission, United States Securities and Exchange Commission, Occupational Safety and Health Administration, or Arizona Division of Occupational Safety and Health, or testifying in any civil or criminal proceedings, even if such information or testimony being provided relates to the claims or matters covered by this Agreement. This Agreement shall not be construed as a waiver or withdrawal of any safety concerns which Employee has or may have reported to the NRC or DOL, or withdrawal of any participation by Employee in any NRC proceedings. In this regard, the parties to this Agreement understand that this Agreement shall be interpreted in a manner consistent with 10 CFR § 50.7(f). Notwithstanding anything to the contrary in this paragraph, Employee hereby waives and releases any right to receive any relief as a result of the Employee's participation in any investigation or proceeding of the NRC, DOL, or any federal, state, or local government agency or court.

13. **Entire Agreement.** APS and Employee acknowledge and agree that this Agreement and the Deferred Compensation Plan constitute the entire agreement between APS and Employee with respect to the subject matter hereof.

14. **Severability.** If any provision of this Agreement is held to be invalid, the remaining provisions shall remain in full force and effect.

IN WITNESS WHEREOF, APS and Employee have executed this Agreement on the dates set forth below.

ARIZONA PUBLIC SERVICE COMPANY

By: /s/ Donald E. Brandt
Donald E. Brandt
Chairman and Chief Executive Officer

Date: June 19, 2019

EMPLOYEE

/s/ Jacob Tetlow
Jacob Tetlow

Date: June 21, 2019

**FIRST AMENDMENT
TO THE
DISCRETIONARY CREDIT AWARD AGREEMENT**

Arizona Public Service Company (“APS”) previously entered into the Discretionary Credit Award Agreement dated June 21, 2019 (the “Agreement”) with Jacob Tetlow (“Employee”). By execution of this instrument, APS desires to amend the Agreement as set forth below.

1. This First Amendment shall be effective as of the date on which it is executed.
2. This First Amendment amends the provisions of the Agreement noted below. This First Amendment supersedes the other provisions of the Agreement to the extent those provisions are inconsistent with the provisions and intent of this First Amendment.
3. Section 3 (Discretionary Credits) of the Agreement is hereby amended and restated in its entirety to read as follows:

Discretionary Credits. Five Discretionary Credits in the aggregate amount of \$450,000 will be allocated to a Discretionary Credit Account (the “Discretionary Credit Account”) established for the benefit of Employee pursuant to Section 3.9 of the Deferred Compensation Plan. The Discretionary Credit Account shall be credited with: (i) \$100,000 on July 1, 2019; (ii) \$50,000 on January 1, 2020 and (iii) \$100,000 on each of January 1, 2021 through January 1, 2023 provided that the Employee remains employed with APS on each such crediting date and demonstrates sustained competent performance of his assigned job responsibilities.

4. Section 5 (Vesting) of the Agreement is hereby amended and restated in its entirety to read as follows:

Vesting. The Discretionary Credit Account vests on December 31, 2024. If Employee Separates from Service prior to December 31, 2024, the amounts allocated to the Discretionary Credit Account will be forfeited; provided, however, that if Employee is promoted to Executive Vice President, Employee’s employment with APS is involuntarily terminated by APS without Cause, Employee dies or Employee becomes Disabled prior to December 31, 2024, all amounts previously credited to the Discretionary Credit Account will be fully vested as of the date of the promotion, termination by APS without Cause, death or Disability as applicable and any credits not yet allocated to the Employee at the date of the promotion, termination by APS without Cause, death or Disability will be forfeited. For purposes of this document, “Disability” shall have the meaning ascribed to it in the Pinnacle West Capital Corporation Long-Term Disability Plan. For purposes of this document, “Cause” means any act or omission that could result in disciplinary action pursuant to applicable laws or APS policies and procedures, as determined in the sole discretion of APS. The determination of whether “Cause” exists shall be made by APS, in its sole and absolute discretion, in accordance with its personnel policies and procedures.

5. Except as otherwise amended by this First Amendment, the Agreement shall continue in full force and effect.
-

IN WITNESS WHEREOF, APS and Employee have executed this First Amendment to the Agreement on the dates set forth below.

ARIZONA PUBLIC SERVICE COMPANY

By: /s/ Jeffrey B. Guldner
Jeffrey B. Guldner
Chairman and Chief Executive Officer

Date: 02/23/2021

EMPLOYEE

/s/ Jacob Tetlow
Jacob Tetlow

Date: 02/17/2021

Summary of 2023 Incentive Plans

On December 13, 2022, the Human Resources Committee (the “Committee”) of the Pinnacle West Capital Corporation (“Pinnacle West”) Board of Directors (the “Board”) approved the portion of the Arizona Public Service Company (“APS”) 2023 Annual Incentive Award Plan (the “APS Plan”) that provides an incentive award opportunity for Jeffrey B. Guldner, Chairman of the Board, President and Chief Executive Officer of Pinnacle West and Chairman of the Board of Directors and Chief Executive Officer of APS. On December 14, 2022, the Board, acting on the recommendation of the Committee, approved the portion of the APS Plan that includes an incentive award opportunity for Andrew D. Cooper, Senior Vice President and Chief Financial Officer of Pinnacle West and APS, Theodore N. Geisler, President of APS and Robert E. Smith, Executive Vice President, General Counsel and Chief Development Officer of Pinnacle West and APS.

No incentive payments will be awarded under the APS Plan unless Pinnacle West, with respect to Mr. Guldner, or APS, with respect to Messrs. Cooper, Geisler and Smith, each achieves a specified threshold earnings level. The award opportunities for Mr. Guldner under the APS Plan are based on the achievement of specified 2023 Pinnacle West earnings levels and specified business unit performance goals. Mr. Guldner has a target award opportunity of up to 115% of his base salary. Mr. Guldner may earn less or more than the target amount, up to a maximum award opportunity of 230% of base salary, depending on the achievement of the earnings and business unit performance goals separately or in combination, and before adjustment for individual performance. The business unit performance indicators for Mr. Guldner are based on the average results of all five business units (Transmission and Distribution, Customer Experience and Communications, Generation (Non-Nuclear), Corporate Resources and Palo Verde) and consist of employee safety, customer experience, customer affordability and reliability.

The award opportunities for Messrs. Cooper, Geisler and Smith under the APS Plan are based on the achievement of specified 2023 APS earnings levels and specified business unit performance goals. Mr. Cooper has a target award opportunity of up to 70% of his base salary, Mr. Geisler has a target award opportunity of up to 85% of his base salary and Mr. Smith has a target award opportunity of up to 75% of his base salary. Messrs. Cooper, Geisler and Smith may earn less or more than the target amount, up to a maximum award opportunity of 140% for Mr. Cooper, 170% for Mr. Geisler and 150% for Mr. Smith, depending on the achievement of the earnings and business unit performance goals separately or in combination, and before adjustment for individual performance. The business unit performance indicators that will be considered for Messrs. Cooper, Geisler and Smith vary based off the applicable business unit but in all cases are closely tied to the APS Promise and include metrics such as employee safety, customer experience, customer affordability and reliability.

The Committee may adjust targets or incentive results under the APS Plan to reflect unanticipated events or unusual or nonrecurring adjustments to Pinnacle West or APS earnings (as applicable) that arise in the APS Plan year, including without limitation, Arizona Corporation Commission rate-related impacts on earnings. Any awards for Messrs. Guldner, Cooper, Geisler and Smith are subject to potential forfeiture or recovery in accordance with Pinnacle West’s Clawback Policy.

SUBSIDIARIES LIST

Arizona Public Service Company

*All other subsidiaries of Pinnacle West Capital Corporation and all subsidiaries of Arizona Public Service Company have been omitted as they do not constitute significant subsidiaries within the meaning of Rule 1-02(w) of Regulation S-X.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-224366, 333-239238 and 333-253889 on Form S-3 and Registration Statement Nos. 333-143432, 333-182427, 333-157151 and 333-256759 on Form S-8 of our report dated February 27, 2023, relating to the financial statements of Pinnacle West Capital Corporation and the effectiveness of Pinnacle West Capital Corporation's internal control over financial reporting appearing in this Annual Report on Form 10-K for the year ended December 31, 2022.

/s/ Deloitte & Touche LLP

Tempe, Arizona
February 27, 2023

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-224366-01 and 333-253889-01 on Form S-3 and Registration Statement Nos. 333-46161 and 333-158774 on Form S-8 of our report dated February 27, 2023, relating to the financial statements of Arizona Public Service Company and the effectiveness of Arizona Public Service Company's internal control over financial reporting appearing in this Annual Report on Form 10-K for the year ended December 31, 2022.

/s/ Deloitte & Touche LLP

Tempe, Arizona
February 27, 2023

CERTIFICATION

I, Jeffrey B. Guldner, certify that:

1. I have reviewed this Annual Report on Form 10-K of Pinnacle West Capital Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2023

/s/ Jeffrey B. Guldner

Jeffrey B. Guldner

Chairman of the Board, President and Chief Executive Officer

CERTIFICATION

I, Andrew Cooper, certify that:

1. I have reviewed this Annual Report on Form 10-K of Pinnacle West Capital Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2023

/s/ Andrew Cooper

Andrew Cooper

Senior Vice President and Chief Financial Officer

CERTIFICATION

I, Jeffrey B. Guldner, certify that:

1. I have reviewed this Annual Report on Form 10-K of Arizona Public Service Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2023

/s/ Jeffrey B. Guldner

Jeffrey B. Guldner

Chairman of the Board and Chief Executive Officer

CERTIFICATION

I, Andrew Cooper, certify that:

1. I have reviewed this Annual Report on Form 10-K of Arizona Public Service Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2023

/s/ Andrew Cooper

Andrew Cooper

Senior Vice President and Chief Financial Officer

**CERTIFICATION
OF
CHIEF EXECUTIVE OFFICER
AND
CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

I, Jeffrey B. Guldner, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Annual Report on Form 10-K of Pinnacle West Capital Corporation for the year ended December 31, 2022 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Annual Report on Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West Capital Corporation.

Date: February 27, 2023

/s/ Jeffrey B. Guldner

Jeffrey B. Guldner

Chairman of the Board, President and Chief Executive Officer

I, Andrew Cooper, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Annual Report on Form 10-K of Pinnacle West Capital Corporation for the quarter ended December 31, 2022 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Annual Report on Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West Capital Corporation.

Date: February 27, 2023

/s/ Andrew Cooper

Andrew Cooper

Senior Vice President and Chief Financial Officer

**CERTIFICATION
OF
CHIEF EXECUTIVE OFFICER
AND
CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

I, Jeffrey B. Guldner, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Annual Report on Form 10-K of Arizona Public Service Company for the year ended December 31, 2022 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Annual Report on Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Arizona Public Service Company.

Date: February 27, 2023

/s/ Jeffrey B. Guldner

Jeffrey B. Guldner

Chairman of the Board and Chief Executive Officer

I, Andrew Cooper, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Annual Report on Form 10-K of Arizona Public Service Company for the year ended December 31, 2022 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Annual Report on Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Arizona Public Service Company.

Date: February 27, 2023

/s/ Andrew Cooper

Andrew Cooper

Senior Vice President and Chief Financial Officer