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, 2019

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	☐	Smaller reporting company	☐
Emerging growth company	☐						

ARIZONA PUBLIC SERVICE COMPANY

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

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

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

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

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

PINNACLE WEST CAPITAL CORPORATION	$	10,536,165,750	as of June 30, 2019
ARIZONA PUBLIC SERVICE COMPANY	$	0	as of June 30, 2019

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 14, 2020:	112,439,441
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of February 14, 2020:	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 20, 2020 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
ASU	Accounting Standards Update
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
DC	Direct Current
distributed energy systems	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
MMBtu	One million British Thermal Units
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
OSM	Office of Surface Mining Reclamation and Enforcement
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)
PSA	Power supply adjustor approved by the ACC to provide for recovery or refund of variations in actual fuel and purchased power costs compared with the Base Fuel Rate
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
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" 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:

- 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, the general economy, customer and sales growth (or decline), the effects of energy conservation measures and distributed generation, and technological advancements;
- 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, including those relating to environmental requirements, regulatory 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, including returns on and of debt and equity capital investment;
- our ability to meet renewable energy and energy efficiency mandates and recover related costs;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- current and future economic conditions in Arizona, including in real estate markets;
- the direct or indirect effect on our facilities or business from cybersecurity threats or intrusions, data security breaches, terrorist attack, physical attack, severe storms, droughts, 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;
- the cost of debt and equity capital and the ability to access capital markets when required;
- environmental, economic and other concerns surrounding coal-fired generation, including regulation of greenhouse gas 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 land owners to meet contractual or other obligations or continue or discontinue power plant operations consistent with our corporate interests; 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.

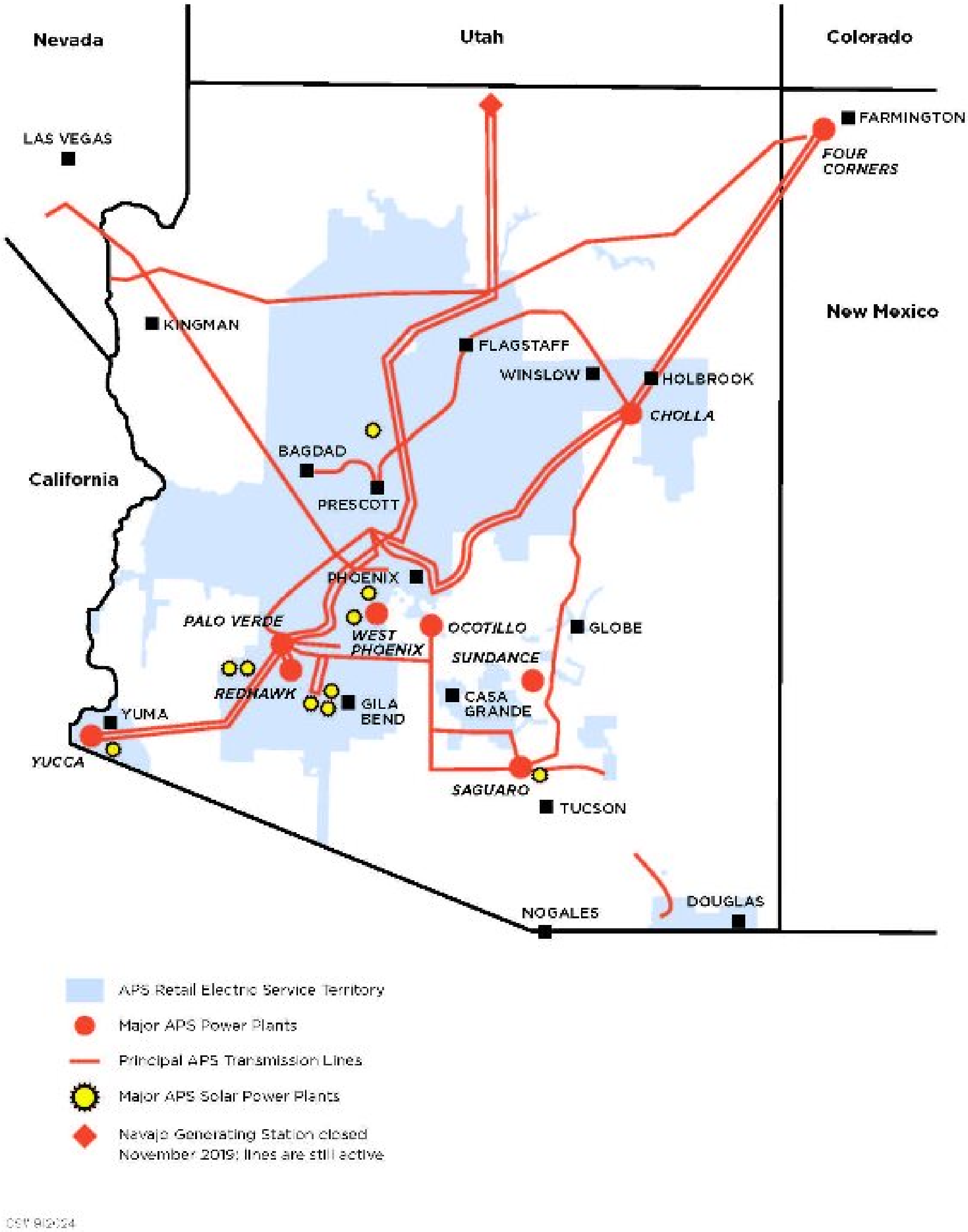
Pinnacle West's other subsidiaries are El Dorado, BCE and 4CA. Additional information related to these subsidiaries is provided later in this report.

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

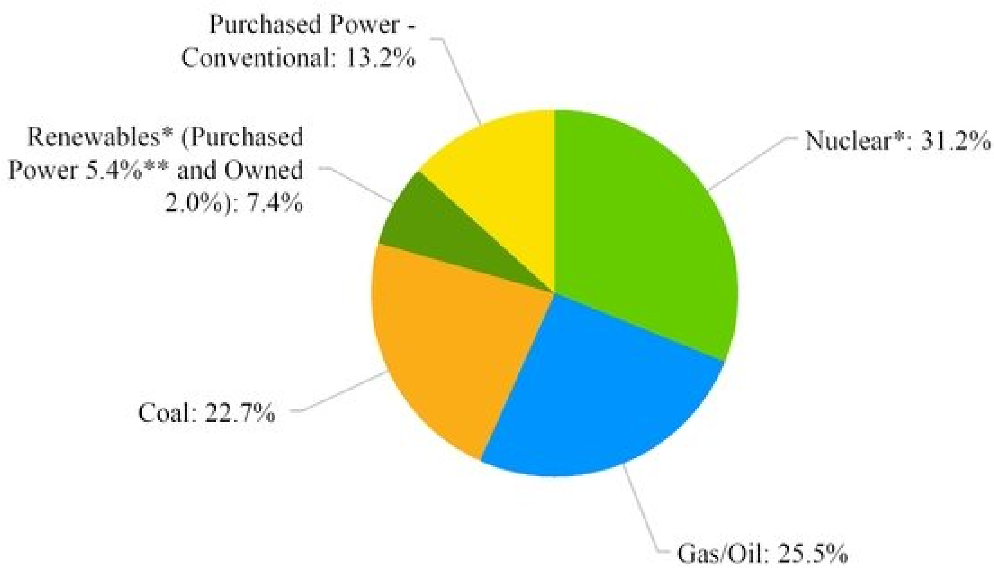
APS currently provides electric service to approximately 1.3 million customers. We own or lease 6,316 MW of regulated generation capacity and we hold a mix of both long-term and short-term purchased power agreements for additional capacity, including a variety of agreements for the purchase of renewable energy. During 2019, no single purchaser or user of energy accounted for more than 1.7% 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 2019 were as follows:



* When including APS’s historical energy efficiency and distributed generation energy contributions, the share of our customers’ energy supply being derived from clean resources is 51%.
** Purchased Power includes renewables from long-term power purchase agreements with grid-scale renewables providers and distributed generation.

__Clean Energy Focus Initiatives__

APS has undertaken a number of initiatives to address emission concerns, 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, APS recently announced its Clean Energy Commitment, a three-pronged approach aimed at ultimately eliminating carbon-emitting resources from its electric generation resource portfolio.

APS’s Clean Energy Commitment consists of three parts. First, APS announced an aspirational goal to generate electricity with zero-carbon emissions by 2050. Second, APS announced a nearer-term 2030 target of 65% clean energy, with 45% of APS's generation coming from renewable energy. Third, APS committed to eliminate coal-fired generation from its portfolio of electricity generating resources 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; cease buying coal-generation; managing demand with a modern interactive grid; promoting customer technology and energy efficiency; and optimizing regional resources. (See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operation" for additional information about our 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. Moreover, 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.

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 the full scope of the Company's GHG emissions arising from all APS operations. In addition to GHG emissions from generation and transmission and distribution operations, this data includes all other GHG emissions arising from ancillary Company operations, such as vehicle use, employee travel, portable generators and facility energy usage. This data is then communicated to the public in Pinnacle West's annual Corporate Responsibility Report, which is available on our website (*www.pinnaclewest.com*). The report provides information related to the Company and its approach to sustainability and its workplace and environmental performance. The information on Pinnacle West's website, including the Corporate Responsibility Report, is not incorporated by reference into or otherwise a part of this report.

Generation Facilities

APS has ownership interests in or leases the coal, nuclear, gas, oil and solar generating 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 resulted in APS retaining the assets through 2023 under one lease and 2033 under the other two leases. 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 19 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 2025 and 30% through 2028; 100% of Palo Verde's requirements for conversion services through 2025, and 40% through 2030; 100% of Palo Verde's requirements for enrichment services through 2021, 90% for 2022, and 80% for 2023 through 2026; and 100% of Palo Verde's requirements for fuel fabrication through 2027.

Spent Nuclear Fuel and Waste Disposal — The Nuclear Waste Policy Act of 1982 ("NWPA") required the DOE 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 provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2016, which was extended to December 31, 2019.

APS has submitted and received payment for five claims pursuant to the terms of the August 18, 2014 settlement agreement, for five separate time periods during July 1, 2011 through June 30, 2018. The DOE has paid $84.3 million for these claims (APS's share is $24.5 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. APS's next claim pursuant to the terms of the August 18, 2014 settlement agreement was submitted to the DOE on October 31, 2019 in the amount of $16 million (APS's share is $4.7 million). On February 11, 2020, the DOE approved a payment of $15.4 million (APS's share is $4.5 million).

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 NEPA. 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 20 for additional information about APS's nuclear decommissioning trusts.

Palo Verde Liability and Insurance Matters — See “Palo Verde Generating Station — Nuclear Insurance” in Note 11 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. Gas for these plants is financially hedged up to five years in advance of purchasing and the gas is generally purchased one month prior to delivery. APS has long-term gas transportation agreements with three different companies, some of which are effective through 2027. 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 the metropolitan Phoenix area. 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. (See Note 4 for rate recovery as part of the ACC final written Opinion and Order issued reflecting its decision in APS’s general retail rate case (the "2017 Rate Case Decision")). 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 recently announced Clean Energy Commitment, APS has committed to eliminate coal-fired generation from 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. The sale transaction closed on July 3, 2018. NTEC purchased the 7% interest at 4CA’s book value, approximately $70 million, and is paying 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note. 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.

The 2016 Coal Supply Agreement contained alternate pricing terms for the 7% interest in the event NTEC did not purchase the interest. Until the time that NTEC purchased the 7% interest, the alternate pricing provisions were applicable to 4CA as the holder of the 7% interest. These terms included a formula under which NTEC must make certain payments to 4CA for reimbursement of operations and maintenance costs and a specified rate of return, offset by revenue generated by 4CA's power sales. The amount under this formula for calendar year 2018 (up to the date that NTEC purchased the 7% interest) was approximately $10 million, which was due to 4CA on December 31, 2019. Such payment was satisfied in January 2020 by NTEC directing to 4CA a prepayment from APS of future coal payment obligations.

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 extending the life of the plant and the adjacent mine.

On April 20, 2016, several environmental groups filed a lawsuit against OSM and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both the Endangered Species Act ("ESA") and the National Environmental Policy Act ("NEPA") in providing the federal approvals necessary to extend operations at Four Corners and the adjacent Navajo Mine past July 6, 2016. APS filed a motion to intervene in the proceedings, which was granted on August 3, 2016.

On September 15, 2016, NTEC, the company that owns the adjacent mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. On September 11, 2017, the Arizona District Court issued an order granting NTEC's motion, dismissing the litigation with prejudice, and terminating the proceedings. On November 9, 2017, the environmental group plaintiffs appealed the district court order dismissing their lawsuit. On July 29, 2019, the Ninth Circuit Court of Appeals affirmed the September 2017 dismissal of the lawsuit, after which the environmental group plaintiffs petitioned the Ninth Circuit for rehearing on September 12, 2019. The Ninth Circuit denied this petition for rehearing on December 11, 2019.

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 operates that unit for PacifiCorp. On September 11, 2014, APS announced that it would close its 260 MW Unit 2 at Cholla and cease burning coal at Units 1 and 3 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, which was later addressed in the March 27, 2017 settlement agreement regarding APS's general retail case (the "2017 Settlement Agreement"). (See Note 4 for details related to the resulting regulatory asset and allowed recovery set forth in the 2017 Settlement Agreement.) APS believes that the environmental benefits of this proposal are greater in the long-term than the benefits that would have resulted from adding the emissions control equipment. APS closed Unit 2 on October 1, 2015. Following the closure of Unit 2, APS has a total entitlement from Cholla of 387 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 plans to retire Cholla Unit 4 by the end of 2020.

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 2020, with the ability to extend the contract annually through 2024.

Navajo Plant — The Navajo Plant is a 3-unit coal-fired power plant located in northern Arizona. Salt River Project operates the plant and APS owns a 14% interest in Units 1, 2 and 3. APS had a total entitlement from the Navajo Plant of 315 MW. The Navajo Plant's coal requirements were purchased from a supplier with long-term leases from the Navajo Nation and the Hopi Tribe. The Navajo Plant was under contract with its coal supplier through 2019, with extension rights through 2026. 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 that allows 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 4 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 11 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 170 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 40 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 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 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 - $15 million in capital costs each year to install utility-owned distributed generation 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 5 MW of distributed generation systems under the APS Solar Communities program.

Energy Storage

APS deploys a number of advanced technologies on its system, including energy storage. Storage can provide capacity, improve power quality, be utilized for system regulation, integrate renewable generation, and can be used to defer certain traditional infrastructure investments. Energy storage can also aid in integrating higher levels of renewables 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 benefit customers, to increase renewable utilization, and to further our understanding of how storage works with other advanced technologies and the grid. We are preparing for additional energy storage in the future.

In early 2018, APS entered into a 15-year power purchase agreement for a 65 MW solar facility that charges a 50 MW solar-fueled battery. Service under this agreement is scheduled to begin in 2021. In 2018, APS issued a request for proposal for approximately 106 MW of energy storage to be located at up to five of its AZ Sun sites. Based upon our evaluation of the Request for Proposals ("RFP") responses, APS decided to expand the initial phase of battery deployment to 141 MW by adding a sixth AZ Sun site. In February 2019, we contracted for the 141 MW and originally anticipated such facilities could be in service by mid-2020. In April 2019, a battery module in APS's McMicken battery energy storage facility experienced an equipment failure, which prompted an internal investigation to determine the cause. The results of the investigation will inform the timing of our utilization and implementation of batteries on our system. Due to the April 2019 event, APS is working with the counterparty for the AZ Sun sites to determine appropriate timing and path forward for such facilities. Additionally, in February 2019, APS signed two 20-year power purchase agreements for energy storage totaling 150 MW. Service under these power purchase agreements is also dependent on the results of the McMicken battery incident investigation and requires approval from the ACC to allow for recovery of these agreements through the PSA (See Note 4 for details related to the PSA).

We currently plan to install at least 850 MW of energy storage by 2025, including the 150 MW of energy storage projects under power purchase agreements described above. The additional 700 MW of APS-owned energy storage is expected to be made up of the retrofits associated with our AZ Sun sites as described above, along with current and future RFPs for energy storage and solar plus energy storage projects. Given the April 2019 event, we continue to evaluate the appropriate timing and path forward to support the overall capacity goals for our system and associated energy storage requirements. Currently, APS is pursuing an RFP for battery-ready solar resources up to 150 MW with results expected in the first half of 2020.

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 17.) APS continually assesses its need for additional capacity resources to assure system reliability. In addition, APS has also entered into several power purchase agreements for energy storage. (See "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Energy Storage" above for details of our energy storage power purchase agreements.)

Purchased Power Capacity — APS's purchased power capacity under long-term contracts as of December 31, 2019 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, 2020	60
Exchange Agreement (b)	May 15 to September 15 annually through February 2021	480
Demand Response Agreement (c)	Summer seasons through 2024	25
Tolling Agreement	Summer seasons from Summer 2020 through Summer 2025	565
Tolling Agreement	June 1 through September 30, 2020-2026	570
Renewable Energy (d)	Various	626
Tolling Agreement	May 1 through October 31, 2021-2027	463

(a) Up to 60 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) This is a seasonal capacity exchange agreement under which APS receives electricity during the summer peak season (from May 15 to September 15) and APS returns a like amount of electricity during the winter season (from October 15 to February 15).
(c) The capacity under this agreement may be increased in 10 MW increments in years 2017 through 2024, up to a maximum of 50 MW.
(d) 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 2019 peak one-hour demand on its electric system was recorded on August 5, 2019 at 7,115 MW, compared to the 2018 peak of 7,320 MW recorded on July 24, 2018. The reduction was largely driven by milder peak day weather conditions in 2019. APS's reserve margin at the time of the 2019 peak demand, calculated using system load serving capacity, was 16%. For 2020, 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 fifteen-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. In March of 2018, the ACC reviewed the 2017 IRPs of its jurisdictional utilities and voted to not acknowledge any of the plans. APS does not believe that this lack of acknowledgment will have a material impact on our financial position, results of operations or cash flows. 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 IRP's from April 1, 2020 to June 26, 2020.

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

In 2015, APS and the CAISO, the operator for the majority of California's transmission grid, signed an agreement for APS to begin participation in the Energy Imbalance Market ("EIM"). APS's participation in the EIM began on October 1, 2016. The EIM allows for rebalancing supply and demand in 15-minute blocks, with dispatching every five minutes before the energy is needed, instead of the traditional one hour blocks. APS continues to expect that its participation in EIM will lower its fuel costs, improve visibility and situational awareness for system operations in the Western Interconnection power grid, and improve integration of APS's renewable resources.

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 10% of retail electric sales in 2020 and increases annually until it reaches 15% in 2025. In APS's 2009 general retail rate case settlement agreement (the "2009 Settlement Agreement"), APS committed to use its best efforts to have 1,700 GWh of new renewable resources in service by year-end 2015 in addition to any existing resources or commitments as of the end of 2008. APS met its settlement commitment in 2015.

A component of the RES is focused on stimulating development of distributed energy systems. Accordingly, under the RES, an increasing percentage of that requirement must be supplied from distributed energy resources. This distributed energy requirement is 30% of the overall RES requirement of 10% in 2020. On July 1, 2019, APS filed its 2020 RES Implementation Plan. The following table summarizes the RES requirement standard (not including the additional commitment required by the 2009 Settlement Agreement) and its timing:

	2020	2025
RES (inclusive of distributed energy) as a % of retail electric sales	10%	15%
Percent of RES to be supplied from distributed energy resources	30%	30%

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. See "Energy Modernization Plan" in Note 4 for information regarding an additional renewable energy standards proposal.

Renewable Energy Portfolio. To date, APS has a diverse portfolio of existing and planned renewable resources totaling 1,923 MW, including solar, wind, geothermal, biomass and biogas. Of this portfolio, 1,828 MW are currently in operation and 95 MW are under contract for development or are under construction. Renewable resources in operation include 240 MW of facilities owned by APS, 626 MW of long-term purchased power agreements, and an estimated 962 MW of customer-sited, third-party owned distributed energy resources.

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.

The following table summarizes APS's renewable energy sources currently in operation and under development as of December 31, 2019. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the projects to the electric grid.

	Location	Actual/ Target Commercial Operation Date	Term (Years)	Net Capacity In Operation (MW AC)	Net Capacity Planned/Under Development (MW AC)
APS Owned					
Solar:					
AZ Sun Program:					
Paloma	**Gila Bend, AZ**	**2011**		**17**	
Cotton Center	**Gila Bend, AZ**	**2011**		**17**	
Hyder Phase 1	**Hyder, AZ**	**2011**		**11**	
Hyder Phase 2	**Hyder, AZ**	**2012**		**5**	
Chino Valley	**Chino Valley, AZ**	**2012**		**19**	
Hyder II	**Hyder, AZ**	**2013**		**14**	
Foothills	**Yuma, AZ**	**2013**		**35**	
Gila Bend	**Gila Bend, AZ**	**2014**		**32**	
Luke AFB	**Glendale, AZ**	**2015**		**10**	
Desert Star	**Buckeye, AZ**	**2015**		**10**	
Subtotal AZ Sun Program				**170**	**—**
Multiple Facilities	**AZ**	**Various**		**4**	
Red Rock	**Red Rock, AZ**	**2016**		**40**	
Distributed Energy:					
APS Owned (a)	**AZ**	**Various**		**26**	
Total APS Owned				**240**	**—**
Purchased Power Agreements					
Solar:					
Solana	**Gila Bend, AZ**	**2013**	**30**	**250**	
RE Ajo	**Ajo, AZ**	**2011**	**25**	**5**	
Sun E AZ 1	**Prescott, AZ**	**2011**	**30**	**10**	
Saddle Mountain	**Tonopah, AZ**	**2012**	**30**	**15**	
Badger	**Tonopah, AZ**	**2013**	**30**	**15**	
Gillespie	**Maricopa County, AZ**	**2013**	**30**	**15**	
Solar + Energy Storage:					
First Solar	**Arlington, AZ**	**2021**	**15**		**50**
Wind:					
Aragonne Mesa	**Santa Rosa, NM**	**2006**	**20**	**90**	
High Lonesome	**Mountainair, NM**	**2009**	**30**	**100**	
Perrin Ranch Wind	**Williams, AZ**	**2012**	**25**	**99**	
Geothermal:					
Salton Sea	**Imperial County, CA**	**2006**	**23**	**10**	
Biomass:					
Snowflake	**Snowflake, AZ**	**2008**	**15**	**14**	
Biogas:					
NW Regional Landfill	**Surprise, AZ**	**2012**	**20**	**3**	
Total Purchased Power Agreements				**626**	**50**
Distributed Energy					
Solar (b)					
Third-party Owned	**AZ**	**Various**		**929**	**45**
Agreement 1	**Bagdad, AZ**	**2011**	**25**	**15**	
Agreement 2	**AZ**	**2011-2012**	**20-21**	**18**	
Total Distributed Energy				**962**	**45**
Total Renewable Portfolio				**1,828**	**95**

(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. Distributed generation is produced in DC and is converted to AC for reporting purposes.

Demand Side Management

In December 2009, Arizona regulators placed an increased focus on energy efficiency and other demand side management programs to encourage customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. The ACC initiated its Energy Efficiency rulemaking, with a proposed EES of 22% cumulative annual energy savings by 2020. This standard was adopted and became effective on January 1, 2011. This standard will likely impact Arizona's future energy resource needs. (See Note 4 for energy efficiency and other demand side management obligations).

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 4 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. The ACC opened a docket on November 4, 2013 to explore technological advances and innovative changes within the electric utility industry. A series of workshops in this docket were held in 2014 and another in February of 2015.

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. An ACC special open meeting workshop was held on December 3, 2018. No substantive action was taken, but interested parties were asked to submit written comments and respond to a list of questions from ACC Staff. 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. Interested parties filed comments to the ACC Staff report and a stakeholder meeting and workshop to discuss the retail electric competition rules and energy modernization plan proposals was held on July 30, 2019. ACC Commissioners submitted additional questions regarding this matter. 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. The ACC has scheduled a workshop for February 25-26, 2020 for further consideration and discussion of the retail electric competition rules. APS cannot predict whether these efforts will result in any changes and, if changes to the rules results, what impact these rules would have on APS.

Wholesale

FERC regulates rates for wholesale power sales and transmission services. (See Note 4 for information regarding APS's transmission rates.) During 2019, approximately 5.3% 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 fuels. 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 includes new APS transmission projects, along with other transmission costs for upgrades and replacements, including those for data center 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 distribution 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 pending climate-change related legislation in the 116th Congress will be considered in the Senate and then signed into law by President Trump. 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 and enacted and the specifics of the resulting program are established. These factors include 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 and no proposed agency rule regulating GHGs in Arizona at this time, 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 ("NSR") 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 those regulations had been stayed pending judicial review.

The ACE regulations are based upon measures that can be implemented to improve the heat rate of steam-electric power plants, specifically coal-fired EGUs. In contrast with the CPP, EPA's ACE regulations would not involve utility-level generation dispatch shifting away from coal-fired generation and toward renewable energy resources and natural gas-fired combined cycle power plants. EPA’s ACE regulations provide states and EPA regions (e.g., the Navajo Nation) with three years to develop plans establishing source-specific standards of performance based upon application of the ACE rule’s heat-rate improvement emission guidelines. While corresponding NSR reform regulations were proposed as part of EPA’s initial ACE proposal, the finalized ACE regulations did not include such reform measures. EPA announced that it will be taking final action on EPA's NSR reform proposal for EGUs in the near future.

We cannot at this time predict the outcome of EPA's regulatory actions repealing and replacing the CPP. Various state governments, industry organizations, and environmental and public-health public interest groups have filed lawsuits in the D.C. Circuit challenging the legality of EPA’s action, both, in repealing the CPP and issuing the ACE regulations. In addition, to the extent that the ACE regulations go into effect as finalized, it is not yet clear how the state of Arizona or EPA will implement these regulations as applied to APS’s coal-fired EGUs. In light of these uncertainties, APS is still evaluating the impact of the ACE regulations on its coal-fired generation fleet.

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-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. APS believed that EPA’s original 2012 final rule establishing controls constituting BART for Cholla, which would require installation of selective catalytic reduction ("SCR") controls, was unsupported and that EPA had no basis for disapproving Arizona’s State Implementation Plan ("SIP") and promulgating a Federal Implementation Plan ("FIP") that was inconsistent with the state’s considered BART determinations under the regional haze program. In September 2014, APS met with EPA to propose a compromise BART strategy, whereby APS would permanently close Cholla Unit 2 and cease burning coal at Units 1 and 3 by the mid-2020s. (See "Cholla" in Note 4 for information regarding future plans for Cholla and details related to the resulting regulatory asset.) APS made the proposal with the understanding that additional emission control equipment is unlikely to be required in the future because retiring and/or converting the units as contemplated in the proposal is more cost effective than, and will result in increased visibility improvement over, the BART requirements for oxides of nitrogen ("NOx") imposed through EPA's BART FIP. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect for Cholla on April 26, 2017.

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 4 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. (See "Four Corners - 4CA Matter" in Note 11 for a discussion of the NTEC purchase.) 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 Resource Conservation and Recovery Act ("RCRA") and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard 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, 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.

- 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.

- Based on an August 21, 2018 D.C. Circuit decision, which vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments, EPA recently proposed corresponding changes to federal CCR regulations. On November 4, 2019, EPA proposed that all unlined CCR surface impoundments, regardless of their impact (or lack thereof) upon surrounding groundwater, must cease operation and initiate closure by August 31, 2020 (with an optional three-month extension as needed for the completion of alternative disposal capacity).

- On November 4, 2019, EPA also proposed to change the manner by which facilities that have committed to cease burning coal in the near-term may qualify for alternative closure. Such qualification would allow CCR disposal units at these plants to continue operating, even though they would otherwise be subject to forced closure under the federal CCR regulations. EPA's proposal regarding alternative closure would require express EPA authorization for such facilities to continue operating their CCR disposal units under alternative closure.

We cannot at this time predict the outcome of these regulatory proceedings or when EPA will take final action. 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 $22 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $15 million. The Navajo Plant currently disposes of CCR in a dry landfill storage area. To comply with the CCR rule for the Navajo Plant, APS's share of incremental costs is 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 cease operating and initiate closure by October 31, 2020. APS initiated an assessment of corrective measures on January 14, 2019 and expects such assessment will continue through mid- to late-2020. As part of this assessment, APS continues to gather additional groundwater data and perform remedial evaluations as to the CCR disposal units at Cholla and Four Corners undergoing corrective action. In addition, APS will solicit input from the public, host public hearings, and select remedies 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 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 effluent limitation guidelines. On September 18, 2017, EPA finalized a regulation postponing the earliest date on which compliance with the effluent limitation guidelines for these waste-streams would be required from November 1, 2018 until November 1, 2020. In addition, on November 22, 2019, EPA published a proposed rule relaxing the “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) subject to best-professional judgment effluent limits. We cannot at this time predict the outcome of this rulemaking proceeding. Nonetheless, we expect that compliance with the resulting limitations will be required in connection with National Pollution Discharge Elimination System ("NPDES") discharge permit renewals at Four Corners (see "Four Corners National Pollutant Discharge Elimination System Permit," below, for more details). For the current NPDES permit issued to Four Corners, which is subject to an appeal by various environmental groups, the plant must comply with the existing “zero discharge” effluent limitation guidelines for bottom-ash transport wastewater by December 31, 2023. If those guidelines are changed, it is unclear when Four Corners would need to demonstrate compliance with any updated or revised standards. Cholla and the Navajo Plant do not require NPDES permitting.

Ozone National Ambient Air Quality Standards. On October 1, 2015, EPA finalized revisions to the primary ground-level ozone national ambient air quality standards (“NAAQS”) at a level of 70 parts per billion (“ppb”). 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 ("PRPs"). PRPs may be strictly, and often are 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") for OU3. Based upon discussions between the OU3 working group parties and EPA, along with the results of recent technical analyses prepared by the OU3 working group to supplement the RI/FS, APS anticipates finalizing the RI/FS in the spring or summer of 2020. We estimate that our costs related to this investigation and study will be approximately $2 million. We anticipate incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, 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 service provider lawsuit, filed a third-party complaint seeking contribution for its liability, if any, from APS and 28 other third-party defendants. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

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.

Federal Agency Environmental Lawsuit Related to Four Corners

See "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Generation Facilities - Coal-Fueled Generating Facilities - Four Corners" above for information regarding the lawsuit against OSM and other federal agencies in connection with their issuance of approvals necessary to extend the operation of Four Corners and the adjacent mine.

Four Corners National Pollutant Discharge Elimination System ("NPDES") 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 effluent limitation guidelines 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. This permit is now subject to a petition for review before the

EPA EAB, based upon a November 1, 2019 filing by several environmental groups. We cannot predict the outcome of this review and whether the review will have a material impact on our financial position, results of operations or cash flows.

Navajo Nation Environmental Issues

Four Corners and the Navajo Plant are located on the Navajo Reservation and are held under rights of way granted by the federal government, as well as leases from the Navajo Nation. See "Energy Sources and Resource Planning - Generation Facilities - Coal-Fueled Generating Facilities" above for additional information regarding these plants.

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act, and the Navajo Nation Pesticide Act (collectively, the "Navajo Acts"). The Navajo Acts purport to give the Navajo Nation Environmental Protection Agency authority to promulgate regulations covering air quality, drinking water, and pesticide activities, including those activities that occur at Four Corners and the Navajo Plant. On October 17, 1995, the Four Corners participants and the Navajo Plant participants each filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, challenging the applicability of the Navajo Acts as to Four Corners and the Navajo Plant. The Court has stayed these proceedings pursuant to a request by the parties, and the parties are seeking to negotiate a settlement.

In April 2000, the Navajo Nation Council approved operating permit regulations under the Navajo Nation Air Pollution Prevention and Control Act. APS believes the Navajo Nation exceeded its authority when it adopted the operating permit regulations. On July 12, 2000, the Four Corners participants and the Navajo Plant participants each filed a petition with the Navajo Supreme Court for review of these regulations. Those proceedings have been stayed, pending the settlement negotiations mentioned above. APS cannot currently predict the outcome of this matter.

On May 18, 2005, APS, SRP, as the operating agent for the Navajo Plant, and the Navajo Nation executed a Voluntary Compliance Agreement to resolve their disputes regarding the Navajo Nation Air Pollution Prevention and Control Act. As a result of this agreement, APS sought, and the courts granted, dismissal of the pending litigation in the Navajo Nation Supreme Court and the Navajo Nation District Court, to the extent the claims relate to the Clean Air Act. The agreement does not address or resolve any dispute relating to other Navajo Acts. APS cannot currently predict the outcome of this matter.

Water Supply

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. However, during the past 12 months the region has received snowfall and precipitation sufficient to recover the Navajo Reservoir to an optimum operating level, reducing the probability of shortage in future years. Although the watershed and reservoirs are in a good condition at this time, 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 of 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, but which is subject to further review by the trial court judge, accepts the proposed hydro-geologic testing protocols supported by APS and other industrial users of groundwater. A final decision by the trial court judge in this matter remains pending. 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. Other claims have been identified as ready for litigation in motions filed with the court. A trial is scheduled for June of 2020 regarding the contested claims of the Hopi tribe for federal reserve water rights. Similar claims of the

Navajo Nation are pending, but a schedule for discovery and resolution of the tribe's federal reserve water rights has not been established.

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.

BUSINESS OF OTHER SUBSIDIARIES

Bright Canyon Energy

On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE's focus is on new growth opportunities that leverage the Company's core expertise in the electric energy industry. BCE's first initiative is 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 transmission opportunities within the eleven states that comprise the Western Electricity Coordinating Council, 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. As of December 31, 2019, BCE had total assets of approximately $14 million.

On December 20, 2019, BCE acquired minority ownership positions in two wind farms developed by Tenaska Energy, Inc. and Tenaska Energy Holdings, LLC (collectively, "Tenaska"), the 242 MW Clear Creek wind farm in Missouri and the 250 MW Nobles 2 wind farm in Minnesota. The Clear Creek project is expected to achieve commercial operation in 2020 and deliver power under a long-term power purchase agreement. The Nobles 2 project is also expected to achieve commercial operation in 2020 and deliver power under a long-term power purchase agreement. BCE indirectly owns 9.9% of the Clear Creek project and 5.1% of the Nobles 2 project.

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's short-term goal is to prudently realize the value of its existing investments. As of December 31, 2019, El Dorado had total assets of approximately $9 million. 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.

4CA

4CA is a wholly-owned subsidiary of Pinnacle West. As of December 31, 2019, 4CA had total assets of approximately $55 million, primarily consisting of a note receivable from NTEC. See "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Generating Facilities - Coal-Fueled Generating Facilities - Four Corners" above for information regarding 4CA and the note receivable from NTEC.

OTHER INFORMATION

Subpoenas

Pinnacle West previously received grand jury subpoenas issued in connection with an investigation by the office of the United States Attorney for the District of Arizona. The subpoenas sought information principally pertaining to the 2014 statewide election races in Arizona for Secretary of State and for positions on the ACC. The subpoenas requested records involving certain Pinnacle West officers and employees, including the Company's former Chief Executive Officer, as well as communications between Pinnacle West personnel and a former ACC Commissioner. Pinnacle West understands the matter is closed.

Other Information

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, 2019
Pinnacle West	400 North Fifth Street Phoenix, AZ 85004	1985	97
APS	400 North Fifth Street P.O. Box 53999 Phoenix, AZ 85072-3999	1920	6,111
BCE	400 East Van Buren Phoenix, AZ 85004	2014	2
El Dorado	400 East Van Buren Phoenix, AZ 85004	1983	—
4CA	400 North Fifth Street Phoenix, AZ 85004	2016	—
Total			6,210

The APS number includes employees at jointly-owned generating facilities (approximately 2,457 employees) for which APS serves as the generating facility manager. Approximately 1,329 APS employees are union employees, represented by the International Brotherhood of Electrical Workers ("IBEW"). In January 2018, the Company concluded negotiations with the IBEW and approved a two-year extension of the contract set to expire on April 1, 2018. Under the extension, union members received wage increases for 2018 and 2019; there were no other changes. The current contract expires on April 1, 2020. In preparation for that expiration, the Company began negotiations with the IBEW in October 2019 and negotiations are ongoing.

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 602-250-4400).

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. Consequently, our financial condition and results of operations are dependent upon the satisfactory resolution of any APS rate proceedings 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.

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 fines and penalties depends upon compliance with federal, state and local statutes, regulations and ACC requirements, 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 dollars 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. However, changes in regulations or the imposition of new or revised laws or regulations could have an adverse impact on our results of operations. We are also unable to predict the impact on our business and operating results from pending or future regulatory activities of any of these agencies.

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 greenhouse gases, 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 and in a dry landfill storage area at the Navajo Plant. To the extent the rule requires the closure or modification of these CCR 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 national ambient air quality standards for nitrogen oxides, which set new, more stringent standards intended 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 CO_2, which is a major byproduct of the combustion of fossil fuel, and other GHG emissions.

Potential Financial Risks - Greenhouse Gas Regulation, the Clean Power Plan and Potential Litigation. In 2015, EPA finalized a rule to limit carbon dioxide emissions from existing power plants, the CPP. The implementation of this rule within the jurisdictions where APS operates could result in a shift in in-state generation from coal to natural gas and renewable generation. Such a substantial change in APS's generation portfolio could require additional capital investments and increased operating costs, and thus have a significant financial impact on the Company. EPA took action in October 2017 to repeal these regulations and in July 2019, EPA published final regulations, the ACE Rule, to replace the CPP with a new set of regulations. EPA's action in 2019 to repeal the CPP and replace it with the ACE regulations is currently subject to pending judicial review in the U.S. Court of Appeals for the District of Columbia.

Depending on the final outcome of a pending judicial review of ACE and repeal of the CPP, along with related regulatory activity to implement the ACE regulations, 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. 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 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 our power plants 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, 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. Such differences in the co-owners' willingness or ability to continue their participation could ultimately lead to disagreements among the parties as to how and whether to continue operation of such plants, which could lead to eventual shut down of units or facilities and uncertainty related to the resulting cost recovery of such assets. See Note 4 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. 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.

One of these options would be a continuation or expansion of APS's existing AG (Alternative Generation)-X program, which essentially allows up to 200 MW of cumulative load to be served via a buy-through arrangement with competitive suppliers of generation. The AG-X program was approved by the ACC as part of the 2017 Settlement Agreement.

In November 2018, the ACC voted to again re-examine retail competition. In addition, proposals to enable or support retail electric competition may be made from time to time through ballot initiatives, legislative action or other forums in Arizona. The ACC has scheduled a workshop for February 25-26, 2020 for further consideration and discussion of the retail electric competition rules. APS cannot predict whether these efforts will result in any changes and, if changes to the rules results, what impact these rules would have on APS.

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.

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. The ACC has enacted rules regarding energy efficiency that mandate a 22% cumulative annual energy savings requirement by 2020. This will likely increase participation by APS customers in energy efficiency and conservation programs and other demand-side management efforts, which in turn will impact the demand for electricity. The rules also include a requirement for the ACC to review and address financial disincentives, recovery of fixed costs and the recovery of net lost revenue that would result from lower sales due to increased energy efficiency requirements. To that end, the LFCR is designed to address these matters.

APS must also meet certain distributed energy requirements. A portion of APS's total renewable energy requirement must be met with an increasing percentage of distributed energy resources (generally, small scale renewable technologies located on customers' properties). The distributed energy requirement is 30% of the applicable RES requirement for 2012 and subsequent years. Customer participation in distributed 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 2.0% for the year ended December 31, 2019 compared with the prior year. For the three years 2017 through 2019, APS's retail customer growth averaged 1.8% per year. We currently project annual customer growth to be 1.5 - 2.5% for 2020 and for 2020 through 2022 based on our assessment of improving economic conditions in Arizona.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 0.6% for the year ended December 31, 2019 compared with the prior year. Improving economic conditions and customer growth were offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives. For the three years 2017 through 2019, annual retail electricity sales were about flat, adjusted to exclude the effects of weather variations. We currently project that annual retail electricity sales in kWh will increase in the range of 1.0 - 2.0% for 2020 and increase on average in the range of 1.0 - 2.0% during 2020 through 2022, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations and excluding the impacts of several new large data centers opening operations in Metro Phoenix. The impact of new large data centers could raise the range of expected sales annual growth rate over the 2020 to 2022 period, but demand from these customers remains uncertain at this point. Slower than expected growth of the Arizona economy or acceleration of the expected effects of customer conservation, energy efficiency or distributed renewable generation initiatives could further impact these estimates.

Actual customer and sales growth may differ from our projections as a result of numerous factors, such as economic conditions, customer growth, usage patterns and energy conservation, impacts of energy efficiency programs and growth in distributed renewable generation, and responses to retail price changes. Additionally, recovery of a substantial portion of our fixed costs of providing service is based upon the volumetric amount of our sales. If our customer growth rate does not continue to improve as projected, or if we experience acceleration of expected effects of customer conservation, energy efficiency or distributed renewable generation initiatives, we may be unable to reach our estimated sales projections, which could have a negative impact on our financial condition, results of operations and cash flows.

The operation of power generation facilities and transmission systems involves risks that could result in reduced output or unscheduled outages, 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 impacts existing in Arizona as those that led to the catastrophic wildfires in Northern 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 that were caused by or enhanced due to APS's negligence. The Arizona liability standard is different from that of California, which generally imposes liability for resulting damages without regard to fault. 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 or acquire generation resources to meet reliability requirements and other new or evolving standards or 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 generation portfolio. The current abundance of low, stably priced natural gas, together with environmental and other concerns surrounding coal-fired generation resources, 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. The development of any generation facility is 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's inability to adequately develop or acquire the necessary generation resources 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 and construction 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 and construct fossil fuel infrastructure projects in the future.

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 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 is prone to drought conditions, which could potentially affect the plants' water supplies. Climate change is also projected to exacerbate prolonged drought conditions. APS's inability to access sufficient supplies of water 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, in particular nation state actors, that seek to exploit potential vulnerabilities in the electric utility industry and wish to disrupt the U.S. bulk power, transmission and distribution 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 could be targets of unauthorized access and 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. 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 effect 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 could also require significant management attention and resources, and could have a material adverse impact on our financial condition, results of operations or cash flows.

We develop and maintain systems and processes aimed at detecting and preventing information and cybersecurity incidents which require significant investment, maintenance, and ongoing monitoring and updating as technologies and regulatory requirements change. These systems and processes may be insufficient to mitigate the possibility of information and 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 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, 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 will not be able to anticipate 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. As such attacks continue to increase in sophistication and frequency, we may be unable to prevent all such attacks from being successful in the future.

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. The market for cybersecurity insurance is relatively new and coverage available for cybersecurity events may 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 our 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. In addition, 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 occurring not only at Palo Verde, but at any other nuclear power reactor in the United States. Although we have 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.

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 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 fuels. 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 ("OTC") 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.

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 35% of employees eligible to retire by the end of 2024. Although we have undertaken efforts to recruit, train and develop new employees, we face increased competition for talent. We are subject to other employee workforce factors, such as the availability and retention of qualified personnel and the need to negotiate collective bargaining agreements with union employees. These or other employee workforce factors could negatively impact our business, financial condition or results of operations.

FINANCIAL RISKS

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 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, 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 the cost of maintaining these sources.

Changes in economic conditions, monetary policy, financial regulation 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 reduce 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.

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

While most of the Patient Protection and Affordable Care Act provisions have been implemented, changes to or repeal of that Act and 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 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;
- future sales by the Company of equity or equity-linked securities; and
- general domestic and international economic conditions.

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

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

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

- restrictions on our ability to engage in a wide range of "business combination" transactions with an "interested shareholder" (generally, any person who beneficially owns 10% or more of our outstanding voting power, or any of our affiliates or associates who beneficially owned 10% or more of our outstanding voting power at any time during the prior three years) or any affiliate or associate of an interested shareholder, unless specific conditions are met;
- anti-greenmail provisions of Arizona law and our bylaws that prohibit us from purchasing shares of our voting stock from beneficial owners of more than 5% of our outstanding shares unless specified conditions are satisfied;
- the ability of the Board of Directors to increase the size of and fill vacancies on the Board of Directors, whether resulting from such increase, or from death, resignation, disqualification or otherwise;

- the ability of our Board of Directors to issue additional shares of common stock and shares of preferred stock and to determine the price and, with respect to preferred stock, the other terms, including preferences and voting rights, of those shares without shareholder approval;
- restrictions that limit the rights of our shareholders to call a special meeting of shareholders; and
- restrictions regarding the rights of our shareholders to nominate directors or to submit proposals to be considered at shareholder meetings.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

Neither Pinnacle West nor APS has received written comments regarding its periodic or current reports from the SEC staff that were issued 180 days or more preceding the end of its 2019 fiscal year and that remain unresolved.

ITEM 2. PROPERTIES

Generation Facilities

APS

APS's portfolio of owned generating facilities as of December 31, 2019 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
Navajo (d)	—		Coal	Base Load	—
Ocotillo (e)	—		Gas	Peaking	—
Total Steam					1,357
Combined Cycle:					
Redhawk (f)	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/Fairview	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 (g)	1		Solar	As Available	17
Hyder I (g)	1		Solar	As Available	16
Paloma (g)	1		Solar	As Available	17
Chino Valley	1		Solar	As Available	19
Gila Bend (g)	1		Solar	As Available	32
Hyder II (g)	1		Solar	As Available	14
Foothills (g)	1		Solar	As Available	35
Luke AFB	1		Solar	As Available	10
Desert Star (g)	1		Solar	As Available	10
Red Rock	1		Solar	As Available	40
APS Owned Distributed Energy			Solar	As Available	26
Multiple facilities			Solar	As Available	4
Total Solar					240
Total Capacity					6,316

(a) 100% unless otherwise noted.
(b) Our 29.1% ownership in Palo Verde includes leased interests. 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 (17.49%), SCE (15.8%), El Paso (15.8%), Public Service Company of New Mexico (10.2%), Southern California Public Power Authority (5.91%), and Los Angeles Department of Water & Power (5.7%). The plant is operated by APS.
(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) Unit 3 was retired in October 2019 with Units 1 and 2 following in November 2019.
(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) Redhawk generation capacity increased by 104 MW following the Advanced Gas Path upgrade installed on both units.
(g) APS is under contract and currently plans to add battery storage at these AZ Sun sites. Due to the McMicken battery energy storage equipment failure, APS is working with the counterparty for the AZ Sun sites to determine appropriate timing and path forward for such facilities. (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.

4CA

4CA, a wholly-owned subsidiary of Pinnacle West, purchased El Paso's 7% interest in Units 4 and 5 of Four Corners on July 6, 2016 and subsequently sold the interest to NTEC on July 3, 2018. (See "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Generation Facilities - Coal-Fueled Generating Facilities - Four Corners" in Item 1 and "Four Corners - 4CA Matter" in Note 11 for additional information about 4CA's interest in Four Corners.)

Transmission and Distribution Facilities

Current Facilities. APS’s transmission facilities consist of approximately 6,192 pole miles of overhead lines and approximately 49 miles of underground lines, 5,969 miles of which are located in Arizona. APS’s distribution facilities consist of approximately 11,191 miles of overhead lines and approximately 22,092 miles of underground primary cable, all of which are located in Arizona. 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, 2019:

	Percent Owned (Weighted-Average)
Morgan — Pinnacle Peak System	64.6%
Palo Verde — Rudd 500kV System	50.0%
Round Valley System	50.0%
ANPP 500kV System	33.5%
Navajo Southern System	26.7%
Four Corners Switchyards	63.0%
Palo Verde — Yuma 500kV System	19.0%
Phoenix — Mead System	17.1%
Palo Verde — Morgan System	88.9%
Hassayampa — North Gila System	80.0%
Cholla 500kV Switchyard	85.7%
Saguaro 500kV Switchyard	60.0%
Kyrene - Knox System	50.0%

Expansion. Each year APS prepares and files with the ACC a ten-year transmission plan. In APS's 2020 plan, APS projects it will develop 29 miles of new transmission lines over the next ten years. One significant project, the Palo Verde to Morgan project recently completed all phases and provides a new 500kV path that spans from the Palo Verde hub around the western and northern edges of the Phoenix metropolitan area and terminates at a bulk substation in the northeast part of Phoenix. The Palo Verde to Morgan project includes Palo Verde-Delaney-Sun Valley-Morgan-Pinnacle Peak. The project consisted of four phases and the fourth phase, Morgan to Sun Valley 500kV, was energized in April of 2018. In total, the project consisted of over 100 miles of new 500kV lines, with many of those miles constructed with the capability to employ a 230kV line as a second circuit.

APS continues to work with regulators to identify transmission projects necessary to support renewable energy facilities. Two such projects, which have been completed and were included in previous APS transmission plans, are the Delaney to Palo Verde line and the North Gila to Hassayampa line, both of which support the transmission of renewable energy to Phoenix and California. The North Gila to Hassayampa line went into service in May 2015 and the Delaney to Palo Verde line went into service in May 2016.

NERC Critical Infrastructure Protection Reliability Standards. Since 2014, APS has been implementing a comprehensive project to ensure compliance with NERC's Critical Infrastructure Protection Reliability Standards ("CIP"). APS completed substantial implementation in the fourth quarter of 2019 for compliance with CIP standards that became effective January 1, 2020.

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 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 that allows for decommissioning activities to begin after the plant ceased operations in November 2019.

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 - Generating 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 4 for ACC and FERC-related matters.

See Note 11 for information regarding environmental matters and Superfund–related matters.

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 21, 2020, current positions and principal occupations for the past five years are as follows:

Name	Age	Position	Period
Jeffrey B. Guldner	54	Chairman of the Board, President and Chief Executive Office of Pinnacle West; Chairman of the Board and Chief Executive Officer of APS	2019-Present
		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
		Senior Vice President, Public Policy of APS	2014-2017
Robert S. Bement	64	Executive Vice President and Special Advisor to the Chief Executive Officer of APS	2020-Present
		Executive Vice President and Chief Nuclear Officer, PVGS, of APS	2016-2020
		Senior Vice President, Site Operations, PVGS, of APS	2011-2016
Elizabeth A. Blankenship	48	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
Donna M. Easterly	55	Senior Vice President, Human Resources of APS	2020-Present
		Vice President, Human Resources and Ethics of APS	2017-2020
		Vice President, Chief Procurement Officer of APS	2014-2017
Daniel T. Froetscher	58	President and Chief Operating Officer of APS	2020-Present
		Executive Vice President, Operations of APS	2018-2020
		Senior Vice President, Transmission, Distribution & Customers of APS	2014-2018
Theodore N. Geisler	41	Senior Vice President and Chief Financial Officer of Pinnacle West and APS	2020-Present
		Vice President and Chief Information Officer of APS	2018-2020
		General Manager, Transmission and Distribution Operations and Maintenance of APS	2017-2018
		Director, Investor Relations of Pinnacle West	2016-2017
		Director, Transmission Operations and Maintenance of APS	2013-2016
James R. Hatfield	62	Chief Administrative Officer and Treasurer of Pinnacle West and APS	2020-Present
		Executive Vice President of Pinnacle West and APS	2012-Present
		Chief Financial Officer of Pinnacle West and APS	2008-2020
Maria L. Lacal	59	Executive Vice President and Chief Nuclear Officer, PVGS, of APS	2020-Present
		Senior Vice President, Regulatory and Oversight, PVGS, of APS	2016-2020
		Vice President, Regulatory and Oversight, PVGS, of APS	2015-2016
		Vice President, Operations Support, PVGS, of APS	2011-2015
Barbara D. Lockwood	53	Senior Vice President, Public Policy of APS	2020-Present
		Vice President, Regulation of APS	2015-2020
		General Manager, Regulatory Policy and Compliance of APS	2014-2015
Lee R. Nickloy (a)	53	Vice President and Treasurer of Pinnacle West and APS	2010-Present
Robert E. Smith	50	Senior Vice President and General Counsel of Pinnacle West and APS	2018-Present
		Senior Vice President and General Counsel of Columbia Pipeline Group, Inc.	2014-2016

(a) Lee R. Nickloy is retiring from Pinnacle West and APS on March 2, 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 14, 2020, Pinnacle West's common stock was held of record by approximately 16,942 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, 2019, APS did not have any outstanding preferred stock.

ITEM 6. SELECTED FINANCIAL DATA

PINNACLE WEST CAPITAL CORPORATION – CONSOLIDATED

The selected data presented below as of and for the years ended December 31, 2019, 2018, 2017, 2016 and 2015 are derived from the Consolidated Financial Statements. The data should be read in connection with the Consolidated Financial Statements including the related notes included in Item 8 of this Form 10-K.

	2019	2018	2017	2016	2015
	(dollars in thousands, except per share amounts)				
OPERATING RESULTS					
Operating revenues	$ 3,471,209	$ 3,691,247	$ 3,565,296	$ 3,498,682	$ 3,495,443
Net income	557,813	530,540	507,949	461,527	456,190
Less: Net income attributable to noncontrolling interests	19,493	19,493	19,493	19,493	18,933
Net income attributable to common shareholders	$ 538,320	$ 511,047	$ 488,456	$ 442,034	$ 437,257
COMMON STOCK DATA					
Book value per share – year-end	$ 48.30	$ 46.59	$ 44.80	$ 43.14	$ 41.30
Earnings per weighted-average common share outstanding:					
Net income attributable to common shareholders – basic	$ 4.79	$ 4.56	$ 4.37	$ 3.97	$ 3.94
Net income attributable to common shareholders – diluted	$ 4.77	$ 4.54	$ 4.35	$ 3.95	$ 3.92
Dividends declared per share	$ 3.04	$ 2.87	$ 2.70	$ 2.56	$ 2.44
Weighted-average common shares outstanding – basic	112,442,818	112,129,017	111,838,922	111,408,729	111,025,944
Weighted-average common shares outstanding – diluted	112,758,059	112,549,722	112,366,675	112,046,043	111,552,130
BALANCE SHEET DATA					
Total assets	$ 18,479,247	$ 17,664,202	$ 17,019,082	$ 16,004,253	$ 15,028,258
Liabilities and equity:					
Current liabilities	$ 2,078,365	$ 1,648,964	$ 1,197,852	$ 1,292,946	$ 1,442,317
Long-term debt less current maturities	4,832,558	4,638,232	4,789,713	4,021,785	3,462,391
Deferred credits and other	6,015,136	6,028,301	5,895,787	5,753,610	5,404,093
Total liabilities	12,926,059	12,315,497	11,883,352	11,068,341	10,308,801
Total equity	5,553,188	5,348,705	5,135,730	4,935,912	4,719,457
Total liabilities and equity	$ 18,479,247	$ 17,664,202	$ 17,019,082	$ 16,004,253	$ 15,028,258

SELECTED FINANCIAL DATA

ARIZONA PUBLIC SERVICE COMPANY – CONSOLIDATED

	2019	2018	2017	2016	2015
			(dollars in thousands)		
OPERATING RESULTS					
Operating revenues	$ 3,471,209	$ 3,688,342	$ 3,557,652	$ 3,498,090	$ 3,494,900
Fuel and purchased power costs	1,042,237	1,094,020	992,744	1,082,625	1,101,298
Other operating expenses	1,741,988	1,764,554	1,640,369	1,556,980	1,556,670
Operating income	686,984	829,768	924,539	858,485	836,932
Other income	89,854	111,015	60,482	52,081	54,225
Interest expense — net of allowance for borrowed funds	201,646	206,211	192,051	183,090	176,109
Net income before income taxes	575,192	734,572	792,970	727,476	715,048
Income taxes	(9,572)	144,814	269,168	245,842	245,841
Net income	584,764	589,758	523,802	481,634	469,207
Less: Net income attributable to noncontrolling interests	19,493	19,493	19,493	19,493	18,933
Net income attributable to common shareholder	$ 565,271	$ 570,265	$ 504,309	$ 462,141	$ 450,274
BALANCE SHEET DATA					
Total assets	$ 18,370,723	$ 17,565,323	$ 16,893,751	$ 15,931,175	$ 14,982,182
Liabilities and equity:					
Total equity	$ 5,998,803	$ 5,786,797	$ 5,385,869	$ 5,037,970	$ 4,814,794
Long-term debt less current maturities	4,833,133	4,189,436	4,491,292	4,021,785	3,337,391
Total capitalization	10,831,936	9,976,233	9,877,161	9,059,755	8,152,185
Current liabilities	1,492,029	1,576,097	1,098,274	1,094,037	1,424,708
Deferred credits and other	6,046,758	6,012,993	5,918,316	5,777,383	5,405,289
Total liabilities and equity	$ 18,370,723	$ 17,565,323	$ 16,893,751	$ 15,931,175	$ 14,982,182

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 2019 results with 2018 results. A comparison of the 2018 results with 2017 results can be found in the Annual Report on Form 10-K for the fiscal year ended December 31, 2018. 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 $18 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.

Strategic Overview

Our strategy is to deliver shareholder value by creating a sustainable energy future for Arizona with a clean, affordable, reliable and customer-focused plan.

Clean Energy Commitment

We are committed to doing our part to make the future clean and carbon-free. Our vision for APS and Arizona presents an opportunity to engage with customers to achieve clean energy goals. Guided by science, our approach is intended to encourage market-based and innovative solutions to drive towards a low-carbon economy. We believe clean energy can power a robust economy.

APS's new clean energy goals consist of three parts:

- An aspirational 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 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 Aspirational 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 Electricity. APS has an energy mix that is already 50% clean with existing plans to add more renewables and energy storage before 2025. Those plans are intended to allow us to attain an energy mix that is 65% clean by 2030, with 45% of APS's portfolio coming from renewable energy. 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 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 buying coal-generation from 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 28% since 2005. In addition, APS has committed to end the use of coal at its remaining Cholla units by 2025.

Renewables. APS intends to strengthen its already diverse energy mix by increasing its investments in carbon-free resources. Its near-term actions include competitive solicitations to procure clean energy resources such as solar, wind, energy storage, demand response and DSM resources, including energy efficiency resources that enable renewable additions and lead to a cleaner grid.

Palo Verde. Palo Verde is the nation's largest producer of electricity and the largest source of carbon-free energy. The plant supplies nearly 70% of our clean energy and provides the foundation for the reliable and affordable service for APS customers. 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's 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

We believe it is APS's responsibility to deliver electric services to customers in the most cost-effective manner. Since January 2018, the average residential bill decreased by 7.8% or $11.68, due primarily to savings from lower operating costs in areas such as fuel and purchased power and federal tax reform that have been passed on to customers.

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 eliminating waste. Through the initiative and existing cost management practices, APS identified $20 million in possible cost savings for 2020.

Participation in the EIM continues to be an effective tool for creating savings for our customers from the real-time, voluntary market. Over the past three years, the EIM has delivered approximately $140 million in gross benefits to APS customers. 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.

Reliable

While our energy mix evolves, the obligation to deliver reliable service to our customers remains. Excluding voluntary outages and proactive fire mitigation efforts, APS finished 2019 with its best score for frequency of customer power outages.

Planned investments will support operating and maintaining the grid, updating technology, accommodating customer growth and enabling more renewable energy resources. Our advanced 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. (See "Liquidity and Capital Resources - Capital Expenditures" below for additional details on capital expenditures.)

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, 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.

Customer-Focused

Customers are at the core of what APS does every day and APS is committed to providing options that make it easier for its customers to do business with them. In 2019, APS launched its redesigned aps.com website and mobile app, giving customers upgraded access to their energy usage data and billing information. APS's Customer Care team is using speech analytics to enrich advisors' interactions with customers over the telephone, and customers can also communicate with APS through an online chat.

APS expanded financial help for its most vulnerable customers in 2019, allocating $2.75 million in crisis bill assistance and increasing the individual benefit for qualifying customers from $400 to $800 per year. The APS Solar Communities program has allowed more than 600 limited- and moderate-income customers to support clean energy and save money by hosting APS-owned solar systems on their residences in exchange for a monthly bill credit.

APS continues to develop and deploy innovative programs that connect customers with advanced technologies to help them manage their bills and encourage energy use during midday, when solar power is most abundant. Three energy storage programs incorporating smart thermostats, connected water heaters and batteries are helping customers shift energy use to times when they can take advantage of low-cost, abundant energy and reduce peak demand on APS's system.

In 2020, APS is convening an advisory panel of customers to gain a deeper understanding of the customer experience through their individual perspectives. A group of customer service advisors, in conjunction with local human services agencies, will provide in-person customer support in communities APS serves.

Emerging Technologies

Energy Storage

APS deploys a number of advanced technologies on its system, including energy storage. Storage can provide capacity, improve power quality, be utilized for system regulation, integrate renewable generation, and in certain circumstances, be used to defer certain traditional infrastructure investments. Energy storage can also aid in integrating higher levels of renewables 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 benefit customers, to increase renewable utilization, and to further our understanding of how storage works with other advanced technologies and the grid. We are preparing for additional energy storage in the future.

In early 2018, APS entered into a 15-year power purchase agreement for a 65 MW solar facility that charges a 50 MW solar-fueled battery. Service under this agreement is scheduled to begin in 2021. In 2018, APS issued a request for proposal for approximately 106 MW of energy storage to be located at up to five of its AZ Sun sites. Based upon our 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. In February 2019, we contracted for the 141 MW and originally anticipated such facilities could be in service by mid-2020. In April 2019, a battery module in APS's McMicken battery energy storage facility experienced an equipment failure, which prompted an internal investigation to determine the cause. The results of the investigation will inform the timing of our utilization and implementation of batteries on our system. Due to the April 2019 event, APS is working with the counterparty for the AZ Sun sites to determine appropriate timing and path forward for such facilities. Additionally, in February 2019, APS signed two 20-year power purchase agreements for energy storage totaling 150 MW. Service under these power purchase agreements is also dependent on the results of the McMicken battery incident investigation and requires approval from the ACC to allow for recovery of these agreements through the PSA.

We currently plan to install at least 850 MW of energy storage by 2025, including the 150 MW of energy storage projects under power purchase agreements described above. The additional 700 MW of APS-owned energy storage is expected to be made up of the retrofits associated with our AZ Sun sites as described above, along with current and future RFPs for energy storage and solar plus energy storage projects. Given the April 2019 event, we continue to evaluate the appropriate timing and path forward to support the overall capacity goals for our system and associated energy storage requirements. Currently, APS is pursuing an RFP for battery-ready solar resources up to 150 MW with results expected in the first half of 2020.

Electric Vehicles

APS plans to make electric vehicle charging more accessible for its customers and help Arizona businesses, schools and governments electrify their fleets. In 2019, APS implemented its Take Charge AZ Pilot Program. The program provides charging equipment, installation, and maintenance to business customers, government agencies, and multifamily housing communities. Rates are designed to encourage charging overnight and during daytime off-peak hours when solar energy is abundant.

Hydrogen Production

Palo Verde, in partnership with Idaho National Laboratory and two other utilities, has been chosen by the DOE's Office of Nuclear Energy to participate in a hydrogen production project with the goal to improve the long-term economic competitiveness of the nuclear power industry. The project, planned for 2020 through 2022, will look at how hydrogen from Palo Verde may be used as energy storage for use in reverse-operable electrolysis or peaking gas turbines during times of the day when photovoltaic solar energy sources are unavailable and energy reserves in the southwest United States are low. It could also be used to support a rapidly increasing hydrogen transportation fuel market.

Experience from the pilot project will offer insights into methods for flexible transitions between electricity and hydrogen generation missions in solar-dominated electricity markets, and demonstrate how hydrogen may be used as energy storage to provide electricity during operating periods when solar is not available.

Carbon Capture

Carbon capture technologies can isolate atmospheric CO_2 and either sequester it permanently in geologic formations or convert it for use in products. Currently, almost all existing fossil fuel generators do not control carbon emissions the way they control emissions of other air pollutants such as sulfur dioxide or oxides of nitrogen. At the same time, these generators are dispatchable: they can supply energy quickly as needed for reliability. Carbon capture technologies offer the potential to keep in operation existing generators that otherwise would need to be retired. There are a number of demonstration projects that show promise but are still being tested in real-world conditions. APS will continue to monitor this emerging technology.

Regulatory Overview

On October 31, 2019, APS filed an application with the ACC for an annual increase in retail base rates of $69 million. This amount includes recovery of the deferral and rate base effects of the Four Corners SCR project that is currently the subject of a separate proceeding (see "SCR Cost Recovery" in Note 4). 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 TEAM. The proposed total 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 are:

- a test year comprised of twelve 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:

	Capital Structure	Cost of Capital
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;
- 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 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 MW of medium and large commercial customers;

- recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project (see Note 4 discussion of the 2017 Settlement Agreement); and
- continued recovery of the remaining investment and other costs related to the retirement and closure of the Navajo Plant (see Note 4 for details related to the resulting regulatory asset).

APS requested that the increase become effective December 1, 2020. APS cannot predict the outcome of its request.

See Note 4 for information regarding additional regulatory matters.

Financial Strength and Flexibility

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

Other Subsidiaries

Bright Canyon Energy. On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE's focus is on new growth opportunities that leverage the Company's core expertise in the electric energy industry. BCE's first initiative is 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 transmission opportunities within the eleven states that comprise the Western Electricity Coordinating Council, 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 developed by Tenaska, the 242 MW Clear Creek wind farm in Missouri and the 250 MW Nobles 2 wind farm in Minnesota. The Clear Creek project is expected to achieve commercial operation in 2020 and deliver power under a long-term power purchase agreement. The Nobles 2 project is also expected to achieve commercial operation in 2020 and deliver power under a long-term power purchase agreement. BCE indirectly owns 9.9% of the Clear Creek project and 5.1% of the Nobles 2 project.

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 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.

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.

Operating Revenues. For the years 2017 through 2019, retail electric revenues comprised approximately 95% of our total operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, distributed energy additions, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery mechanisms. These revenue transactions are affected by the availability of excess generation or other energy resources and wholesale market conditions, including competition, demand and prices.

Actual and Projected Customer and Sales Growth. Retail customers in APS's service territory increased 2.0% for the year ended December 31, 2019 compared with the prior year. For the three years 2017 through 2019, APS's customer growth averaged 1.8% per year. We currently project annual customer growth to be 1.5 - 2.5% for 2020 and for 2020 through 2022 based on our assessment of steady economic growth in Arizona.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 0.6% for the year ended December 31, 2019 compared with the prior year. Steady economic growth and customer growth were offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives. For the three years 2017 through 2019, annual retail electricity sales were about flat, adjusted to exclude the effects of weather variations. We currently project that annual retail electricity sales in kWh will increase in the range of 1.0 - 2.0% for 2020 and increase on average in the range of 1.0 - 2.0% during 2020 through 2022, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations and excluding the impacts of several new large data centers opening operations in Metro Phoenix. The impact of new large data centers could raise the range of expected sales annual growth rate over the 2020 to 2022 period, but demand from these customers remains uncertain at this point. Slower than expected growth of the Arizona economy or acceleration of the expected effects of customer conservation, energy efficiency or distributed renewable generation initiatives could further impact these estimates.

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, impacts of energy efficiency programs and growth in distributed generation, and responses to retail price changes. Based on past experience, a reasonable range of variation in our kWh sales projections attributable to such economic factors under normal business conditions can result in increases or decreases in annual net income of up to approximately $15 million.

Weather. In forecasting the retail sales growth numbers provided above, we assume normal weather patterns based on historical data. Historically, extreme weather variations have resulted in annual variations in net income in excess of $25 million. However, our experience indicates that the more typical variations from normal weather can result in increases or decreases in annual net income of up to $15 million.

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 demand side management 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 and income tax impacts related to bonus depreciation.

***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 10.9% of the assessed value for 2019, 11.0% for 2018 and 11.2% for 2017. We expect property taxes to increase as we add new generating units and continue with improvements and expansions to our existing generating units and transmission and distribution facilities.

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 5 for details of the impacts on the Company as of December 31, 2019.) In APS's 2017 Rate Case Decision, the ACC approved the TEAM which is being used to pass through the income tax effects to retail customers of the Tax Act. (See Note 4 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 7). 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 – 2019 compared with 2018.

Our consolidated net income attributable to common shareholders for the year ended December 31, 2019 was $538 million, compared with $511 million for the prior year. The results reflect an increase of approximately $30 million for the regulated electricity segment primarily due to lower operations and maintenance costs and tax expense due to amortization of excess deferred taxes as a result of the Tax Act, partially offset by lower revenue due to the refunds provided to customers resulting from the Tax Act, and milder weather and lower pension and other postretirement non-service credits.

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

	Year Ended December 31,		
	2019	2018	Net change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 2,425	$ 2,590	$ (165)
Operations and maintenance	(939)	(1,025)	86
Depreciation and amortization	(591)	(581)	(10)
Taxes other than income taxes	(219)	(212)	(7)
Pension and other postretirement non-service credits - net	23	50	(27)
All other income and expenses, net	61	59	2
Interest charges, net of allowance for borrowed funds used during construction	(217)	(218)	1
Income taxes (Note 5)	16	(134)	150
Less income related to noncontrolling interests (Note 19)	(19)	(19)	—
Regulated electricity segment income	540	510	30
All other	(2)	1	(3)
Net Income Attributable to Common Shareholders	$ 538	$ 511	$ 27

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $165 million lower for the year ended December 31, 2019 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)		
Refunds due to lower Federal corporate income tax rate (Note 4)	$ (146)	$ —	$ (146)
Effects of weather	(32)	(8)	(24)
Lower renewable energy regulatory surcharges and higher purchased power, offset by operations and maintenance costs	(15)	2	(17)
Change in residential rate design (a)	13	—	13
Lost fixed cost recovery	8	—	8
Higher retail revenue due to higher customer growth, partially offset by the impacts of energy efficiency, distributed generation and changes in customer usage patterns	10	5	5
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	(60)	(61)	1
Miscellaneous items, net	5	10	(5)
Total	$ (217)	$ (52)	$ (165)

(a) As part of the 2017 Settlement Agreement, rate design changes were implemented that moved some revenue responsibility from summer to non-summer months. The change was made to better align revenue collections with costs of service.

Operations and maintenance. Operations and maintenance expenses decreased $86 million for the year ended December 31, 2019 compared with the prior-year period primarily because of:

- A decrease of $42 million related to public outreach costs at the parent company primarily associated with the ballot initiative in 2018;
- A decrease of $28 million in fossil generation costs primarily due to lower planned outages and operating costs, including $4 million of Navajo Plant costs which were offset in depreciation and amortization;
- A decrease of $19 million related to employee benefit costs;
- A decrease of $18 million related to costs for renewable energy and similar regulatory programs, which are offset in operating revenues and purchased power;
- An increase of $12 million for costs related to information technology;
- An increase of $12 million related to consulting costs; and

- A decrease of $3 million for other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $10 million higher for the year ended December 31, 2019 compared with the prior-year period primarily due to increased plant in service of $33 million, partially offset by the regulatory deferrals for the Four Corners SCR and Ocotillo modernization project of $19 million and the deferral of Navajo Plant costs of $4 million which is offset in operations and maintenance.

Taxes other than income taxes. Taxes other than income taxes were $7 million higher for the year ended December 31, 2019 compared with the prior-year period primarily due to higher property values.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $27 million lower for the year ended December 31, 2019 compared to the prior-year period primarily due to lower market returns in 2018.

Income taxes. Income taxes were $150 million lower for the year ended December 31, 2019 compared with the prior-year period primarily due to amortization of excess deferred taxes and lower pretax income in the current year period (see Note 5).

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, 2019, APS's common equity ratio, as defined, was 52%. Its total shareholder equity was approximately $5.9 billion, and total capitalization was approximately $11.2 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $4.5 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, 2019 and 2018 (dollars in millions):

Pinnacle West Consolidated

	2019	2018
Net cash flow provided by operating activities	$ 957	$ 1,277
Net cash flow used for investing activities	(1,131)	(1,193)
Net cash flow provided by (used for) financing activities	179	(92)
Net increase (decrease) in cash and cash equivalents	$ 5	$ (8)

Arizona Public Service Company

	2019	2018
Net cash flow provided by operating activities	$ 1,007	$ 1,255
Net cash flow used for investing activities	(1,136)	(1,187)
Net cash flow provided by (used for) financing activities	133	(76)
Net increase (decrease) in cash and cash equivalents	$ 4	$ (8)

Operating Cash Flows

2019 Compared with 2018. Pinnacle West's consolidated net cash provided by operating activities was $957 million in 2019 compared to $1,277 million in 2018. The decrease of $320 million in net cash provided is primarily due to lower cash receipts from electric revenues, higher payments for operations and maintenance, fuel and purchased power costs, property taxes, interest and higher pension contributions. The difference between APS and Pinnacle West's net cash provided by operating activities primarily relates to Pinnacle West's income tax cash payments to APS, offset by lower operations and maintenance expense at the parent.

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. 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. The minimum required funding takes into consideration the value of plan assets and our pension benefit obligations. Under ERISA, the qualified pension plan was 117% funded as of January 1, 2020 and 112% as of January 1, 2019. Under GAAP, the qualified pension plan was 97% funded as of January 1, 2020 and 90% funded as of January 1, 2019. See Note 8 for additional details. The assets in the plan are comprised of fixed-income, equity, real estate, and short-term investments. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We made contributions to our pension plan totaling $150 million in 2019 and $50 million in 2018. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to $100 million per year during the 2020-2022 period. With regard to contributions to our other postretirement benefit plan, we did not make a contribution in 2019 and 2018. We do not expect to make any contributions over the next three years to our other postretirement benefit plans. The Company was reimbursed $30 million in 2019 and $72 million in 2018 for prior years' retiree medical claims from the other postretirement benefit plan trust assets.

Investing Cash Flows

2019 Compared with 2018. Pinnacle West's consolidated net cash used for investing activities was $1,131 million in 2019 compared to $1,193 million in 2018. The decrease of $62 million in net cash used primarily related to decreased capital expenditures and active union employee medical claim reimbursements (see Note 20). The difference between APS and Pinnacle West's net cash used for investing activities primarily relates to Pinnacle West's investing cash activity related to 4CA.

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,		
	2020	**2021**	**2022**
APS			
Generation:			
Clean:			
Nuclear Generation	$ 131	$ 123	$ 123
Renewables and Energy Storage Systems ("ESS") (a)	121	490	671
Environmental	44	53	44
Other Generation	139	154	121
Distribution	554	444	446
Transmission	182	203	208
Other (b)	160	183	112
Total APS	$ 1,331	$ 1,650	$ 1,725

(a) APS Solar Communities program, energy storage, renewable projects and other clean energy projects
(b) Primarily information systems and facilities 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

2019 Compared with 2018. Pinnacle West's consolidated net cash provided by financing activities was $179 million in 2019 compared to $92 million of net cash used in 2018, an increase of $271 million in net cash provided. The increase in net cash provided by financing activities includes $647 million in higher issuances of long-term debt partially offset by higher long-term debt repayments of $418 million, a net increase in short term borrowings of $57 million and higher dividend payments of $21 million.

APS's consolidated net cash provided by financing activities was $133 million in 2019 compared to $76 million of net cash used in 2018, an increase of $209 million in net cash provided. The increase in net cash provided by financing activities includes $797 million in higher issuances of long-term debt partially offset by higher long-term debt repayments of $418 million, lower equity infusion of $150 million and higher dividend payments of $20 million.

Significant Financing Activities. On December 18, 2019, the Pinnacle West Board of Directors declared a dividend of $0.7825 per share of common stock, payable on March 2, 2020 to shareholders of record on February 3, 2020. During 2019, Pinnacle West increased its indicated annual dividend from $2.95 per share to $3.13 per share. For the year ended December 31, 2019, Pinnacle West's total dividends paid per share of common stock were $3.00 per share, which resulted in dividend payments of $329 million.

On February 26, 2019, APS entered into a $200 million term loan agreement that matures August 26, 2020. APS used the proceeds to repay existing indebtedness. Borrowings under the agreement bear interest at London Inter-bank Offered Rate ("LIBOR") plus 0.50% per annum.

On February 28, 2019, APS issued $300 million of 4.25% unsecured senior notes that mature on March 1, 2049. The net proceeds from the sale, together with funds made available from the term loan described above, were used to repay existing indebtedness.

On March 1, 2019, APS repaid at maturity $500 million aggregate principal amount of its 8.75% senior notes.

On August 19, 2019, APS issued $300 million of 2.6% unsecured senior notes that mature on August 15, 2029. The net proceeds from the sale were used to repay short-term indebtedness, consisting of commercial paper borrowings, and to replenish cash used to fund capital expenditures.

On November 20, 2019, APS issued $300 million of 3.5% unsecured senior notes that mature on December 1, 2049. The net proceeds from the sale were used to repay short-term indebtedness, consisting of commercial paper borrowings, to replenish cash used to fund capital expenditures, and to redeem, on December 30, 2019, $100 million of the $250 million aggregate principal amount of our 2.2% Notes due January 15, 2020.

On January 15, 2020, APS repaid at maturity the remaining $150 million of the $250 million aggregate principal amount of its 2.2% senior notes mentioned above.

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.

On May 9, 2019, Pinnacle West entered into a $50 million term loan agreement that matures May 7, 2020. Pinnacle West used the proceeds to refinance indebtedness under and terminate a prior $150 million revolving credit facility. Borrowings under the agreement bear interest at LIBOR plus 0.55% per annum. At December 31, 2019, Pinnacle West had $38 million in outstanding borrowings under the agreement.

At December 31, 2019, Pinnacle West had a $200 million revolving credit facility that matures in July 2023. 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. The facility is available to support Pinnacle West's $200 million commercial paper program, for bank borrowings or for issuances of letters of credits. At December 31, 2019, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and $77 million of commercial paper borrowings.

At December 31, 2019, APS had two revolving credit facilities totaling $1 billion, including a $500 million credit facility that matures in June 2022 and a $500 million facility that matures in July 2023. 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. These facilities are available to support APS's $500 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2019, APS had no commercial paper outstanding and no outstanding borrowings or letters of credit under its revolving credit facilities. See "Financial Assurances" in Note 11 for a discussion of APS's other outstanding letters of credit.

Other Financing Matters. See Note 17 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, 2019, the ratio was approximately 52% for Pinnacle West and 47% 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.

See Note 7 for further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of February 14, 2020 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 of time. 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 downward revision to our credit ratings.

	Moody's	Standard & Poor's	Fitch
Pinnacle West			
Corporate credit rating	A3	A-	A-
Senior unsecured	A3	BBB+	A-
Commercial paper	P-2	A-2	F2
Outlook	Negative	Stable	Negative
APS			
Corporate credit rating	A2	A-	A-
Senior unsecured	A2	A-	A
Commercial paper	P-1	A-2	F2
Outlook	Negative	Stable	Negative

Off-Balance Sheet Arrangements

See Note 19 for a discussion of the impacts on our financial statements of consolidating certain VIEs.

Contractual Obligations

The following table summarizes Pinnacle West's consolidated contractual requirements as of December 31, 2019 (dollars in millions):

	2020	2021-2022	2023-2024	Thereafter	Total
Long-term debt payments, including interest: (a)					
APS	$ 554	$ 398	$ 757	$ 7,405	$ 9,114
Pinnacle West	460	—	—	—	460
Total long-term debt payments, including interest	1,014	398	757	7,405	9,574
Short-term debt payments, including interest (b)	115	—	—	—	115
Fuel and purchased power commitments (c)	569	1,217	1,176	5,318	8,280
Renewable energy credits (d)	36	66	58	133	293
Purchase obligations (e)	21	20	21	196	258
Coal reclamation	17	33	37	88	175
Nuclear decommissioning funding requirements	2	4	4	50	60
Noncontrolling interests (f)	23	46	39	143	251
Operating lease payments (g)	15	20	10	39	84
Total contractual commitments	$ 1,812	$ 1,804	$ 2,102	$ 13,372	$ 19,090

(a) The long-term debt matures at various dates through 2049 and bears interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using average rates at December 31, 2019 (see Note 7).
(b) See Note 6 for further details.
(c) Our fuel and purchased power commitments include purchases of coal, electricity, natural gas, renewable energy, nuclear fuel, and natural gas transportation (see Notes 4 and 11).
(d) Contracts to purchase renewable energy credits in compliance with the RES (see Note 4).
(e) These contractual obligations include commitments for capital expenditures and other obligations.
(f) Payments to the noncontrolling interests relate to the Palo Verde sale leaseback (see Note 19).
(g) Commitments relating to purchased power lease contracts are included within the fuel and purchased power commitments line above (see Note 9).

This table excludes $43 million in unrecognized tax benefits because the timing of the future cash outflows is uncertain. Estimated minimum required pension contributions are zero for 2020, 2021 and 2022 (see Note 8).

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 $1,507 million of regulatory assets and $2,503 million of regulatory liabilities on the Consolidated Balance Sheets at December 31, 2019.

See Notes 1 and 4 for more information.

Pensions and Other Postretirement Benefit Accounting

Changes in our actuarial assumptions used in calculating our pension and other postretirement benefit liability and expense can have a significant impact on our earnings and financial position. The most relevant actuarial assumptions are the discount rate used to measure our liability and net periodic cost, 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.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2019 reported pension liability on the Consolidated Balance Sheets and our 2019 reported pension expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

	Increase (Decrease)	
Actuarial Assumption (a)	**Impact on Pension Liability**	**Impact on Pension Expense**
Discount rate:		
Increase 1%	$ (388)	$ (11)
Decrease 1%	471	14
Expected long-term rate of return on plan assets:		
Increase 1%	—	(22)
Decrease 1%	—	22

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

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2019 other postretirement benefit obligation and our 2019 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

	Increase (Decrease)	
Actuarial Assumption (a)	**Impact on Other Postretirement Benefit Obligation**	**Impact on Other Postretirement Benefit Expense**
Discount rate:		
Increase 1%	$ (104)	$ (1)
Decrease 1%	134	5
Healthcare cost trend rate (b):		
Increase 1%	124	9
Decrease 1%	(98)	(4)
Expected long-term rate of return on plan assets – pretax:		
Increase 1%	—	(4)
Decrease 1%	—	4

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

(b) This assumes a 1% change in the initial and ultimate healthcare cost trend rate.

See Note 8 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 trust 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 14 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, 2019 are described further in Note 12.

OTHER ACCOUNTING MATTERS

On January 1, 2019, we adopted new lease accounting guidance, ASU 2016-02, and related amendments. On July 1, 2019, we early adopted ASU 2018-15, relating to accounting for cloud computing implementation costs. On January 1, 2020, we adopted ASU 2016-13 and related amendments, relating to the measurement of credit losses on financial instruments. See Note 3 for additional information related to new accounting standards.

MARKET AND CREDIT RISKS

Market Risks

Our operations include managing market risks related to changes in interest rates, commodity prices and investments held by our nuclear decommissioning trust, 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 Note 14 and Note 20), 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, 2019 and 2018. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2019 and 2018 (dollars in millions):

Pinnacle West – Consolidated

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2019	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**
2020	2.06%	$ 115	2.16%	$ 350	2.23%	$ 450
2021	—	—	—	—	—	—
2022	—	—	—	—	—	—
2023	—	—	—	—	—	—
2024	—	—	—	—	3.78%	365
Years thereafter	—	—	1.54%	36	4.12%	4,475
Total		$ 115		$ 386		$ 5,290
Fair value		$ 115		$ 386		$ 5,808

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2018	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**
2019	2.99%	$ 76	—	$ —	8.75%	$ 500
2020	—	—	3.02%	150	2.23%	550
2021	—	—	—	—	—	—
2022	—	—	—	—	—	—
2023	—	—	—	—	—	—
Years thereafter	—	—	1.76%	36	4.25%	3,940
Total		$ 76		$ 186		$ 4,990
Fair value		$ 76		$ 186		$ 5,048

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, 2019 and 2018. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2019 and 2018 (dollars in millions):

APS — Consolidated

	Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2019	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**
2020	2.12%	$ 200	2.20%	$ 150
2021	—	—	—	—
2022	—	—	—	—
2023	—	—	—	—
2024	—	—	3.78%	365
Years thereafter	1.54%	36	4.12%	4,475
Total		$ 236		$ 4,990
Fair value		$ 236		$ 5,508

	Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2018	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**
2019	—	$ —	8.75%	$ 500
2020	—	—	2.20%	250
2021	—	—	—	—
2022	—	—	—	—
2023	—	—	—	—
Years thereafter	1.76%	36	4.25%	3,940
Total		$ 36		$ 4,690
Fair value		$ 36		$ 4,754

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 fuels. 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 derivative positions in 2019 and 2018 (dollars in millions):

	2019	2018
Mark-to-market of net positions at beginning of year	$ (58)	$ (91)
Decrease (Increase) in regulatory asset	(15)	31
Recognized in OCI:		
Mark-to-market losses realized during the period	2	2
Change in valuation techniques	—	—
Mark-to-market of net positions at end of year	$ (71)	$ (58)

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at December 31, 2019 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	2020	2021	2022	2023	2024	Total fair value
Observable prices provided by other external sources	$ (36)	$ (17)	$ (10)	$ (4)	$ —	$ (67)
Prices based on unobservable inputs	(2)	—	—	—	(2)	(4)
Total by maturity	$ (38)	$ (17)	$ (10)	$ (4)	$ (2)	$ (71)

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 at December 31, 2019 and 2018 (dollars in millions):

	December 31, 2019 Gain (Loss)		December 31, 2018 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	$ —	$ —	$ 1	$ (1)
Natural gas	55	(55)	44	(44)
Total	$ 55	$ (55)	$ 45	$ (45)

(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 17 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

See Note 13 for the selected quarterly financial data (unaudited) required to be presented in this Item.

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, 2019. The effectiveness of our internal control over financial reporting as of December 31, 2019 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 21, 2020

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, 2019 and 2018, 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, 2019, the related notes and the schedules 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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 Note 1 and Note 4 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.

Rates are subject to the rate-making policies of the ACC. Rates are determined and approved in regulatory proceedings based on an analysis of costs to provide utility service and a return on, and recovery of, investment in the utility business. Regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. 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.

We identified Regulatory Accounting, specifically the impact of rate regulation on the financial statements, as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory rate orders on the financial statements. Management judgments include continually assessing the likelihood of future recovery of regulatory assets and/or a disallowance of part of the cost of recently completed plant, by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. If future recovery of regulatory assets ceases to be probable or a disallowance becomes probable, it would result in a charge to earnings. Management judgments also include assessing the impact of potential ACC-ordered refunds to customers on regulatory liabilities. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the ACC, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the ACC included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs of recently completed plant and costs deferred as regulatory assets and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the initial recognition of amounts as property, plant, and equipment; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.

- We evaluated the Company's disclosures related to regulatory accounting, specifically the impact of rate regulation on the financial statements, including the balances recorded and regulatory developments.

- We read relevant regulatory rate orders issued by the ACC for APS and other public utilities in Arizona, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedence of the ACC's treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.

- We read management's preliminary rate filings submitted and testimony given to the ACC regarding the 2019 Retail Rate Case filed in October 2019 and monitored activity by intervenors, the ACC and its staff. The filing is still under review with the ACC. We read the filing and related testimony to assess the likelihood of recovery in future rates or of a future reduction in rates based on the information available as of our report date.

- 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 precedence set by the ACC under similar circumstances. For certain regulatory assets or liabilities where management's assessment is based on precedence 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.

/s/ Deloitte & Touche LLP

Phoenix, Arizona
February 21, 2020

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,		
	2019	2018	2017
OPERATING REVENUES (NOTE 2)	$ 3,471,209	$ 3,691,247	$ 3,565,296
OPERATING EXPENSES			
Fuel and purchased power	1,042,237	1,076,116	981,301
Operations and maintenance	941,616	1,036,744	949,107
Depreciation and amortization	590,929	582,354	534,118
Taxes other than income taxes	218,579	212,849	184,347
Other expenses	5,888	9,497	6,660
Total	2,799,249	2,917,560	2,655,533
OPERATING INCOME	671,960	773,687	909,763
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	31,431	52,319	47,011
Pension and other postretirement non-service credits - net (Note 8)	22,989	49,791	24,664
Other income (Note 18)	50,263	24,896	4,006
Other expense (Note 18)	(17,880)	(17,966)	(21,539)
Total	86,803	109,040	54,142
INTEREST EXPENSE			
Interest charges	235,251	243,465	219,796
Allowance for borrowed funds used during construction (Note 1)	(18,528)	(25,180)	(22,112)
Total	216,723	218,285	197,684
INCOME BEFORE INCOME TAXES	542,040	664,442	766,221
INCOME TAXES (Note 5)	(15,773)	133,902	258,272
NET INCOME	557,813	530,540	507,949
Less: Net income attributable to noncontrolling interests (Note 19)	19,493	19,493	19,493
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 538,320	$ 511,047	$ 488,456
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	112,443	112,129	111,839
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	112,758	112,550	112,367
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Net income attributable to common shareholders — basic	$ 4.79	$ 4.56	$ 4.37
Net income attributable to common shareholders — diluted	$ 4.77	$ 4.54	$ 4.35

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,		
	2019	2018	2017
NET INCOME	$ 557,813	$ 530,540	$ 507,949
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized loss, net of tax benefit (expense) of $0, ($78), and $24 (Note 17)	—	(78)	(35)
Reclassification of net realized loss, net of tax benefit of $375, $473, and $1,294 (Note 17)	1,137	1,527	2,225
Pension and other postretirement benefits activity, net of tax benefit (expense) of $3,452, ($1,585), and $693 (Note 8)	(10,525)	4,397	(3,370)
Total other comprehensive income (loss)	(9,388)	5,846	(1,180)
COMPREHENSIVE INCOME	548,425	536,386	506,769
Less: Comprehensive income attributable to noncontrolling interests	19,493	19,493	19,493
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 528,932	$ 516,893	$ 487,276

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

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

	December 31,	
	2019	2018
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 10,283	$ 5,766
Customer and other receivables	266,426	267,887
Accrued unbilled revenues	128,165	137,170
Allowance for doubtful accounts	(8,171)	(4,069)
Materials and supplies (at average cost)	331,091	269,065
Fossil fuel (at average cost)	14,829	25,029
Income tax receivable (Note 5)	21,727	—
Assets from risk management activities (Note 17)	515	1,113
Deferred fuel and purchased power regulatory asset (Note 4)	70,137	37,164
Other regulatory assets (Note 4)	133,070	129,738
Other current assets	61,958	56,128
Total current assets	1,030,030	924,991
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Notes 14 and 20)	1,010,775	851,134
Other special use funds (Notes 14 and 20)	245,095	236,101
Other assets	96,953	103,247
Total investments and other assets	1,352,823	1,190,482
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 7 and 10)		
Plant in service and held for future use	19,836,292	18,736,628
Accumulated depreciation and amortization	(6,637,857)	(6,366,014)
Net	13,198,435	12,370,614
Construction work in progress	808,133	1,170,062
Palo Verde sale leaseback, net of accumulated depreciation of $249,144 and $245,275 (Note 19)	101,906	105,775
Intangible assets, net of accumulated amortization of $647,276 and $591,202	290,564	262,902
Nuclear fuel, net of accumulated amortization of $137,330 and $137,850	123,500	120,217
Total property, plant and equipment	14,522,538	14,029,570
DEFERRED DEBITS		
Regulatory assets (Notes 1, 4 and 5)	1,304,073	1,342,941
Operating lease right-of-use assets (Note 9)	145,813	—
Assets for other postretirement benefits (Note 8)	90,570	46,906
Other	33,400	129,312
Total deferred debits	1,573,856	1,519,159
TOTAL ASSETS	$ 18,479,247	$ 17,664,202

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

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

	December 31,	
	2019	2018
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 346,448	$ 277,336
Accrued taxes	144,899	154,819
Accrued interest	53,534	61,107
Common dividends payable	87,982	82,675
Short-term borrowings (Note 6)	114,675	76,400
Current maturities of long-term debt (Note 7)	800,000	500,000
Customer deposits	64,908	91,174
Liabilities from risk management activities (Note 17)	38,946	35,506
Liabilities for asset retirements (Note 12)	11,025	19,842
Operating lease liabilities (Note 9)	12,713	—
Regulatory liabilities (Note 4)	234,912	165,876
Other current liabilities	168,323	184,229
Total current liabilities	2,078,365	1,648,964
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 7)	4,832,558	4,638,232
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 5)	1,992,339	1,807,421
Regulatory liabilities (Notes 1, 4, 5 and 8)	2,267,835	2,325,976
Liabilities for asset retirements (Note 12)	646,193	706,703
Liabilities for pension benefits (Note 8)	280,185	443,170
Liabilities from risk management activities (Note 17)	33,186	24,531
Customer advances	215,330	137,153
Coal mine reclamation	165,695	212,785
Deferred investment tax credit	196,468	200,405
Unrecognized tax benefits (Note 5)	6,189	22,517
Operating lease liabilities (Note 9)	51,872	—
Other	159,844	147,640
Total deferred credits and other	6,015,136	6,028,301
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 112,540,126 and 112,159,896 issued at respective dates	2,659,561	2,634,265
Treasury stock at cost; 103,546 shares at end of 2019 and 58,135 shares at end of 2018	(9,427)	(4,825)
Total common stock	2,650,134	2,629,440
Retained earnings	2,837,610	2,641,183
Accumulated other comprehensive loss (Note 21)	(57,096)	(47,708)
Total shareholders' equity	5,430,648	5,222,915
Noncontrolling interests (Note 19)	122,540	125,790
Total equity	5,553,188	5,348,705
TOTAL LIABILITIES AND EQUITY	$ 18,479,247	$ 17,664,202

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,		
	2019	2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 557,813	$ 530,540	$ 507,949
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	664,140	650,955	610,629
Deferred fuel and purchased power	(82,481)	(78,277)	(48,405)
Deferred fuel and purchased power amortization	49,508	116,750	(14,767)
Allowance for equity funds used during construction	(31,431)	(52,319)	(47,011)
Deferred income taxes	(1,479)	117,355	248,164
Deferred investment tax credit	(3,938)	(5,170)	(4,587)
Change in derivative instruments fair value	—	—	(373)
Stock compensation	18,376	19,547	20,502
Changes in current assets and liabilities:			
Customer and other receivables	(12,789)	37,530	(93,797)
Accrued unbilled revenues	9,005	(24,736)	(4,485)
Materials, supplies and fossil fuel	(51,826)	(6,103)	(6,683)
Income tax receivable	(21,727)	—	3,751
Other current assets	(3,507)	33,844	(10,580)
Accounts payable	50,641	(14,602)	(23,769)
Accrued taxes	(9,920)	6,597	9,982
Other current liabilities	(84,651)	28,174	19,154
Change in margin and collateral accounts — assets	(247)	143	(300)
Change in margin and collateral accounts — liabilities	(125)	(2,211)	(533)
Change in unrecognized tax benefits	2,704	(1,235)	5,891
Change in long-term regulatory liabilities	124,221	(109,284)	45,764
Change in other long-term assets	(82,895)	78,604	(68,480)
Change in other long-term liabilities	(132,666)	(48,958)	(29,980)
Net cash flow provided by operating activities	956,726	1,277,144	1,118,036
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,191,447)	(1,178,169)	(1,408,774)
Contributions in aid of construction	70,693	27,716	23,708
Allowance for borrowed funds used during construction	(18,528)	(25,180)	(22,112)
Proceeds from nuclear decommissioning trust sales and other special use funds	719,034	653,033	542,246
Investment in nuclear decommissioning trust and other special use funds	(722,181)	(672,165)	(544,527)
Other	11,452	1,941	(19,078)
Net cash flow used for investing activities	(1,130,977)	(1,192,824)	(1,428,537)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	1,092,188	445,245	848,239
Repayment of long-term debt	(600,000)	(182,000)	(125,000)
Short-term borrowings and (repayments) — net	54,275	(7,000)	(107,800)
Short-term debt borrowings under revolving credit facility	49,000	45,000	58,000
Short-term debt repayments under revolving credit facility	(65,000)	(57,000)	(32,000)
Dividends paid on common stock	(329,643)	(308,892)	(289,793)
Common stock equity issuance and purchases - net	692	(5,055)	(13,390)
Distributions to noncontrolling interests	(22,744)	(22,744)	(22,744)
Net cash flow provided by (used for) financing activities	178,768	(92,446)	315,512
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	4,517	(8,126)	5,011
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	5,766	13,892	8,881

CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 10,283	$ 5,766	$ 13,892

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, 2016	111,392,053	$ 2,596,030	(55,317)	$ (4,133)	$ 2,255,547	$ (43,822)	$ 132,290	$ 4,935,912
Net income		—		—	488,456	—	19,493	507,949
Other comprehensive loss		—		—	—	(1,180)	—	(1,180)
Dividends on common stock ($2.70 per share)		—		—	(301,492)	—	—	(301,492)
Issuance of common stock	424,117	18,775		—	—	—	—	18,775
Purchase of treasury stock (a)		—	(216,911)	(17,755)	—	—	—	(17,755)
Reissuance of treasury stock for stock-based compensation and other		—	207,765	16,264	—	—	—	16,264
Capital activities by noncontrolling interests		—		—	—	—	(22,743)	(22,743)
Balance, December 31, 2017	111,816,170	2,614,805	(64,463)	(5,624)	2,442,511	(45,002)	129,040	5,135,730
Net income		—		—	511,047	—	19,493	530,540
Other comprehensive income		—		—	—	5,846	—	5,846
Dividends on common stock ($2.87 per share)		—		—	(320,927)	—	—	(320,927)
Issuance of common stock	343,726	19,460		—	—	—	—	19,460
Purchase of treasury stock (a)		—	(129,903)	(10,338)	—	—	—	(10,338)
Reissuance of treasury stock for stock-based compensation and other		—	136,231	11,137	—	—	—	11,137
Capital activities by noncontrolling interests		—		—	—	—	(22,743)	(22,743)
Reclassification of income tax effects related to new tax reform (b)		—		—	8,552	(8,552)	—	—
Balance, December 31, 2018	112,159,896	2,634,265	(58,135)	(4,825)	2,641,183	(47,708)	125,790	5,348,705
Net income		—		—	538,320	—	19,493	557,813
Other comprehensive loss		—		—	—	(9,388)	—	(9,388)
Dividends on common stock ($3.04 per share)		—		—	(341,893)	—	—	(341,893)
Issuance of common stock	380,230	25,296		—	—	—	—	25,296
Purchase of treasury stock (a)		—	(121,493)	(11,202)	—	—	—	(11,202)
Reissuance of treasury stock for stock-based compensation and other		—	76,082	6,600	—	—	—	6,600
Capital activities by noncontrolling interests		—		—	—	—	(22,743)	(22,743)
Balance, December 31, 2019	112,540,126	$ 2,659,561	(103,546)	$ (9,427)	$ 2,837,610	$ (57,096)	$ 122,540	$ 5,553,188

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

(b) In 2018, the Company adopted new accounting guidance and elected to reclassify income tax effects of the Tax Cuts and Jobs Act of 2017 (the "Tax Act") on items within accumulated other comprehensive income to retained earnings.

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, 2019. The effectiveness of our internal control over financial reporting as of December 31, 2019 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 21, 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders 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, 2019 and 2018, 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, 2019, 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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.

/s/ Deloitte & Touche LLP

Phoenix, Arizona
February 21, 2020

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,		
	2019	**2018**	**2017**
OPERATING REVENUES (NOTE 2)	$ 3,471,209	$ 3,688,342	$ 3,557,652
OPERATING EXPENSES			
Fuel and purchased power	1,042,237	1,094,020	992,744
Operations and maintenance	926,716	969,227	917,983
Depreciation and amortization	590,844	580,694	532,423
Taxes other than income taxes	218,540	212,136	183,254
Other expense	5,888	2,497	6,709
Total	2,784,225	2,858,574	2,633,113
OPERATING INCOME	686,984	829,768	924,539
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	31,431	52,319	47,011
Pension and other postretirement non-service credits - net (Note 8)	24,529	51,242	24,371
Other income (Note 18)	46,884	22,746	3,013
Other expense (Note 18)	(12,990)	(15,292)	(13,913)
Total	89,854	111,015	60,482
INTEREST EXPENSE			
Interest charges	220,174	231,391	214,163
Allowance for borrowed funds used during construction (Note 1)	(18,528)	(25,180)	(22,112)
Total	201,646	206,211	192,051
INCOME BEFORE INCOME TAXES	575,192	734,572	792,970
INCOME TAXES (Note 5)	(9,572)	144,814	269,168
NET INCOME	584,764	589,758	523,802
Less: Net income attributable to noncontrolling interests (Note 19)	19,493	19,493	19,493
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 565,271	$ 570,265	$ 504,309

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,		
	2019	2018	2017
NET INCOME	$ 584,764	$ 589,758	$ 523,802
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized loss, net of tax benefit (expense) of $0, ($78), and $24 (Note 17)	—	(78)	(35)
Reclassification of net realized loss, net of tax benefit of $375, $473, and $1,294 (Note 17)	1,137	1,527	2,225
Pension and other postretirement benefits activity, net of tax benefit (expense) of $3,136, ($1,159), and $977 (Note 8)	(9,552)	3,465	(3,750)
Total other comprehensive income (loss)	(8,415)	4,914	(1,560)
COMPREHENSIVE INCOME	576,349	594,672	522,242
Less: Comprehensive income attributable to noncontrolling interests	19,493	19,493	19,493
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 556,856	$ 575,179	$ 502,749

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

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

	December 31, 2019	December 31, 2018
ASSETS		
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 7 and 10)		
Plant in service and held for future use	$ 19,832,805	$ 18,733,142
Accumulated depreciation and amortization	(6,634,597)	(6,362,771)
Net	13,198,208	12,370,371
Construction work in progress	808,133	1,170,062
Palo Verde sale leaseback, net of accumulated depreciation of $249,144 and $245,275 (Note 19)	101,906	105,775
Intangible assets, net of accumulated amortization of $646,142 and $590,069	290,409	262,746
Nuclear fuel, net of accumulated amortization of $137,330 and $137,850	123,500	120,217
Total property, plant and equipment	14,522,156	14,029,171
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Notes 14 and 20)	1,010,775	851,134
Other special use funds (Notes 14 and 20)	245,095	236,101
Other assets	43,781	40,817
Total investments and other assets	1,299,651	1,128,052
CURRENT ASSETS		
Cash and cash equivalents	10,169	5,707
Customer and other receivables	255,479	257,654
Accrued unbilled revenues	128,165	137,170
Allowance for doubtful accounts	(8,171)	(4,069)
Materials and supplies (at average cost)	331,091	269,065
Fossil fuel (at average cost)	14,829	25,029
Income tax receivable (Note 5)	7,313	—
Assets from risk management activities (Note 17)	515	1,113
Deferred fuel and purchased power regulatory asset (Note 4)	70,137	37,164
Other regulatory assets (Note 4)	133,070	129,738
Other current assets	38,895	35,111
Total current assets	981,492	893,682
DEFERRED DEBITS		
Regulatory assets (Notes 1, 4, and 5)	1,304,073	1,342,941
Operating lease right-of-use assets (Note 9)	144,024	—
Assets for other postretirement benefits (Note 8)	86,736	43,212
Other	32,591	128,265
Total deferred debits	1,567,424	1,514,418
TOTAL ASSETS	$ 18,370,723	$ 17,565,323

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

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

	December 31,	
	2019	**2018**
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	2,721,696	2,721,696
Retained earnings	3,011,927	2,788,256
Accumulated other comprehensive loss (Note 21)	(35,522)	(27,107)
Total shareholder equity	5,876,263	5,661,007
Noncontrolling interests (Note 19)	122,540	125,790
Total equity	5,998,803	5,786,797
Long-term debt less current maturities (Note 7)	4,833,133	4,189,436
Total capitalization	10,831,936	9,976,233
CURRENT LIABILITIES		
Current maturities of long-term debt (Note 7)	350,000	500,000
Accounts payable	338,006	266,277
Accrued taxes	136,328	176,357
Accrued interest	52,619	60,228
Common dividends payable	88,000	82,700
Customer deposits	64,908	91,174
Liabilities from risk management activities (Note 17)	38,946	35,506
Liabilities for asset retirements (Note 12)	11,025	19,842
Operating lease liabilities (Note 9)	12,549	—
Regulatory liabilities (Note 4)	234,912	165,876
Other current liabilities	164,736	178,137
Total current liabilities	1,492,029	1,576,097
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 5)	2,033,096	1,812,664
Regulatory liabilities (Notes 1, 4, 5 and 8)	2,267,835	2,325,976
Liabilities for asset retirements (Note 12)	646,193	706,703
Liabilities for pension benefits (Note 8)	262,243	425,404
Liabilities from risk management activities (Note 17)	33,186	24,531
Customer advances	215,330	137,153
Coal mine reclamation	165,695	212,785
Deferred investment tax credit	196,468	200,405
Unrecognized tax benefits (Note 5)	40,188	41,861
Operating lease liabilities (Note 9)	50,092	—
Other	136,432	125,511
Total deferred credits and other	6,046,758	6,012,993
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
TOTAL LIABILITIES AND EQUITY	$ 18,370,723	$ 17,565,323

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,		
	2019	2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 584,764	$ 589,758	$ 523,802
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	664,055	649,295	608,935
Deferred fuel and purchased power	(82,481)	(78,277)	(48,405)
Deferred fuel and purchased power amortization	49,508	116,750	(14,767)
Allowance for equity funds used during construction	(31,431)	(52,319)	(47,011)
Deferred income taxes	48,367	59,927	249,465
Deferred investment tax credit	(3,938)	(5,170)	(4,587)
Change in derivative instruments fair value	—	—	(373)
Changes in current assets and liabilities:			
Customer and other receivables	(12,075)	35,406	(68,040)
Accrued unbilled revenues	9,005	(24,736)	(4,485)
Materials, supplies and fossil fuel	(51,826)	(6,206)	(6,503)
Income tax receivable	(7,313)	—	11,174
Other current assets	(1,461)	31,707	(6,775)
Accounts payable	53,258	(15,608)	(26,561)
Accrued taxes	(40,029)	19,008	26,773
Other current liabilities	(82,138)	25,070	27,912
Change in margin and collateral accounts — assets	(247)	143	(300)
Change in margin and collateral accounts — liabilities	(125)	(2,211)	(533)
Change in unrecognized tax benefits	2,704	(1,235)	5,891
Change in long-term regulatory liabilities	124,221	(109,284)	45,764
Change in other long-term assets	(85,725)	77,952	(78,540)
Change in other long-term liabilities	(129,682)	(55,169)	(31,106)
Net cash flow provided by operating activities	1,007,411	1,254,801	1,161,730
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,191,447)	(1,169,061)	(1,381,930)
Contributions in aid of construction	70,693	27,716	23,708
Allowance for borrowed funds used during construction	(18,528)	(25,180)	(22,112)
Proceeds from nuclear decommissioning trust sales and other special use funds	719,034	653,033	542,246
Investment in nuclear decommissioning trust and other special use funds	(722,181)	(672,165)	(544,527)
Other	6,336	(1,789)	(18,538)
Net cash flow used for investing activities	(1,136,093)	(1,187,446)	(1,401,153)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	1,092,188	295,245	549,478
Repayment of long-term debt	(600,000)	(182,000)	—
Short-term borrowings and (repayments) — net	—	—	(135,500)
Short-term debt borrowings under revolving credit facility	—	25,000	—
Short-term debt repayments under revolving credit facility	—	(25,000)	—
Dividends paid on common stock	(336,300)	(316,000)	(296,800)
Equity infusion from Pinnacle West	—	150,000	150,000
Noncontrolling interests	(22,744)	(22,744)	(22,744)
Net cash flow provided by (used for) financing activities	133,144	(75,499)	244,434
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	4,462	(8,144)	5,011
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	5,707	13,851	8,840
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 10,169	$ 5,707	$ 13,851

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, 2016	71,264,947	$ 178,162	$ 2,421,696	$ 2,331,245	$ (25,423)	$ 132,290	$ 5,037,970
Equity infusion from Pinnacle West		—	150,000	—	—	—	150,000
Net income		—	—	504,309	—	19,493	523,802
Other comprehensive loss		—	—	—	(1,560)	—	(1,560)
Dividends on common stock		—	—	(301,600)	—	—	(301,600)
Capital activities by noncontrolling interests		—	—	—	—	(22,743)	(22,743)
Balance, December 31, 2017	71,264,947	178,162	2,571,696	2,533,954	(26,983)	129,040	5,385,869
Equity infusion from Pinnacle West		—	150,000	—	—	—	150,000
Net income		—	—	570,265	—	19,493	589,758
Other comprehensive income		—	—	—	4,914	—	4,914
Dividends on common stock		—	—	(321,001)	—	—	(321,001)
Reclassifications of income tax effects related to new tax reform (a)		—	—	5,038	(5,038)	—	—
Capital activities by noncontrolling interests		—	—	—	—	(22,743)	(22,743)
Balance, December 31, 2018	71,264,947	178,162	2,721,696	2,788,256	(27,107)	125,790	5,786,797
Net income		—	—	565,271	—	19,493	584,764
Other comprehensive loss		—	—	—	(8,415)	—	(8,415)
Dividends on common stock		—	—	(341,600)	—	—	(341,600)
Capital activities by noncontrolling interests		—	—	—	—	(22,743)	(22,743)
Balance, December 31, 2019	71,264,947	$ 178,162	$ 2,721,696	$ 3,011,927	$ (35,522)	$ 122,540	$ 5,998,803

(a) In 2018, the Company adopted new accounting guidance and elected to reclassify income tax effects of the Tax Act on items within accumulated other comprehensive income to retained earnings.

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 11 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 VIEs for which we are the primary beneficiary. We determine whether we are the primary beneficiary of a VIE through a qualitative analysis that identifies which variable interest holder has the controlling financial interest in the VIE. In performing our primary beneficiary analysis, we consider all relevant facts and circumstances, including the design and activities of the VIE, the terms of the contracts the VIE has entered into, and which parties participated significantly in the design or redesign of the entity. We continually evaluate our primary beneficiary conclusions to determine if changes have occurred which would impact our primary beneficiary assessments. We have determined that APS is the primary beneficiary of certain VIE lessor trusts relating to the Palo Verde sale leaseback, and therefore APS consolidates these entities. See Note 19 for additional information.

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 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 4 for additional information.

Electric Revenues

On January 1, 2018, we adopted new revenue guidance ASU 2014-09, Revenue from contracts with customers; accordingly our 2019 and 2018 electric 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.

Some of our cost recovery mechanisms are 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 4 for additional information.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of existing accounts receivable that will ultimately be uncollectible. The allowance is calculated by applying an estimated write-off factor to utility revenues. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management's best estimate of future collections success given the existing collections environment.

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
- allowance for funds used during construction.

Pinnacle West's property, plant and equipment included in the December 31, 2019 and 2018 Consolidated Balance Sheets is composed of the following (dollars in thousands):

Property, Plant and Equipment:	2019	2018
Generation	$ 8,916,872	$ 8,285,514
Transmission	3,095,907	3,033,579
Distribution	6,690,697	6,378,345
General plant	1,132,816	1,039,190
Plant in service and held for future use	19,836,292	18,736,628
Accumulated depreciation and amortization	(6,637,857)	(6,366,014)
Net	13,198,435	12,370,614
Construction work in progress	808,133	1,170,062
Palo Verde sale leaseback, net of accumulated depreciation	101,906	105,775
Intangible assets, net of accumulated amortization	290,564	262,902
Nuclear fuel, net of accumulated amortization	123,500	120,217
Total property, plant and equipment	$ 14,522,538	$ 14,029,570

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 12 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 asset retirement obligations. 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, 2019 were as follows:

- Fossil plant — 17 years;
- Nuclear plant — 22 years;
- Other generation — 21 years;
- Transmission — 40 years;
- Distribution — 34 years; and
- General plant — 8 years.

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. Depreciation expense was $522 million in 2019, $486 million in 2018, and $453 million in 2017. For the years 2017 through 2019, the depreciation rates ranged from a low of 0.18% to a high of 24.49%. The weighted-average depreciation rate was 2.81% in 2019, 2.81% in 2018, and 2.80% in 2017.

Asset Retirement Obligations

APS has asset retirement obligations for its Palo Verde nuclear facilities and certain other generation assets. The Palo Verde asset retirement obligation 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 asset retirement obligations 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 asset retirement obligations 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 asset retirement obligation 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 12 for further information on Asset Retirement Obligations.

Allowance for Funds Used During Construction

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

AFUDC was calculated by using a composite rate of 6.98% for 2019, 7.03% for 2018, and 6.68% for 2017. 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

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 market, 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 7 for additional information.

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

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

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

See Note 14 for additional information about fair value measurements.

Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and in interest rates. We manage risks associated with market volatility by utilizing various physical and financial instruments including futures, forwards, options and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and fuels. 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 17 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. 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 8 for additional information on pension and other postretirement benefits.

Nuclear Fuel

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

APS also charges nuclear fuel expense for the interim storage and permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel and charged APS $0.001 per kWh of nuclear generation through May 2014, at which point the DOE reduced the fee to zero. In accordance with a settlement agreement with the DOE in August 2014, we now accrue a receivable and an offsetting regulatory liability through the settlement period ending December of 2019. See Note 11 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 5 for additional discussion.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cash and Cash Equivalents

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

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

	Year ended December 31,		
	2019	2018	2017
Cash paid during the period for:			
Income taxes, net of refunds	$ 12,535	$ 21,173	$ 2,186
Interest, net of amounts capitalized	218,664	208,479	189,288
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 141,297	$ 132,620	$ 130,404
Dividends declared but not paid	87,982	82,675	77,667
Right-of-use operating lease assets obtained in exchange for operating lease liabilities	11,262	—	—
Sale of 4CA 7% interest in Four Corners	—	68,907	—

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

	Year ended December 31,		
	2019	2018	2017
Cash paid (received) during the period for:			
Income taxes, net of refunds	$ (15,042)	$ 77,942	$ (14,098)
Interest, net of amounts capitalized	204,261	196,419	184,210
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 141,297	$ 132,620	$ 130,057
Dividends declared but not paid	88,000	82,700	77,700
Right-of-use operating lease assets obtained in exchange for operating lease liabilities	11,262	—	—

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 $66 million in 2019, $68 million in 2018, and $72 million in 2017. Estimated amortization expense on existing intangible assets over the next five years is $68 million in 2020, $52 million in 2021, $41 million in 2022, $32 million in 2023, and $22 million in 2024. At December 31, 2019, the weighted-average remaining amortization period for intangible assets was 8 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).

Bright Canyon 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 account and active union employee medical account, are accounted for in accordance with guidance on accounting for investments in debt and equity securities. See Notes 14 and 20 for more information on these investments.

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, 2019, 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,		Year Ended December 31,	
	2019		2018	
Retail Electric Service				
Residential	$	1,761,122	$	1,867,370
Non-Residential		1,509,514		1,628,891
Wholesale Energy Sales		121,805		109,198
Transmission Services for Others		62,460		60,261
Other Sources		16,308		25,527
Total Operating Revenues	$	3,471,209	$	3,691,247

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Retail Electric Revenue. Pinnacle West's retail electric revenue is generated by our 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 15 days of when the services are billed.

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 generation into the wholesale markets 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, 2019 and 2018 were $3,415 million and $3,644 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, 2019 and 2018, our revenues that do not qualify as revenue from contracts with customers were $56 million and $47 million, respectively. This relates primarily 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 4 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, 2019 and 2018.

3. New Accounting Standards

Standards Adopted in 2019

ASU 2016-02, Leases

In February 2016, a new lease accounting standard was issued. This new standard supersedes the existing lease accounting model, and modifies both lessee and lessor accounting. The new standard requires a lessee to reflect most operating lease arrangements on the balance sheet by recording a right-of-use asset and a lease liability that is initially measured at the present value of lease payments. Among other changes, the new standard also modifies the definition of a lease, and requires expanded lease disclosures. Since the issuance of the new lease standard, additional lease related guidance has been issued relating to land easements and how entities may elect to account for these arrangements at transition, among other items. The new lease standard and related amendments were effective for us on January 1, 2019, with early application permitted. The standard must be adopted using a modified retrospective approach with a cumulative-effect adjustment to the opening balance of retained earnings determined at either the date of adoption, or the earliest period presented in the financial statements. The standard includes various optional practical expedients provided to facilitate transition. We adopted this standard, and related amendments, on January 1, 2019. See Note 9 for additional information.

ASU 2018-15, Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract

In August 2018, a new accounting standard was issued that clarifies how customers in a cloud computing service arrangement should account for implementation costs associated with the arrangement. To determine which implementation costs should be capitalized, the new guidance aligns the accounting with existing guidance pertaining to internal-use software. As a result of this new standard, certain cloud computing service arrangement implementation costs will now be subject to capitalization and amortized on a straight-line basis over the cloud computing service arrangement term. The new standard was effective for us on January 1, 2020, with early application permitted, and may have been applied using either a retrospective or prospective transition approach. On July 1, 2019, we early adopted this new accounting standard using the prospective approach. The adoption did not have a material impact on our financial statements.

Standard Adopted in 2020

ASU 2016-13, Financial Instruments: Measurement of Credit Losses

In June 2016, a new accounting standard was issued that amends the measurement of credit losses on certain financial instruments. The new standard requires entities to use a current expected credit loss model to measure impairment of certain investments in debt securities, trade accounts receivables, and other financial instruments. Since the issuance of the new standard, various guidance has been issued that amends the new standard, including clarifications of certain aspects of the standard and targeted transition relief, among other changes. The new standard and related amendments were effective for us on January 1, 2020, and must be adopted using a modified retrospective approach for certain aspects of the standard, and a prospective approach for other aspects of the standard. We adopted the standard on January 1, 2020 using primarily the modified retrospective approach. While the adoption of this guidance changed our process and methodology for determining credit losses, these changes did not have a material impact on our financial statements.

4. Regulatory Matters

2019 Retail Rate Case Filing with the Arizona Corporation Commission

On October 31, 2019, APS filed an application with the ACC for an annual increase in retail base rates of $69 million. This amount includes recovery of the deferral and rate base effects of the Four Corners selective catalytic reduction ("SCR") project that is currently the subject of a separate proceeding (see "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 TEAM. The proposed total 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 are:

- a test year comprised of twelve 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:

	Capital Structure	Cost of Capital
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;
- 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 MW of medium and large commercial customers;

- 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 Plant (see "Navajo Plant" below).

APS requested that the increase become effective December 1, 2020. The hearing for this rate case is currently scheduled to begin in July 2020. APS cannot predict the outcome of its request.

2016 Retail Rate Case Filing with the Arizona Corporation Commission

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, the Residential Utility Consumer Office, 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 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. The average annual customer bill impact under the 2017 Settlement Agreement was calculated as an increase of 3.28% (the average annual bill impact for a typical APS residential customer was calculated as an increase of 4.54%).

Other key provisions of the agreement include the following:

- an agreement by APS not to file another general retail rate case application before June 1, 2019;
- an authorized return on common equity of 10.0%;
- a capital structure comprised of 44.2% debt and 55.8% common equity;
- a cost deferral order for potential future recovery in APS's next general retail rate case for the construction and operating costs APS incurs for its Ocotillo modernization project;
- a cost deferral and procedure to allow APS to request rate adjustments prior to its next general retail rate case related to its share of the construction costs associated with installing SCR equipment at Four Corners;
- a deferral for future recovery (or credit to customers) of the Arizona property tax expense above or below a specified test year level caused by changes to the applicable Arizona property tax rate;
- an expansion of the PSA to include certain environmental chemical costs and third-party energy storage costs;
- a new AZ Sun II program (now known as APS Solar Communities) for utility-owned solar distributed generation ("DG") with the purpose of expanding access to rooftop solar for low and moderate income Arizonans, recoverable through the RES, to be no less than $10 million per year in capital costs, and not more than $15 million per year in capital costs;
- an increase to the per kWh cap for the environmental improvement surcharge from $0.00016 to $0.00050 and the addition of a balancing account;
- rate design changes, including:
    - a change in the on-peak time of use period from noon - 7 p.m. to 3 p.m. - 8 p.m. Monday through Friday, excluding holidays;
    - non-grandfathered DG customers would be required to select a rate option that has time of use rates and either a new grid access charge or demand component;
    - a Resource Comparison Proxy ("RCP") for exported energy of 12.9 cents per kWh in year one; and

- an agreement by APS not to pursue any new self-build generation (with certain exceptions) having an in-service date prior to January 1, 2022 (extended to December 31, 2027 for combined-cycle generating units), unless expressly authorized by the ACC.

Through a separate agreement, APS, industry representatives, and solar advocates committed to stand by the 2017 Settlement Agreement and refrain from seeking to undermine it through ballot initiatives, legislation or advocacy at the ACC.

On August 15, 2017, the ACC approved (by a vote of 4-1), the 2017 Settlement Agreement without material modifications. 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"), which is subject to requests for rehearing and potential appeal. The new rates went into effect on August 19, 2017.

On January 3, 2018, an APS customer filed a petition with the ACC that was determined by the ACC Staff to be a complaint filed pursuant to Arizona Revised Statute §40-246 (the "Complaint") and not a request for rehearing. Arizona Revised Statute §40-246 requires the ACC to hold a hearing regarding any complaint alleging that a public service corporation is in violation of any commission order or that the rates being charged are not just and reasonable if the complaint is signed by at least twenty-five customers of the public service corporation. The Complaint alleged that APS is "in violation of commission order" [sic]. On February 13, 2018, the complainant filed an amended Complaint alleging that the rates and charges in the 2017 Rate Case Decision are not just and reasonable. The complainant requested that the ACC hold a hearing on the amended Complaint to determine if the average bill impact on residential customers of the rates and charges approved in the 2017 Rate Case Decision is greater than 4.54% (the average annual bill impact for a typical APS residential customer estimated by APS) and, if so, what effect the alleged greater bill impact has on APS's revenues and the overall reasonableness and justness of APS's rates and charges, in order to determine if there is sufficient evidence to warrant a full-scale rate hearing. The ACC held a hearing on this matter beginning in September 2018 and the hearing was concluded on October 1, 2018. On April 9, 2019, the Administrative Law Judge issued a Recommended Opinion and Order recommending that the Complaint be dismissed. The ACC considered the matter at its April and May 2019 open meetings, but no decision was issued. On July 3, 2019, the Administrative Law Judge issued an amendment to the Recommended Opinion and Order that incorporated the requirements of the rate review of the 2017 Rate Case Decision (see below discussion regarding the rate review). On July 10, 2019, the ACC reconsidered the matter and adopted the Administrative Law Judge's amended Recommended Opinion and Order along with several ACC Commissioner amendments and an amendment incorporating the results of the rate review and resolved the Complaint.

On December 24, 2018, certain ACC Commissioners filed a letter stating that because the ACC had received a substantial number of complaints that the rate increase authorized by the 2017 Rate Case Decision was much more than anticipated, they believe there is a possibility that APS is earning more than was authorized by the 2017 Rate Case Decision. Accordingly, the ACC Commissioners requested the ACC Staff to perform a rate review of APS using calendar year 2018 as a test year and file a report by May 3, 2019. The ACC Commissioners also asked the ACC Staff to evaluate APS's efforts to educate its customers regarding the new rates approved in the 2017 Rate Case Decision. On April 23, 2019, the ACC Staff indicated that they would need additional time beyond May 3, 2019 to file the requested report.

On June 4, 2019, the ACC Staff filed a proposed order regarding the rate review of the 2017 Rate Case Decision. On June 11, 2019, the ACC Commissioners approved the proposed ACC Staff order with amendments. The key provisions of the amended order include the following:

- APS must file a rate case no later than October 31, 2019, using a June 30, 2019 test-year;

- until the conclusion of the rate case being filed no later than October 31, 2019, APS must provide information on customer bills that shows how much a customer would pay on their most economical rate given their actual usage during each month;
- APS customers can switch rate plans during an open enrollment period of six months;
- APS must identify customers whose bills have increased by more than 9% and that are not on the most economical rate and provide such customers with targeted education materials and an opportunity to switch rate plans;
- APS must provide grandfathered net metering customers on legacy demand rates an opportunity to switch to another legacy rate to enable such customers to fully benefit from legacy net metering rates;
- APS must fund and implement a supplemental customer education and outreach program to be developed with and administered by ACC Staff and a third-party consultant; and
- APS must fund and organize, along with the third-party consultant, a stakeholder group to suggest better ways to communicate the impact of changes to adjustor cost recovery mechanisms (see below for discussion on cost recovery mechanisms), including more effective ways to educate customers on rate plans and to reduce energy usage.

APS cannot predict the outcome or impact of the rate case filed on October 31, 2019. APS is assessing the impact to its financial statements of the implementation of the other key provisions of the amended order regarding the rate review and cannot predict at this time whether they will have a material impact on its financial position, results of operations or cash flows.

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.

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 June 30, 2017, APS filed its 2018 RES Implementation Plan and proposed a budget of approximately $90 million. APS's budget request supports existing approved projects and commitments and includes the anticipated transfer of specific revenue requirements into base rates in accordance with the 2017 Settlement Agreement and also requests a permanent waiver of the residential distributed energy requirement for 2018 contained in the RES rules. APS's 2018 RES budget request was lower than the 2017 RES budget due in part to a certain portion of the RES being collected by APS in base rates rather than through the RES adjustor.

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 June 12, 2018, the ACC approved the 2018 RES Implementation Plan including a waiver of the distributed energy requirements for the 2018 implementation year.

On June 29, 2018, APS filed its 2019 RES Implementation Plan and proposed a budget of approximately $89.9 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the residential distributed energy requirement for 2019 contained in the RES rules. On October 29, 2019, the ACC approved the 2019 RES Implementation Plan including a waiver of the residential distributed energy requirements for the 2019 implementation year.

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 residential distributed energy requirement for 2020 contained in the RES rules. The ACC has not yet ruled on the 2020 RES Implementation Plan.

On July 2, 2019, ACC Staff issued draft rules, which propose a RES goal of 45% of retail energy served be renewables by 2035 and a goal of 20% of retail sales during peak demand to be from clean energy resources by 2035. The draft rules would also require a certain amount of the RES goal to be derived from distributed renewable storage, for which utilities would be required to offer performance-based incentives. Nuclear energy would be considered a clean resource under the draft rules. See "Energy Modernization Plan" below for more information.

On January 8, 2020, an ACC commissioner proposed replacing the current RES standard with a new standard ("KREST II"). KREST II sets a RES goal of 50% of retail energy to be served by renewables by 2028, 100% zero carbon resources by 2045, and a 35% energy efficiency resource standard by 2030 with a 10% demand response carve out. APS cannot predict the outcome of this matter.

Demand Side Management Adjustor Charge. The ACC EES requires APS to submit a Demand Side Management Implementation Plan ("DSM Plan") annually for review by and approval of the ACC. Verified energy savings from APS's resource savings projects can be counted toward compliance with the Electric Energy Efficiency Standards; however, APS is not allowed to count savings from systems savings projects toward determination of the achievement of performance incentives, nor may APS include savings from these system savings projects in the calculation of its LFCR mechanism (see below for discussion of the LFCR).

On September 1, 2017, APS filed its 2018 DSM Plan, which proposes modifications to the demand side management portfolio to better meet system and customer needs by focusing on peak demand reductions, storage, load shifting and demand response programs in addition to traditional energy savings measures. The 2018 DSM Plan seeks a requested budget of $52.6 million and requests a waiver of the Electric Energy Efficiency Standard for 2018. On November 14, 2017, APS filed an amended 2018 DSM Plan, which revised the allocations between budget items to address customer participation levels, but kept the overall budget at $52.6 million. The ACC has not yet ruled on the APS 2018 amended DSM Plan.

On December 31, 2018, APS filed its 2019 DSM Plan, which requests a budget of $34.1 million and continues APS's focus on DSM strategies such as peak demand reduction, load shifting, storage and electrification strategies. The ACC has not yet ruled on the APS 2019 DSM Plan.

On December 31, 2019, APS filed its 2020 DSM Plan, which requests a budget of $51.9 million and continues APS's focus on DSM strategies such as peak demand reduction, load shifting, storage and electrification strategies. The 2020 DSM Plan addresses all components of the 2018 and 2019 DSM plans, which enables the ACC to review the 2020 DSM Plan only. The ACC has not yet ruled on the APS 2020 DSM 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 2019 and 2018 (dollars in thousands):

	Twelve Months Ended December 31,	
	2019	**2018**
Beginning balance	$ 37,164	$ 75,637
Deferred fuel and purchased power costs — current period	82,481	78,277
Amounts charged to customers	(49,508)	(116,750)
Ending balance	$ 70,137	$ 37,164

The PSA rate for the PSA year beginning February 1, 2018 is $0.004555 per kWh, consisting of a Forward Component of $0.002009 per kWh and a Historical Component of $0.002546 per kWh. This represented a $0.004 per kWh increase over the August 19, 2017 PSA, the maximum permitted under the Plan of Administration for the PSA. This left $16.4 million of 2017 fuel and purchased power costs above this annual cap. These costs rolled over into the following year and were reflected in the 2019 reset of the PSA.

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The PSA rate for the PSA year beginning February 1, 2019 is $0.001658 per kWh, consisting of a Forward Component of $0.000536 per kWh and a Historical Component of $0.001122 per kWh. This represented a $0.002897 per kWh decrease compared to 2018.

On November 27, 2019, APS filed its PSA rate for the PSA year beginning February 1, 2020. That rate was $(0.000456) per kWh and 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 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. This application is pending with the ACC. APS cannot predict the outcome of this matter.

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 1st for qualified environmental improvements made during the prior calendar 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 - 14 million per year). APS's February 1, 2020 application requested an increase in the charge to $8.75 million, or $2.0 million over the charge in effect for the 2019-2020 rate effective year.

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

The formula rate is updated each year effective June 1 on the basis of APS's actual cost of service, as disclosed in APS's FERC Form 1 report for the previous fiscal year. Items to be updated include actual capital expenditures made as compared with previous projections, transmission revenue credits and other items. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected. 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 at 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.

On March 7, 2018, APS made a filing to make modifications to its annual transmission formula to provide transmission customers the benefit of the reduced federal corporate income tax rate resulting from the Tax Act beginning in its 2018 annual transmission formula rate update filing. These modifications were approved by FERC on May 22, 2018 and reduced APS's transmission rates compared to the rate that would have gone into effect absent these changes.

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Effective June 1, 2018, APS's annual wholesale transmission rates for all users of its transmission system decreased by approximately $22.7 million for the twelve-month period beginning June 1, 2018 in accordance with the FERC approved formula. An adjustment to APS’s retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2018.

Effective June 1, 2019, APS's annual wholesale transmission rates for all users of its transmission system increased by approximately $4.9 million for the twelve-month period beginning June 1, 2019 in accordance with the FERC-approved formula. An adjustment to APS’s retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2019.

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 first established in the 2012 Settlement Agreement and amount to approximately 3.1 cents per residential kWh lost and 2.3 cents per non-residential kWh lost. These amounts were revised in the 2017 Settlement Agreement to 2.5 cents for both lost residential and non-residential kWh. 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 15, 2018, APS filed its 2018 annual LFCR adjustment, requesting that effective May 1, 2018, the LFCR be adjusted to $60.7 million. On February 6, 2019, the ACC approved the 2018 annual LFCR adjustment to become effective March 1, 2019. On February 15, 2019, APS filed its 2019 annual LFCR adjustment, requesting that effective May 1, 2019, the annual LFCR recovery amount be reduced to $36.2 million (a $24.5 million decrease from previous levels). On July 10, 2019, the ACC approved APS’s 2019 LFCR adjustment as filed, effective with the next billing cycle of July 2019. 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). APS cannot predict the outcome or timing of the ACC’s consideration of this filing. Because the LFCR mechanism has a balancing account that trues up any under or over recoveries, the delay in implementation does not have an adverse effect on APS.

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 January 8, 2018, APS filed an application with the ACC that addressed the change in the marginal federal tax rate from 35% to 21% resulting from the Tax Act and reduced rates by $119.1 million annually through an equal cents per kWh credit ("TEAM Phase I"). On February 22, 2018, the ACC approved the reduction of rates through an equal cents per kWh credit. The rate reduction was effective for the first billing cycle in March 2018.

The impact of the TEAM Phase I, over time, is expected to be earnings neutral. However, on a quarterly basis, there is a difference between the timing and amount of the income tax benefit and the reduction in revenues refunded through the TEAM Phase I related to the lower federal income tax rate. The amount of the benefit of the lower federal income tax rate is based on quarterly pre-tax results, while the reduction in revenues refunded through the TEAM Phase I is based on a per kWh sales credit which follows our seasonal kWh sales pattern and is not impacted by earnings of the Company.

On August 13, 2018, APS filed a second request with the ACC that addressed the return of an additional $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 final billing cycle of March 2020. Both the timing of the reduction in revenues refunded through TEAM Phase II and the offsetting income tax benefit are 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 will provide an additional benefit of $39.5 million to customers through December 31, 2020. It is currently anticipated that benefits related to the amortization of depreciation related excess deferred taxes for periods beginning after December 31, 2020 will be fully incorporated into the 2019 rate case filing.

Net Metering

In 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of DG to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing was held in April 2016. On October 7, 2016, the Administrative Law Judge issued a recommendation in the docket concerning the value and cost of DG solar installations. On December 20, 2016, the ACC completed its open meeting to consider the recommended opinion and order by the Administrative Law Judge. After making several amendments, the ACC approved the recommended decision by a 4-1 vote. As a result of the ACC’s action, effective with APS’s 2017 Rate Case Decision, the net metering tariff that governs payments for energy exported to the grid from residential rooftop solar systems was replaced by a more formula-driven approach that utilizes inputs from historical wholesale solar power until an avoided cost methodology is developed by the ACC.

As amended, the decision provides that payments by utilities for energy exported to the grid from DG solar facilities will be determined using a RCP methodology, a method that is based on the most recent five-year rolling average price that APS pays for utility-scale solar projects, while a forecasted avoided cost methodology is being developed. 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. Once the avoided cost methodology is developed, the ACC will determine in APS's subsequent rate cases which method (or a combination of methods) is appropriate to determine the actual price to be paid by APS for exported distributed energy.

In addition, the ACC made the following determinations:

- Customers who have interconnected a DG system or submitted an application for interconnection for DG systems prior to September 1, 2017, based on APS's 2017 Rate Case Decision, will be grandfathered for a period of 20 years from the date the customer's interconnection application was accepted by the utility;

- Customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and

- Once an export price is set for APS, 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. A first-year export energy price of 12.9 cents per kWh was included in the 2017 Settlement Agreement and became effective on September 1, 2017.

In accordance with the 2017 Rate Case Decision, APS filed its request for a second-year export energy price of 11.6 cents per kWh on May 1, 2018. This price reflected the 10% annual reduction discussed above. The new rate rider became effective on October 1, 2018. APS filed its request for a third-year 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.

On January 23, 2017, The Alliance for Solar Choice ("TASC") sought rehearing of the ACC's decision regarding the value and cost of DG. TASC asserted that the ACC improperly ignored the Administrative Procedure Act, failed to give adequate notice regarding the scope of the proceedings, and relied on information that was not submitted as evidence, among other alleged defects. TASC filed a Notice of Appeal in the Arizona Court of Appeals and filed a Complaint and Statutory Appeal in the Maricopa County Superior Court on March 10, 2017. As part of the 2017 Settlement Agreement described above, TASC agreed to withdraw these appeals when the ACC decision implementing the 2017 Settlement Agreement is no longer subject to appellate review.

See "2016 Retail Rate Case Filing with the Arizona Corporation Commission" 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 Arizona Corporation Commissioner Robert Burns

On August 25, 2016, Commissioner 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.

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On September 9, 2016, APS filed with the ACC a motion to quash the subpoenas or, alternatively to stay APS's obligations to comply with the subpoenas and decline to decide APS's motion pending court proceedings. Contemporaneously with the filing of this motion, APS and Pinnacle West filed a complaint for special action and declaratory judgment in the Superior Court of Arizona for Maricopa County, seeking a declaratory judgment that Commissioner Burns’ subpoenas are contrary to law. On September 15, 2016, APS produced all non-confidential and responsive documents and offered to produce any remaining responsive documents that are confidential after an appropriate confidentiality agreement is signed.

On February 7, 2017, Commissioner Burns opened a new ACC docket and indicated that its purpose is to study and rectify problems with transparency and disclosure regarding financial contributions from regulated monopolies or other stakeholders who may appear before the ACC that may directly or indirectly benefit an ACC Commissioner, a candidate for ACC Commissioner, or key ACC Staff. As part of this docket, Commissioner Burns set March 24, 2017 as a deadline for the production of all information previously requested through the subpoenas. Neither APS nor Pinnacle West produced the information requested and instead objected to the subpoena. On March 10, 2017, Commissioner Burns filed suit against APS and Pinnacle West in the Superior Court of Arizona for Maricopa County in an effort to enforce his subpoenas. On March 30, 2017, APS filed a motion to dismiss Commissioner Burns' suit against APS and Pinnacle West. In response to the motion to dismiss, the court stayed the suit and ordered Commissioner Burns to file a motion to compel the production of the information sought by the subpoenas with the ACC. On June 20, 2017, the ACC denied the motion to compel.

On August 4, 2017, Commissioner Burns amended his complaint to add all of the ACC Commissioners and the ACC itself as defendants. All defendants moved to dismiss the amended complaint. On February 15, 2018, the Superior Court dismissed Commissioner Burns’ amended complaint. On March 6, 2018, Commissioner Burns filed an objection to the proposed final order from the Superior Court and a motion to further amend his complaint. The Superior Court permitted Commissioner Burns to amend his complaint to add a claim regarding his attempted investigation into whether his fellow commissioners should have been disqualified from voting on APS’s 2017 rate case. Commissioner Burns filed his second amended complaint, and all defendants filed responses opposing the second amended complaint and requested that it be dismissed. Oral argument occurred in November 2018 regarding the motion to dismiss. On December 18, 2018, the trial court granted the defendants’ motions to dismiss and entered final judgment on January 18, 2019. On February 13, 2019, Commissioner Burns filed a notice of appeal. On July 12, 2019, Commissioner Burns filed his opening brief in the Arizona Court of Appeals. APS filed its answering brief on October 21, 2019. The Arizona Court of Appeals granted the request for oral argument but no date has been set. APS and Pinnacle West cannot predict the outcome of this matter.

Information Requests from Arizona Corporation Commissioners

On January 14, 2019, ACC Commissioner Kennedy opened a docket to investigate campaign expenditures and political participation of APS and Pinnacle West. In addition, on February 27, 2019, ACC Commissioners Burns and Dunn opened a new docket and requested documents from APS and Pinnacle West related to ACC elections and charitable contributions related to the ACC. On March 1, 2019, ACC Commissioner Kennedy issued a subpoena to APS seeking several categories of information for both Pinnacle West and APS including political contributions, lobbying expenditures, marketing and advertising expenditures, and contributions made to 501(c)(3) and 501(c)(4) entities, for the years 2013-2018. Pinnacle West and APS voluntarily responded to both sets of requests on March 29, 2019. APS also received and responded to various follow-on requests from ACC Commissioners on these matters. Pinnacle West and APS cannot predict the outcome of these matters. The Company's CEO, Mr. Guldner, appeared at the ACC's January 14, 2020 Open Meeting regarding ACC Commissioners' questions about political spending. Mr. Guldner committed to the ACC that during his tenure, Pinnacle West and APS, and any of their affiliated companies, will not participate in ACC campaign elections through financial contributions or in-kind contributions.

2018 Renewable Energy Ballot Initiative

On February 20, 2018, a renewable energy advocacy organization filed with the Arizona Secretary of State a ballot initiative for an Arizona constitutional amendment requiring Arizona public service corporations to provide at least 50% of their annual retail sales of electricity from renewable sources by 2030. For purposes of the proposed amendment, eligible renewable sources would not include nuclear generating facilities. The initiative was placed on the November 2018 Arizona elections ballot. On November 6, 2018, the initiative failed to receive adequate voter support and was defeated.

Energy Modernization Plan

On January 30, 2018, former ACC Commissioner Tobin proposed the Energy Modernization Plan, which consisted of a series of energy policies tied to clean energy sources such as energy storage, biomass, energy efficiency, electric vehicles, and expanded energy planning through the integrated resource plan ("IRP") process. In August 2018, the ACC directed ACC Staff to open a new rulemaking docket which will address a wide range of energy issues, including the Energy Modernization Plan proposals. The rulemaking will consider possible modifications to existing ACC rules, such as the RES, Electric and Gas Energy Efficiency Standards, Net Metering, Resource Planning, and the Biennial Transmission Assessment, as well as the development of new rules regarding forest bioenergy, electric vehicles, interconnection of distributed generation, baseload security, blockchain technology and other technological developments, retail competition, and other energy-related topics. On April 25, 2019, the ACC Staff issued a set of draft rules in regards to the Energy Modernization Plan and workshops were held on April 29, 2019 regarding these draft rules. On July 2, 2019, the ACC Staff issued a revised set of draft rules, which propose a RES goal of 45% of retail energy served be renewable by 2035 and a goal of 20% of retail sales during peak demand to be from clean energy resources by 2035. The draft rules also require a certain amount of the RES goal to be derived from distributed renewable storage, for which utilities would be required to offer performance-based incentives. Nuclear energy would be considered a clean resource under the draft rules. The ACC held various stakeholder meetings and workshops on ACC Staff’s draft energy rules in July through September 2019 and have scheduled a workshop to be held on March 10 - 11, 2020. On February 19, 2020, the ACC Staff issued a revised proposed set of draft rules that will be discussed at the workshop. APS cannot predict the outcome of this matter.

Integrated Resource Planning

ACC rules require utilities to develop fifteen-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. In March of 2018, the ACC reviewed the 2017 IRPs of its jurisdictional utilities and voted to not acknowledge any of the plans. APS does not believe that this lack of acknowledgment will have a material impact on our financial position, results of operations or cash flows. 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 IRP's from April 1, 2020 to June 26, 2020.

Public Utility Regulatory Policies Act

In August 2016, APS filed an application requesting that all of its contracts with qualifying facilities over 100 kW be set at a presumptive maximum 2-year term. A qualifying facility is an eligible energy-producing facility as defined by FERC regulations within a host electric utility's service territory that has a right to sell to the host utility. Host utilities are required to purchase power from qualifying facilities at an avoided cost as determined by the utility subject to state commission oversight. A hearing was held in August 2019 and briefing on this matter was completed in October 2019 regarding APS's application. On December 17, 2019, the ACC denied the application and mandated a minimum contract length of 18 years for qualifying facilities over 100 kW and the rate paid to the qualifying facilities will be based on the long-term avoided cost.

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 from June 1 through October 15. During the moratorium on disconnections, 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. The emergency rule changes will be effective for 180 days and may be renewed for one additional 180 day period. During that time, 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 electric 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 issued draft amendments to the customer service disconnections rules. Stakeholders submitted initial comments to the draft amendments on September 23, 2019. ACC stakeholder meetings were held in September 2019, October 2019 and January 2020 regarding the customer service disconnections rules. The disconnection moratorium resulted in a negative impact to our 2019 operating results of approximately $10 million pre-tax. APS is further assessing the impact to its financial statements beyond 2019, which will be affected by the results of final rulemaking related to disconnections.

Retail Electric Competition Rules

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. An ACC special open meeting workshop was held on December 3, 2018. No substantive action was taken, but interested parties were asked to submit written comments and respond to a list of questions from ACC Staff. 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. Interested parties filed comments to the ACC Staff report, and a stakeholder meeting and workshop to discuss the retail electric competition rules was held on July 30, 2019. ACC Commissioners submitted additional questions regarding this matter. 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. The ACC has scheduled a workshop for February 25-26, 2020 for further consideration and discussion of the retail electric competition rules. APS cannot predict whether these efforts will result in any changes and, if changes to the rules results, what impact these rules would have on APS.

Rate Plan Comparison Tool

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 the Company'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 that would result in the lowest bills 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. APS is providing 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 and a $25 payment for any inconvenience that the customer may have experienced. The refunds and payment for inconvenience being provided is not expected to have a material impact on APS's financial statements. The ACC is currently investigating this matter. APS received a civil investigative demand from the Office of the Arizona Attorney General, Civil Litigation Division, Consumer Protection & Advocacy Section that seeks information pertaining to the rate plan comparison tool offered to APS customers. APS is fully cooperating with the Attorney General's Office in this matter. APS cannot predict the outcome of these matters.

Four Corners

SCE-Related Matters. As part of APS's acquisition of SCE's interest in Units 4 and 5, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provide transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS established a regulatory asset of $12 million in 2015 in connection with the payment required under the terms of the Transmission Agreement. On July 1, 2016, FERC issued an order denying APS's request to recover the regulatory asset through its FERC-jurisdictional rates. APS and SCE completed the termination of the Transmission Agreement on July 6, 2016. APS made the required payment to SCE and wrote off the $12 million regulatory asset and charged operating revenues to reflect the effects of this order in the second quarter of 2016. On July 29, 2016, APS filed a request for rehearing with FERC. In its order denying recovery, FERC also referred to its enforcement division a question of whether the agreement between APS and SCE relating to the settlement of obligations under the Transmission Agreement was a jurisdictional contract that should have been filed with FERC. On October 5, 2017, FERC issued an order denying APS's request for rehearing. FERC also upheld its prior determination that the agreement relating to the settlement was a jurisdictional contract and should have been filed with FERC. APS filed an appeal of FERC's July 1, 2016 and October 5, 2017 orders with the United States Court of Appeals for the Ninth Circuit on December 4, 2017. On June 14, 2019, the United States Court of Appeals for the Ninth Circuit issued an unpublished memorandum order denying APS's petition for review of FERC's orders that denied APS's request to recover the regulatory asset through its FERC-jurisdictional rates and granting APS's petition for review of FERC's orders finding the agreement to be a jurisdictional contract. The United States Court of Appeals for the Ninth Circuit vacated FERC's determination that the agreement was required to be filed with FERC and remanded the issue to FERC for additional proceedings. On December 18, 2019, APS submitted an offer of settlement to FERC to resolve all outstanding issues related to this matter. The offer of settlement provided that APS would not recover in rates any portion of any payment it made to SCE in connection with the expiration of the Transmission Agreement and FERC would close certain dockets related to this matter. On February 5, 2020, FERC issued an order accepting APS's offer of settlement and resolved this matter.

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. Consistent with the 2017 Rate Case Decision, the request was narrow in scope and addressed only costs associated with this specific environmental compliance equipment. 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. Exceptions to the Recommended Opinion and Order were filed by the parties and intervenors on December 7, 2018. The ACC has not issued a decision on this matter. APS included the costs for the SCR project in the retail rate base in its 2019 retail rate case filing with the ACC. APS cannot predict the outcome or timing of the decision on this matter. APS may be required to record a charge to its results of operations if the ACC issues an unfavorable decision (see SCR deferral in the Regulatory Assets and Liabilities table below).

Cholla

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

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 ($73 million as of December 31, 2019), 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. The 2017 Settlement Agreement also shortened the depreciation lives of Cholla Units 1 and 3 to 2025.

On March 20, 2019, APS announced that it began evaluating the feasibility and cost of converting a unit at Cholla to burn biomass. Biomass is a fuel comprised of forest trimmings, and a converted unit at Cholla could assist in forest thinning, responsible forest management, an improved watershed, and a reduced wildfire risk. APS’s ability to operate a biomass power plant would depend on third-parties procuring forest biomass for fuel. APS reported the results of its evaluation on May 9, 2019 to the ACC. On July 10, 2019, the ACC voted to not require APS to file a request for proposal to convert the unit at Cholla to burn biomass.

Navajo Plant

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 that allows 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 ($82 million as of December 31, 2019) plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and may be material. APS believes it will be allowed recovery of the net book value, in addition to a return on its investment. 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. If the ACC does not allow full recovery of the remaining net book value of this interest, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted.

Regulatory Assets and Liabilities

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

		December 31, 2019		December 31, 2018	
	Amortization Through	Current	Non-Current	Current	Non-Current
Pension	(a)	$ —	$ 660,223	$ —	$ 733,351
Retired power plant costs	2033	28,182	142,503	28,182	167,164
Income taxes - AFUDC equity	2049	6,800	154,974	6,457	151,467
Deferred fuel and purchased power (b) (c)	2020	70,137	—	37,164	—
Deferred fuel and purchased power — mark-to-market (Note 17)	2024	36,887	33,185	31,728	23,768
Deferred property taxes	2027	8,569	58,196	8,569	66,356
SCR deferral	N/A	—	52,644	—	23,276
Four Corners cost deferral	2024	8,077	32,152	8,077	40,228
Ocotillo deferral	N/A	—	38,144	—	—
Deferred compensation	2036	—	36,464	—	36,523
Income taxes — investment tax credit basis adjustment	2048	1,098	24,981	1,079	25,522
Lost fixed cost recovery (b)	2020	26,067	—	32,435	—
Palo Verde VIEs (Note 19)	2046	—	20,635	—	20,015
Coal reclamation	2026	1,546	17,688	1,546	15,607
Loss on reacquired debt	2038	1,637	12,031	1,637	13,668
Mead-Phoenix transmission line - contributions in aid of construction	2050	332	9,712	332	10,044
TCA balancing account (b)	2021	6,324	2,885	3,860	772
Tax expense of Medicare subsidy	2024	1,235	4,940	1,235	6,176
AG-1 deferral	2022	2,787	2,716	2,654	5,819
Tax expense adjustor mechanism (b)	2020	1,612	—	—	—
Other	Various	1,917	—	1,947	3,185
Total regulatory assets (d)		$ 203,207	$ 1,304,073	$ 166,902	$ 1,342,941

(a) This asset represents the future recovery of pension benefit obligations 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. See Note 8 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."

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

		December 31, 2019		December 31, 2018	
	Amortization Through	Current	Non-Current	Current	Non-Current
Excess deferred income taxes - ACC - Tax Cuts and Jobs Act (a)	2046	$ 59,918	$ 1,054,053	$ —	$ 1,272,709
Excess deferred income taxes - FERC - Tax Cuts and Jobs Act (a)	2058	6,302	237,357	6,302	243,691
Asset retirement obligations	2057	—	418,423	—	278,585
Removal costs	(c)	47,356	136,072	39,866	177,533
Other postretirement benefits	(d)	37,575	139,634	37,864	125,903
Income taxes - change in rates	2049	2,797	68,265	2,769	70,069
Spent nuclear fuel	2027	6,676	51,019	6,503	57,002
Four Corners coal reclamation	2038	1,059	51,704	1,858	17,871
Income taxes - deferred investment tax credit	2048	2,202	50,034	2,164	51,120
Renewable energy standard (b)	2021	39,287	10,300	44,966	20
Demand side management (b)	2021	15,024	24,146	14,604	4,123
Sundance maintenance	2031	5,698	11,319	1,278	17,228
Property tax deferral	N/A	—	7,046	—	2,611
Tax expense adjustor mechanism (b)	2020	7,018	—	3,237	—
Deferred gains on utility property	2022	2,423	4,163	4,423	6,581
FERC transmission true up	2021	1,045	2,004	—	—
Other	Various	532	2,296	42	930
Total regulatory liabilities		$ 234,912	$ 2,267,835	$ 165,876	$ 2,325,976

(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 8.

5. Income Taxes

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

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

The Tax Act reduced the corporate tax rate to 21% effective January 1, 2018. As a result of this rate reduction, the Company recognized a $1.14 billion reduction in its net deferred income tax liabilities as of December 31, 2017. In accordance with accounting for regulated companies, the effect of this rate reduction was substantially offset by a net regulatory liability.

Federal income tax laws require the amortization of a majority of the balance over the remaining regulatory life of the related property. As a result of the modifications made to the annual transmission formula rate during the second quarter of 2018, the Company began amortization of FERC jurisdictional net excess deferred tax liabilities in 2018. On March 13, 2019, the ACC approved the Company's proposal to amortize non-depreciation related net excess deferred tax liabilities subject to its jurisdiction over a twelve-month period. As a result, the Company began amortization in March 2019. As of December 31, 2019, the Company has recorded $57 million of income tax benefit related to the amortization of these non-depreciation related net excess deferred tax liabilities. On October 29, 2019, the ACC approved the Company's proposal to amortize depreciation related net excess deferred tax liabilities subject to its jurisdiction over a 28.5-year period with amortization to retroactively begin as of January 1, 2018. As a result, in the fourth quarter of 2019, the Company has recorded $62 million of income tax benefit related to amortization of these depreciation related liabilities. See Note 4 for more details.

In August 2018, U.S. Treasury proposed regulations that clarified bonus depreciation transition rules under the Tax Act for regulated public utility property placed in service after September 27, 2017 and before January 1, 2018. However, these proposed regulations were ambiguous with respect to regulated public utility property placed in service on or after January 1, 2018. In September 2019, U.S. Treasury issued final regulations, which replaced the August 2018 proposed regulations. These final regulations did not materially impact any tax position taken by the Company for property placed in service after September 27, 2017 and before January 1, 2018.

Along with the September 2019 final regulations, U.S. Treasury also issued new proposed regulations which clarify bonus depreciation transition rules under the Tax Act for property placed in service by regulated public utilities after December 31, 2017. The proposed regulations provide that certain regulated public utility property which was under construction prior to September 28, 2017 and placed in service between January 1, 2018 and December 31, 2020 would continue to be eligible for bonus depreciation under the rules and bonus depreciation phase-downs in effect prior to enactment of the Tax Act. During the third quarter of 2019, as a result of the clarification provided by these proposed regulations, the Company recorded additional deferred tax liabilities of approximately $56 million related to bonus depreciation benefits claimed on the Company's 2018 tax return.

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 statement 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 19 for additional details related to the Palo Verde sale leaseback VIEs.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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		
	2019	2018	2017	2019	2018	2017
Total unrecognized tax benefits, January 1	$ 40,731	$ 41,966	$ 36,075	$ 40,731	$ 41,966	$ 36,075
Additions for tax positions of the current year	3,373	3,436	2,937	3,373	3,436	2,937
Additions for tax positions of prior years	1,843	2,696	4,783	1,843	2,696	4,783
Reductions for tax positions of prior years for:						
Changes in judgment	(2,078)	(1,764)	(1,829)	(2,078)	(1,764)	(1,829)
Settlements with taxing authorities	—	—	—	—	—	—
Lapses of applicable statute of limitations	(434)	(5,603)	—	(434)	(5,603)	—
Total unrecognized tax benefits, December 31	$ 43,435	$ 40,731	$ 41,966	$ 43,435	$ 40,731	$ 41,966

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		
	2019	2018	2017	2019	2018	2017
Tax positions, that if recognized, would decrease our effective tax rate	$ 22,813	$ 19,504	$ 16,373	$ 22,813	$ 19,504	$ 16,373

As of the balance sheet date, the tax year ended December 31, 2016 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 2015.

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		
	2019	2018	2017	2019	2018	2017
Unrecognized tax benefit interest expense/(benefit) recognized	$ 459	$ (780)	$ 577	$ 459	$ (780)	$ 577

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		
	2019	2018	2017	2019	2018	2017
Unrecognized tax benefit interest accrued	$ 1,589	$ 1,130	$ 1,910	$ 1,589	$ 1,130	$ 1,910

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Additionally, as of December 31, 2019, 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,		
	2019	2018	2017	2019	2018	2017
Current:						
Federal	$ (13,551)	$ 18,375	$ 11,624	$ (54,697)	$ 88,180	$ 21,512
State	3,195	3,342	3,052	695	1,877	2,778
Total current	(10,356)	21,717	14,676	(54,002)	90,057	24,290
Deferred:						
Federal	(14,982)	94,721	223,729	29,321	32,436	221,078
State	9,565	17,464	19,867	15,109	22,321	23,800
Total deferred	(5,417)	112,185	243,596	44,430	54,757	244,878
Income tax expense/(benefit)	$ (15,773)	$ 133,902	$ 258,272	$ (9,572)	$ 144,814	$ 269,168

The following chart compares pretax income at the statutory federal income tax rate of 21% in 2019 and 2018 and 35% in 2017 to income tax expense (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	Year Ended December 31,			Year Ended December 31,		
	2019	2018	2017	2019	2018	2017
Federal income tax expense at statutory rate	$ 113,828	$ 139,533	$ 268,177	$ 120,790	$ 154,260	$ 277,540
Increases (reductions) in tax expense resulting from:						
State income tax net of federal income tax benefit	18,599	23,115	21,380	19,267	24,531	22,329
State income tax credits net of federal income tax benefit	(8,519)	(6,704)	(6,483)	(6,781)	(5,440)	(5,053)
Nondeductible expenditures associated with ballot initiative	—	7,879	—	—	—	—
Stock compensation	(2,252)	(1,804)	(6,659)	(1,054)	(780)	(3,489)
Excess deferred income taxes - Tax Cuts and Jobs Act	(124,082)	(6,725)	9,348	(124,082)	(4,715)	9,431
Allowance for equity funds used during construction (see Note 1)	(2,476)	(7,231)	(12,937)	(2,476)	(7,231)	(12,937)
Palo Verde VIE noncontrolling interest (see Note 19)	(4,094)	(4,094)	(6,823)	(4,094)	(4,094)	(6,823)
Investment tax credit amortization	(6,851)	(6,742)	(6,715)	(6,851)	(6,742)	(6,715)
Other	74	(3,325)	(1,016)	(4,291)	(4,975)	(5,115)
Income tax expense/(benefit)	$ (15,773)	$ 133,902	$ 258,272	$ (9,572)	$ 144,814	$ 269,168

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	Pinnacle West Consolidated		APS Consolidated	
	December 31,		December 31,	
	2019	2018	2019	2018
DEFERRED TAX ASSETS				
Risk management activities	$ 17,552	$ 15,785	$ 17,552	$ 15,785
Regulatory liabilities:				
Excess deferred income taxes - Tax Cuts and Jobs Act	335,877	376,869	335,877	376,869
Asset retirement obligation and removal costs	143,011	117,201	143,011	117,201
Unamortized investment tax credits	52,236	53,284	52,236	53,284
Other postretirement benefits	43,841	40,532	43,841	40,532
Other	52,382	40,380	52,382	40,380
Pension liabilities	73,210	112,019	67,976	107,009
Coal reclamation liabilities	40,837	47,508	40,837	47,508
Renewable energy incentives	28,066	30,779	28,066	30,779
Credit and loss carryforwards	54,795	1,755	10,992	—
Other	63,102	58,820	70,948	59,919
Total deferred tax assets	904,909	894,932	863,718	889,266
DEFERRED TAX LIABILITIES				
Plant-related	(2,448,458)	(2,277,724)	(2,448,458)	(2,277,724)
Risk management activities	(27)	(237)	(27)	(237)
Other postretirement assets and other special use funds	(66,399)	(57,697)	(65,965)	(57,274)
Regulatory assets:				
Allowance for equity funds used during construction	(40,023)	(39,086)	(40,023)	(39,086)
Deferred fuel and purchased power	(35,162)	(23,086)	(35,162)	(23,086)
Pension benefits	(163,339)	(181,504)	(163,339)	(181,504)
Retired power plant costs (see Note 4)	(42,228)	(48,348)	(42,228)	(48,348)
Other	(82,722)	(72,096)	(82,722)	(72,096)
Other	(18,890)	(2,575)	(18,890)	(2,575)
Total deferred tax liabilities	(2,897,248)	(2,702,353)	(2,896,814)	(2,701,930)
Deferred income taxes — net	$ (1,992,339)	$ (1,807,421)	$ (2,033,096)	$ (1,812,664)

As of December 31, 2019, the deferred tax assets for credit and loss carryforwards relate to federal general business credits of approximately $62 million, which first begin to expire in 2036, state credit carryforwards net of federal benefit of $23 million, which first begin to expire in 2023, and other federal carryforwards of $9 million. The credit and loss carryforwards amount above has been reduced by $39 million of unrecognized tax benefits.

6. Lines of Credit and Short-Term Borrowings

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The table below presents the consolidated credit facilities and the amounts available and outstanding as of December 31, 2019 and 2018 (dollars in thousands):

	December 31, 2019			December 31, 2018		
	Pinnacle West	APS	Total	Pinnacle West	APS	Total
Commitments under Credit Facilities	$ 200,000	$ 1,000,000	$ 1,200,000	$ 350,000	$ 1,000,000	$ 1,350,000
Outstanding Commercial Paper and Revolving Credit Facility Borrowings	(76,675)	—	(76,675)	(76,400)	—	(76,400)
Amount of Credit Facilities Available	$ 123,325	$ 1,000,000	$ 1,123,325	$ 273,600	$ 1,000,000	$ 1,273,600
Weighted-Average Commitment Fees	0.125%	0.100%		0.125%	0.100%	

Pinnacle West

On May 9, 2019, Pinnacle West entered into a $50 million term loan agreement that matures May 7, 2020. Pinnacle West used the proceeds to refinance indebtedness under and terminate a prior $150 million revolving credit facility. Borrowings under the agreement bear interest at London Inter-bank Offered Rate ("LIBOR") plus 0.55% per annum. At December 31, 2019, Pinnacle West had $38 million in outstanding borrowings under the agreement.

At December 31, 2019, Pinnacle West had a $200 million revolving credit facility that matures in July 2023. 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. The facility is available to support Pinnacle West's $200 million commercial paper program, for bank borrowings or for issuances of letters of credits. At December 31, 2019, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and $77 million of commercial paper borrowings.

APS

At December 31, 2019, APS had two revolving credit facilities totaling $1 billion, including a $500 million credit facility that matures in June 2022 and a $500 million facility that matures in July 2023. 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. These facilities are available to support APS's $500 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2019, APS had no commercial paper outstanding and no outstanding borrowings or letters of credit under its revolving credit facilities. See "Financial Assurances" in Note 11 for a discussion of APS's other outstanding letters of credit.

Debt Provisions

On November 27, 2018, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved APS's short-term debt authorization equal to a sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power). See Note 7 for additional long-term debt provisions.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

7. Long-Term Debt and Liquidity Matters

All of Pinnacle West's and APS's debt is unsecured. The following table presents the components of long-term debt on the Consolidated Balance Sheets outstanding at December 31, 2019 and 2018 (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31, 2019	December 31, 2018
APS				
Pollution control bonds:				
Variable	2029	(b)	$ 35,975	$ 35,975
Fixed	2024	4.70%	115,150	115,150
Total pollution control bonds			151,125	151,125
Senior unsecured notes	2020-2049	2.20%-6.88%	4,875,000	4,575,000
Term loans		(c)	200,000	—
Unamortized discount			(12,434)	(12,638)
Unamortized premium			7,423	7,736
Unamortized debt issuance cost			(37,981)	(31,787)
Total APS long-term debt			5,183,133	4,689,436
Less current maturities			350,000	500,000
Total APS long-term debt less current maturities			4,833,133	4,189,436
Pinnacle West				
Senior unsecured notes	2020	2.25%	300,000	300,000
Term loan	2020	(d)	150,000	150,000
Unamortized discount			(57)	(121)
Unamortized debt issuance cost			(518)	(1,083)
Total Pinnacle West long-term debt			449,425	448,796
Less current maturities			450,000	—
Total Pinnacle West long-term debt less current maturities			(575)	448,796
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$ 4,832,558	$ 4,638,232

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturities.
(b) The weighted-average rate for the variable rate pollution control bonds was 1.54% at December 31, 2019 and 1.76% at December 31, 2018.
(c) The weighted-average interest rate was 2.12% at December 31, 2019.
(d) The weighted-average interest rate was 2.20% at December 31, 2019 and 3.02% at December 31, 2018.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

Year	Consolidated Pinnacle West	Consolidated APS
2020	$ 800,000	$ 350,000
2021	—	—
2022	—	—
2023	—	—
2024	365,150	365,150
Thereafter	4,510,975	4,510,975
Total	$ 5,676,125	$ 5,226,125

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, 2019		As of December 31, 2018	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 449,425	$ 450,822	$ 448,796	$ 443,955
APS	5,183,133	5,743,570	4,689,436	4,789,608
Total	$ 5,632,558	$ 6,194,392	$ 5,138,232	$ 5,233,563

Credit Facilities and Debt Issuances

APS

On February 26, 2019, APS entered into a $200 million term loan agreement that matures August 26, 2020. APS used the proceeds to repay existing indebtedness. Borrowings under the agreement bear interest at LIBOR plus 0.50% per annum.

On February 28, 2019, APS issued $300 million of 4.25% unsecured senior notes that mature on March 1, 2049. The net proceeds from the sale, together with funds made available from the term loan described above, were used to repay existing indebtedness.

On March 1, 2019, APS repaid at maturity $500 million aggregate principal amount of its 8.75% senior notes.

On August 19, 2019, APS issued $300 million of 2.6% unsecured senior notes that mature on August 15, 2029. The net proceeds from the sale were used to repay short-term indebtedness, consisting of commercial paper borrowings, and to replenish cash used to fund capital expenditures.

On November 20, 2019, APS issued $300 million of 3.5% unsecured senior notes that mature on December 1, 2049. The net proceeds from the sale were used to repay short-term indebtedness, consisting of commercial paper borrowings, to replenish cash used to fund capital expenditures, and to redeem, on December 30, 2019, $100 million of the $250 million aggregate principal amount of our 2.2% Notes due January 15, 2020.

On January 15, 2020, APS repaid at maturity the remaining $150 million of the $250 million aggregate principal amount of its 2.2% senior notes mentioned above.

See “Lines of Credit and Short-Term Borrowings” in Note 6 and “Financial Assurances” in Note 11 for discussion of APS’s separate outstanding letters of credit.

Debt Provisions

Pinnacle West’s and APS’s debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with this covenant. For both Pinnacle West and APS, this covenant requires that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At December 31, 2019, the ratio was approximately 52% for Pinnacle West and 47% 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 November 27, 2018, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved an increase in APS’s long-term debt authorization from $5.1 billion to $5.9 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs. See Note 6 for additional short-term debt provisions.

8. 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 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) for the employees of Pinnacle West and its subsidiaries. These plans provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plan, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions. We retain the right to change or eliminate these benefits.

Pinnacle West uses a December 31 measurement date each year for its pension and other postretirement benefit plans. The market-related value of our plan assets is their fair value at the measurement date. See Note 14 for further discussion of how fair values are determined. Due to subjective and complex judgments, which may be required in determining fair values, actual results could differ from the results estimated through the application of these methods.

A significant portion of the changes in the actuarial gains and losses of our pension and postretirement plans is attributable to APS and therefore is recoverable in rates. Accordingly, these changes are recorded as a regulatory asset or regulatory liability.

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			Other Benefits		
	2019	2018	2017	2019	2018	2017
Service cost-benefits earned during the period	$ 49,902	$ 56,669	$ 54,858	$ 18,369	$ 21,100	$ 17,119
Interest cost on benefit obligation	136,843	124,689	129,756	29,894	28,147	29,959
Expected return on plan assets	(171,884)	(182,853)	(174,271)	(38,412)	(42,082)	(53,401)
Amortization of:						
Prior service cost (credit)	—	—	81	(37,821)	(37,842)	(37,842)
Net actuarial loss	42,584	32,082	47,900	—	—	5,118
Net periodic benefit cost (benefit)	$ 57,445	$ 30,587	$ 58,324	$ (27,970)	$ (30,677)	$ (39,047)
Portion of cost charged to expense	$ 30,312	$ 10,120	$ 27,295	$ (19,859)	$ (21,426)	$ (18,274)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the plans' changes in the benefit obligations and funded status for the years 2019 and 2018 (dollars in thousands):

	Pension		Other Benefits	
	2019	2018	2019	2018
Change in Benefit Obligation				
Benefit obligation at January 1	$ 3,190,626	$ 3,394,186	$ 676,771	$ 753,393
Service cost	49,902	56,669	18,369	21,100
Interest cost	136,843	124,689	29,894	28,147
Benefit payments	(177,882)	(184,161)	(32,486)	(31,540)
Actuarial (gain) loss	413,625	(200,757)	54,376	(94,329)
Benefit obligation at December 31	3,613,114	3,190,626	746,924	676,771
Change in Plan Assets				
Fair value of plan assets at January 1	2,733,476	3,057,027	723,677	1,022,371
Actual return on plan assets	602,030	(201,078)	144,095	(40,354)
Employer contributions	150,000	50,000	—	—
Benefit payments	(167,155)	(172,473)	(30,278)	(72,453)
Transfer to active union medical account	—	—	—	(185,887)
Fair value of plan assets at December 31	3,318,351	2,733,476	837,494	723,677
Funded Status at December 31	$ (294,763)	$ (457,150)	$ 90,570	$ 46,906

The following table shows the projected benefit obligation and the accumulated benefit obligation for pension plans with an accumulated obligation in excess of plan assets as of December 31, 2019 and 2018 (dollars in thousands):

	2019	2018
Projected benefit obligation	$ 177,775	$ 3,190,626
Accumulated benefit obligation	169,091	3,038,774
Fair value of plan assets	—	2,733,476

The Pinnacle West Capital Corporation Retirement Plan is more than 100% funded on an accumulated benefits obligation basis at December 31, 2019, therefore the only pension plan with an accumulated benefits obligation in excess of plan assets in 2019 is a non-qualified supplemental excess benefit retirement plan.

The following table shows the amounts recognized on the Consolidated Balance Sheets as of December 31, 2019 and 2018 (dollars in thousands):

	Pension		Other Benefits	
	2019	2018	2019	2018
Noncurrent asset	$ —	$ —	$ 90,570	$ 46,906
Current liability	(14,578)	(13,980)	—	—
Noncurrent liability	(280,185)	(443,170)	—	—
Net amount recognized	$ (294,763)	$ (457,150)	$ 90,570	$ 46,906

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the details related to accumulated other comprehensive loss as of December 31, 2019 and 2018 (dollars in thousands):

	Pension		Other Benefits	
	2019	2018	2019	2018
Net actuarial loss	$ 735,186	$ 794,292	$ 12,238	$ 63,544
Prior service credit	—	—	(189,912)	(227,733)
APS’s portion recorded as a regulatory (asset) liability	(660,223)	(733,351)	177,209	163,767
Income tax expense (benefit)	(18,546)	(15,083)	570	561
Accumulated other comprehensive loss	$ 56,417	$ 45,858	$ 105	$ 139

The following table shows the estimated amounts that will be amortized from accumulated other comprehensive loss and regulatory assets and liabilities into net periodic benefit cost in 2020 (dollars in thousands):

	Pension	Other Benefits
Net actuarial loss	$ 33,642	$ —
Prior service credit	—	(37,575)
Total amounts estimated to be amortized from accumulated other comprehensive loss (gain) and regulatory assets (liabilities) in 2020	$ 33,642	$ (37,575)

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,		
	2019	2018	2019	2018	2017
Discount rate – pension	3.30%	4.34%	4.34%	3.65%	4.08%
Discount rate – other benefits	3.42%	4.39%	4.39%	3.71%	4.17%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%
Expected long-term return on plan assets - pension	N/A	N/A	6.25%	6.05%	6.55%
Expected long-term return on plan assets - other benefits	N/A	N/A	5.40%	5.40%	6.05%
Initial healthcare cost trend rate (pre-65 participants)	7.00%	7.00%	7.00%	7.00%	7.00%
Initial healthcare cost trend rate (post-65 participants)	4.75%	4.75%	4.75%	4.75%	5.00%
Ultimate healthcare cost trend rate	4.75%	4.75%	4.75%	4.75%	5.00%
Number of years to ultimate trend rate (pre-65 participants)	6	7	7	8	4

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 2020, we are assuming a 5.75% long-term rate of return for pension assets and 5.00% (before tax) for other benefit assets, which we believe is reasonable given our asset allocation in relation to historical and expected performance.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In selecting our healthcare trend rates, we consider past performance and forecasts of healthcare costs. A one percentage point change in the assumed initial and ultimate healthcare cost trend rates would have the following effects on our December 31, 2019 amounts (dollars in thousands):

	1% Increase	1% Decrease
Effect on other postretirement benefits expense, after consideration of amounts capitalized or billed to electric plant participants	$ 9,299	$ (3,827)
Effect on service and interest cost components of net periodic other postretirement benefit costs	9,434	(7,257)
Effect on the accumulated other postretirement benefit obligation	124,073	(97,710)

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-generating assets. The target allocation between return-generating 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 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-generating assets are intended to provide a reasonable long-term rate of investment return with a prudent level of volatility. Return-generating assets are composed of U.S. equities, international equities, and alternative investments. International equities include investments in both developed and emerging markets. Alternative investments include investments in real estate, private equity and various other strategies. The plan may also hold investments in return-generating 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 2019, the target and actual allocation for the pension plan at December 31, 2019 are as follows:

	Pension	
	Target Allocation	Actual Allocation
Long-term fixed income assets	62%	63%
Return-generating assets	38%	37%
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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

Asset Class	Target Allocation
Equities in US and other developed markets	18%
Equities in emerging markets	6%
Alternative investments	14%
Total	38%

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, 2019, 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, 2019:

	Other Benefits
	Actual Allocation
Long-term fixed income assets	68%
Return-generating assets	32%
Total	100%

See Note 14 for a discussion on the fair value hierarchy and how fair value methodologies are applied. The plans invest directly in fixed income, U.S. Treasury Futures Contracts, and equity securities, in addition to investing indirectly in fixed income securities, equity securities and real estate through the use of mutual funds, partnerships and common and collective trusts. Equity securities held directly by the plans are valued using quoted active market prices from the published exchange on which the equity security trades, and are classified as Level 1. U.S. Treasury Futures Contracts are valued using the quoted active market prices from the exchange on which they trade, and are classified as Level 1. Fixed income securities issued by the U.S. Treasury held directly by the plans are valued using quoted active market prices, and are classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies are primarily valued using quoted inactive market prices, or quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield, maturity and credit quality. These instruments are classified as Level 2.

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

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

NAV for trusts investing in real estate is derived from the appraised values of the trust's underlying real estate assets. As of December 31, 2019, the plans were able to transact in the common and collective trusts at NAV.

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 and assets of privately held portfolio companies. Certain partnerships also include funding commitments that may require the plan to contribute up to $50 million to these partnerships; as of December 31, 2019, 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, 2019, by asset category, are as follows (dollars in thousands):

	Level 1	Level 2	Other (a)	Total
Pension Plan:				
Cash and cash equivalents	$ 9,370	$ —	$ —	$ 9,370
Fixed income securities:				
Corporate	—	1,541,729	—	1,541,729
U.S. Treasury	406,112	—	—	406,112
Other (b)	—	92,240	—	92,240
Common stock equities (c)	250,829	—	—	250,829
Mutual funds (d)	185,928	—	—	185,928
Common and collective trusts:				
Equities	—	—	392,403	392,403
Real estate	—	—	171,645	171,645
Fixed Income	—	—	98,065	98,065
Partnerships	—	—	103,796	103,796
Short-term investments and other (e)	—	—	66,234	66,234
Total	$ 852,239	$ 1,633,969	$ 832,143	$ 3,318,351
Other Benefits:				
Cash and cash equivalents	$ 2,184	$ —	$ —	$ 2,184
Fixed income securities:				
Corporate	—	202,640	—	202,640
U.S. Treasury	353,650	—	—	353,650
Other (b)	—	7,999	—	7,999
Common stock equities (c)	146,316	—	—	146,316
Mutual funds (d)	14,351	—	—	14,351
Common and collective trusts:				
Equities	—	—	83,648	83,648
Real estate	—	—	19,806	19,806
Short-term investments and other (e)	2,881	—	4,019	6,900
Total	$ 519,382	$ 210,639	$ 107,473	$ 837,494

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2018, by asset category, are as follows (dollars in thousands):

	Level 1	Level 2	Other (a)	Total
Pension Plan:				
Cash and cash equivalents	$ 451	$ —	$ —	$ 451
Fixed income securities:				
Corporate	—	1,237,744	—	1,237,744
U.S. Treasury	372,649	—	—	372,649
Other (b)	—	78,902	—	78,902
Common stock equities (c)	196,661	—	—	196,661
Mutual funds (d)	120,976	—	—	120,976
Common and collective trusts:				
Equities	—	—	272,926	272,926
Real estate	—	—	165,123	165,123
Fixed Income	—	—	86,483	86,483
Partnerships	—	—	125,217	125,217
Short-term investments and other (e)	—	—	76,344	76,344
Total	$ 690,737	$ 1,316,646	$ 726,093	$ 2,733,476
Other Benefits:				
Cash and cash equivalents	$ 93	$ —	$ —	$ 93
Fixed income securities:				
Corporate	—	163,286	—	163,286
U.S. Treasury	318,017	—	—	318,017
Other (b)	—	7,531	—	7,531
Common stock equities (c)	129,199	—	—	129,199
Mutual funds (d)	10,963	—	—	10,963
Common and collective trusts:				
Equities	—	—	65,720	65,720
Real estate	—	—	19,054	19,054
Short-term investments and other (e)	3,633	—	6,181	9,814
Total	$ 461,905	$ 170,817	$ 90,955	$ 723,677

(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 $150 million in 2019, $50 million in 2018, and $100 million in 2017. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to $100 million per year during the 2020-2022 period. With regard to contributions to our other postretirement benefit plan, we did not make a contribution in 2019 and 2018. We made a contribution of approximately $1 million in 2017. We do not expect to make any contributions over the next three years to our other postretirement benefit plans. The Company was reimbursed $30 million in 2019 and $72 million in 2018 for prior years retiree medical claims from the other postretirement benefit plan trust assets. The Company was not reimbursed in 2017.

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	Other Benefits
2020	$ 199,395	$ 31,531
2021	201,597	32,777
2022	206,618	33,566
2023	213,208	34,415
2024	218,150	34,468
Years 2025-2029	1,111,171	174,607

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 2019, 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 $11 million for 2019, $11 million for 2018, and $10 million for 2017.

9. 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 2020 through 2050. 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 19 for a discussion of VIEs.

On January 1, 2019 we adopted new lease accounting guidance (see Note 3). We elected the transition method that allows us to apply the new lease guidance on the date of adoption, January 1, 2019, and will not retrospectively adjust prior periods. We also elected certain transition practical expedients that allow us to not reassess (a) whether any expired or existing contracts are or contain leases, (b) the lease classification for any expired or existing leases and (c) initial direct costs for any existing leases. These practical expedients apply to leases that commenced prior to January 1, 2019. Furthermore, we elected the practical expedient transition provisions relating to the treatment of existing land easements.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On January 1, 2019 the adoption of this new accounting standard resulted in the recognition on our Consolidated Balance Sheets of approximately $194 million of right-of-use lease assets and $119 million of lease liabilities relating to our operating lease arrangements. The right-of-use lease assets include $85 million of prepaid lease costs that have been reclassified from other deferred debits, and $10 million of deferred lease costs that have been reclassified from other current liabilities. In addition to these balance sheet impacts, the adoption of the guidance resulted in expanded lease disclosures, which are included below.

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

	Year Ended December 31, 2019		
	Purchased Power Lease Contracts	Land, Property & Equipment Leases	Total
Operating lease cost	$ 42,190	$ 18,038	$ 60,228
Variable lease cost	113,233	782	114,015
Short-term lease cost	—	4,385	4,385
Total lease cost	$ 155,423	$ 23,205	$ 178,628

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 4). The tables above reflect the lease cost amounts before the effect of regulatory deferral under the PSA and RES. Variable lease costs are recognized in the period the costs are incurred, and primarily relate to renewable purchased power lease contracts. Payments under most renewable purchased power lease contracts are dependent upon environmental factors, and due to the inherent uncertainty associated with the reliability of the fuel source, the payments are considered variable and are excluded from the measurement of lease liabilities and right-of-use lease assets. Certain of our lease agreements have lease terms with non-consecutive periods of use. For these agreements we recognize lease costs during the periods of use. Leases with initial terms of 12 months or less are considered short-term leases and are not recorded on the balance sheet.

Lease disclosures relating to 2018 and 2017 are presented under prior lease accounting guidance. Lease expense recognized in the Consolidated Statements of Income was $18 million in 2018 and $18 million in 2017, these amounts do not include purchased power lease contracts. Operating lease cost for purchased power lease contracts was $47 million in 2018 and $60 million in 2017. In addition, contingent rents for purchased power lease contracts was $109 million in 2018 and $100 million in 2017. These purchased power lease costs 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 4).

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

	December 31, 2019		
Year	Purchased Power Lease Contracts (a)	Land, Property & Equipment Leases	Total
2020	$ —	$ 14,698	$ 14,698
2021	—	11,963	11,963
2022	—	8,331	8,331
2023	—	6,326	6,326
2024	—	4,141	4,141
Thereafter	—	38,697	38,697
Total lease commitments	—	84,156	84,156
Less imputed interest	—	19,571	19,571
Total lease liabilities	$ —	$ 64,585	$ 64,585

(a) As of December 31, 2019, we had no operating lease liabilities relating to purchased power lease contracts. See discussion below regarding executed contracts with commencement dates beginning in June 2020.

We recognize lease assets and liabilities upon lease commencement. At December 31, 2019, we have additional lease arrangements that have been executed, but have not yet commenced. These arrangements primarily relate to purchased power lease contracts. These leases have commencement dates beginning in June 2020 with terms ending through October 2027. We expect the total fixed consideration paid for these arrangements, which includes both lease and nonlease payments, will approximate $705 million over the term of the arrangements.

The following table provides information related to estimated future minimum operating lease payments (dollars in thousands):

	December 31, 2018		
Year	Purchased Power Lease Contracts	Land, Property & Equipment Leases	Total
2019	$ 54,499	$ 13,747	$ 68,246
2020	—	12,428	12,428
2021	—	9,478	9,478
2022	—	6,513	6,513
2023	—	5,359	5,359
Thereafter	—	42,236	42,236
Total future lease commitments	$ 54,499	$ 89,761	$ 144,260

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following tables provide other additional information related to operating lease liabilities:

	December 31, 2019
Weighted average remaining lease term	13 years
Weighted average discount rate (a)	3.71%

(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.

	Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities - operating cash flows (dollars in thousands):	$ 69,075

10. 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, 2019 (dollars in thousands):

	Percent Owned		Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating facilities:					
Palo Verde Units 1 and 3	29.1%		$ 1,877,748	$ 1,102,609	$ 22,071
Palo Verde Unit 2 (a)	16.8%		634,545	377,722	11,831
Palo Verde Common	28.0%	(b)	746,653	290,084	46,570
Palo Verde Sale Leaseback		(a)	351,050	249,144	—
Four Corners Generating Station	63.0%		1,520,171	559,272	44,842
Cholla common facilities (c)	50.5%		184,608	95,720	1,323
Transmission facilities:					
ANPP 500kV System	33.5%	(b)	133,396	51,248	2,723
Navajo Southern System	26.7%	(b)	89,672	31,985	194
Palo Verde — Yuma 500kV System	19.0%	(b)	15,274	6,486	4,886
Four Corners Switchyards	63.0%	(b)	69,994	16,674	2,395
Phoenix — Mead System	17.1%	(b)	39,355	18,570	53
Palo Verde — Rudd 500kV System	50.0%		93,112	26,719	317
Morgan — Pinnacle Peak System	64.6%	(b)	117,752	18,822	—
Round Valley System	50.0%		515	164	—
Palo Verde — Morgan System	88.9%	(b)	238,689	13,146	—
Hassayampa — North Gila System	80.0%		143,422	12,676	—
Cholla 500kV Switchyard	85.7%		7,651	1,597	535
Saguaro 500kV Switchyard	60.0%		20,425	12,949	—
Kyrene — Knox System	50.0%		578	315	—

(a) See Note 19.
(b) Weighted-average of interests.
(c) PacifiCorp owns Cholla Unit 4 (see Note 4 for additional information) and APS operates the unit for PacifiCorp. The common facilities at Cholla are jointly-owned.

See "Navajo Plant" in Note 4 for more details.

11. Commitments and Contingencies

Palo Verde Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the DOE in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE's breach of the Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste ("Standard Contract") for failing to accept Palo Verde's spent nuclear fuel and high level waste from January 1, 2007 through June 30, 2011, as it was required to do 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, stipulating to a dismissal of the lawsuit and payment by 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, as amended, provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2019.

APS has submitted five claims pursuant to the terms of the August 18, 2014 settlement agreement, for five separate time periods during July 1, 2011 through June 30, 2018. The DOE has approved and paid $84.3 million for these claims (APS's share is $24.5 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, 2019, APS filed its next claim pursuant to the terms of the August 18, 2014 settlement agreement in the amount of $16 million (APS's share is $4.7 million). On February 11, 2020, the DOE approved a payment of $15.4 million (APS's share is $4.5 million).

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 of up to approximately $13.9 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 ("ANI"). The remaining balance of approximately $13.5 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, 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 $25.5 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. In addition, NEIL policies contain rating triggers that would result in APS providing approximately $73.4 million of collateral assurance within 20 business days of a rating downgrade to non-investment grade. 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 2020 and 2043 that include required purchase provisions. APS estimates the contract requirements to be approximately $590 million in 2020; $613 million in 2021; $624 million in 2022; $616 million in 2023; $581 million in 2024; and $5.5 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 9).

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,					
	2020	2021	2022	2023	2024	Thereafter
Coal take-or-pay commitments (a)	$ 185,347	$ 186,554	$ 187,400	$ 189,120	$ 193,192	$ 1,240,964

(a) Total take-or-pay commitments are approximately $2.2 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):

	Year Ended December 31,		
	2019	2018	2017
Total purchases	$ 204,888	$ 206,093	$ 165,220

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 $36 million in 2020; $35 million in 2021; $31 million in 2022; $30 million in 2023; $28 million in 2024; and $133 million thereafter. These amounts do not include purchases of renewable energy credits that are bundled with energy.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Coal Mine Reclamation Obligations

APS must reimburse certain coal providers for amounts incurred 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 $166 million at December 31, 2019 and $213 million at December 31, 2018. Under our current coal supply agreements, APS expects to make payments for the final mine reclamation as follows: $17 million in 2020; $16 million in 2021; $17 million in 2022; $18 million in 2023; $19 million in 2024; and $88 million thereafter. Any amendments to current coal supply agreements may change the timing of the contribution. Portions of these funds will be held in an escrow account and distributed to certain coal providers under the terms of the applicable coal supply agreements.

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 ("PRPs"). PRPs may be strictly, and often are 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"). Based upon discussions between the OU3 working group parties and EPA, along with the results of recent technical analyses prepared by the OU3 working group to supplement the RI/FS for OU3, APS anticipates finalizing the RI/FS in the spring or summer of 2020. We estimate that our costs related to this investigation and study will be approximately $2 million. We anticipate incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

On August 6, 2013, 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 service provider lawsuit, filed a third-party complaint seeking contribution for its liability, if any, from APS and 28 other third-party defendants. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of both conventional pollutants and greenhouse gases, water quality, wastewater discharges, solid waste, hazardous waste, and CCRs. These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates, but cannot predict whether it will obtain such recovery. The following proposed and final rules involve material compliance costs to APS.

Regional Haze Rules. APS has received the final rulemaking imposing new 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. 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 below for details of the Cholla BART approval.

Four Corners. 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. See "Four Corners - 4CA Matter" below for a discussion of the NTEC purchase. 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.

Cholla. APS believed that EPA's original 2012 final rule establishing controls constituting BART for Cholla, which would require installation of SCR controls, was unsupported and that EPA had no basis for disapproving Arizona's State Implementation Plan ("SIP") and promulgating a FIP that was inconsistent with the state's considered BART determinations under the regional haze program. In September 2014, APS met with EPA to propose a compromise BART strategy, whereby APS would permanently close Cholla Unit 2 and cease burning coal at Units 1 and 3 by the mid-2020s. (See "Cholla" in Note 4 for information regarding future plans for Cholla and details related to the resulting regulatory asset.) APS made the proposal with the understanding that additional emission control equipment is unlikely to be required in the future because retiring and/or converting the units as contemplated in the proposal is more cost effective than, and will result in increased visibility improvement over, the BART requirements for oxides of nitrogen ("NOx") imposed through EPA's BART FIP. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect for Cholla on April 26, 2017.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA") and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard 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, 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.

- 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.

- Based on an August 21, 2018 D.C. Circuit decision, which vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments, EPA recently proposed corresponding changes to federal CCR regulations. On November 4, 2019, EPA proposed that all unlined CCR surface impoundments, regardless of their impact (or lack thereof) upon surrounding groundwater, must cease operation and initiate closure by August 31, 2020 (with an optional three-month extension as needed for the completion of alternative disposal capacity).

- On November 4, 2019, EPA also proposed to change the manner by which facilities that have committed to cease burning coal in the near-term may qualify for alternative closure. Such qualification would allow CCR disposal units at these plants to continue operating, even though they would otherwise be subject to forced closure under the federal CCR regulations. EPA's proposal regarding alternative closure would require express EPA authorization for such facilities to continue operating their CCR disposal units under alternative closure.

We cannot at this time predict the outcome of these regulatory proceedings or when the EPA will take final action. 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 $22 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $15 million. The Navajo Plant currently disposes of CCR in a dry landfill storage area. To comply with the CCR rule for the Navajo Plant, APS's share of incremental costs is 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 cease operating and initiate closure by October 31, 2020. APS initiated an assessment of corrective measures on January 14, 2019 and expects such assessment will continue through mid- to late-2020. As part of this assessment, APS continues to gather additional groundwater data and perform remedial evaluations as to the CCR disposal units at Cholla and Four Corners undergoing corrective action. In addition, APS will solicit input from the public, host public hearings, and select remedies 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.

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 those regulations had been stayed pending judicial review.

The ACE regulations are based upon measures that can be implemented to improve the heat rate of steam-electric power plants, specifically coal-fired EGUs. In contrast with the CPP, EPA's ACE regulations would not involve utility-level generation dispatch shifting away from coal-fired generation and toward renewable energy resources and natural gas-fired combined cycle power plants. EPA's ACE regulations provide states and EPA regions such as the Navajo Nation with three years to develop plans establishing source-specific standards of performance based upon application of the ACE rule's heat-rate improvement emission guidelines. While corresponding New Source Review ("NSR") reform regulations were proposed as part of EPA's initial ACE proposal, the finalized ACE regulations did not include such reform measures. EPA announced that it will be taking final action on EPA's NSR reform proposal for EGUs in the near future.

We cannot at this time predict the outcome of EPA's regulatory actions repealing and replacing the CPP. Various state governments, industry organizations, and environmental and public-health public interest groups have filed lawsuits in the D.C. Circuit challenging the legality of EPA's action, both in repealing the CPP and issuing the ACE regulations. In addition, to the extent that the ACE regulations go into effect as finalized, it is not yet clear how the state of Arizona or EPA will implement these regulations as applied to APS's coal-fired EGUs. In light of these uncertainties, APS is still evaluating the impact of the ACE regulations on its coal-fired generation fleet.

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 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 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.

Federal Agency Environmental Lawsuit Related to Four Corners

On April 20, 2016, several environmental groups filed a lawsuit against the Office of Surface Mining Reclamation and Enforcement ("OSM") and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both the Endangered Species Act ("ESA") and the National Environmental Policy Act ("NEPA") in providing the federal approvals necessary to extend operations at the Four Corners Power Plant and the adjacent Navajo Mine past July 6, 2016. APS filed a motion to intervene in the proceedings, which was granted on August 3, 2016.

On September 15, 2016, NTEC, the company that owns the adjacent mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. On September 11, 2017, the Arizona District Court issued an order granting NTEC's motion, dismissing the litigation with prejudice, and terminating the proceedings. On November 9, 2017, the environmental group plaintiffs appealed the district court order dismissing their lawsuit. On July 29, 2019, the Ninth Circuit Court of Appeals affirmed the September 2017 dismissal of the lawsuit, after which the environmental group plaintiffs petitioned the Ninth Circuit for rehearing on September 12, 2019. The Ninth Circuit denied this petition for rehearing on December 11, 2019.

Four Corners National Pollutant Discharge Elimination System ("NPDES") 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 effluent limitation guidelines 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. This permit is now subject to a petition for review before the EPA Environmental Appeals Board, based upon a November 1, 2019 filing by several environmental groups. We cannot predict the outcome of this review and whether the review will have a material impact on our 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 had the option to purchase the 7% interest and ultimately purchased the interest on July 3, 2018. NTEC purchased the 7% interest at 4CA's book value, approximately $70 million, and is paying 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note. 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.

The 2016 Coal Supply Agreement contained alternate pricing terms for the 7% interest in the event NTEC did not purchase the interest. Until the time that NTEC purchased the 7% interest, the alternate pricing provisions were applicable to 4CA as the holder of the 7% interest. These terms included a formula under which NTEC must make certain payments to 4CA for reimbursement of operations and maintenance costs and a specified rate of return, offset by revenue generated by 4CA's power sales. The amount under this formula for calendar year 2018 (up to the date that NTEC purchased the 7% interest) is approximately $10 million, which was due to 4CA on December 31, 2019. Such payment was satisfied in January 2020 by NTEC directing to 4CA a prepayment from APS of future coal payment obligations.

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. As of December 31, 2019, standby letters of credit totaled $1.7 million and will expire in 2020. As of December 31, 2019, surety bonds expiring through 2020 totaled $14 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, 2019. 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.) 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 to be immaterial.

In connection with BCE's acquisition of minority ownership positions in the Clear Creek and Nobles 2 wind farms, 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 reduce as payments are made under the respective guaranteed agreements. The Equity Contribution Guarantees are currently anticipated to be terminated upon completion of construction of the respective projects, which is anticipated to occur prior to December 31, 2020, and the PTC Guarantees (approximately $40 million as of December 31, 2019) are currently expected to be terminated ten years following the commercial operation date of the applicable project.

12. Asset Retirement Obligations

In 2019, APS received updated decommissioning estimates for the Navajo Plant closure in December 2019, which resulted in a decrease to the ARO in the amount of $8 million (see Note 4 for additional information). In addition, APS received a new decommissioning study for Palo Verde. This resulted in a decrease to the ARO in the amount of $89 million, a decrease in plant in service of $80 million and a reduction in the regulatory liability of $9 million.

In 2018, APS recognized an ARO for the removal of hazardous waste containing solar panels at all of our utility scale solar plants, which resulted in an increase to the ARO in the amount of $14 million. In addition, due to the sale of 4CA assets to NTEC in 2018 (see Note 11 for more information on 4CA matters) there was a decrease to the ARO of $9 million. APS recognized an ARO of $7 million for rooftop solar removals in accordance with the obligations included in the customer contracts, which requires APS to remove the panels at the end of the contract life and includes the costs for the disposal of hazardous materials in accordance with environmental regulations. Finally, APS has other ARO adjustments resulting in a net decrease of $1 million.

The following table shows the change in our asset retirement obligations for 2019 and 2018 (dollars in thousands):

	2019	2018
Asset retirement obligations at the beginning of year	$ 726,545	$ 679,529
Changes attributable to:		
Accretion expense	39,726	36,876
Settlements	(12,591)	(9,726)
Estimated cash flow revisions	(96,462)	2,002
Newly incurred or acquired obligations	—	17,864
Asset retirement obligations at the end of year	$ 657,218	$ 726,545

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 4.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

13. Selected Quarterly Financial Data (Unaudited)

Consolidated quarterly financial information for 2019 and 2018 is provided in the tables below (dollars in thousands, except per share amounts). Weather conditions cause significant seasonal fluctuations in our revenues; therefore, results for interim periods do not necessarily represent results expected for the year.

	2019 Quarter Ended				2019
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$ 740,530	$ 869,501	$ 1,190,787	$ 670,391	$ 3,471,209
Operations and maintenance	245,634	227,543	238,582	229,857	941,616
Operating income	60,084	196,589	403,290	11,997	671,960
Income taxes	2,418	17,080	53,266	(88,537)	(15,773)
Net income	22,791	149,019	317,149	68,854	557,813
Net income attributable to common shareholders	17,918	144,145	312,276	63,981	538,320
Earnings Per Share:					
Net income attributable to common shareholders — Basic	$ 0.16	$ 1.28	$ 2.78	$ 0.57	$ 4.79
Net income attributable to common shareholders — Diluted	0.16	1.28	2.77	0.57	4.77

	2018 Quarter Ended				2018
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$ 692,714	$ 974,123	$ 1,268,034	$ 756,376	$ 3,691,247
Operations and maintenance	265,682	268,397	246,545	256,120	1,036,744
Operating income	31,334	242,162	433,307	66,884	773,687
Income taxes	(1,265)	44,039	84,333	6,795	133,902
Net income	8,094	171,612	319,885	30,949	530,540
Net income attributable to common shareholders	3,221	166,738	315,012	26,076	511,047
Earnings Per Share:					
Net income attributable to common shareholders — Basic	$ 0.03	$ 1.49	$ 2.81	$ 0.23	$ 4.56
Net income attributable to common shareholders — Diluted	0.03	1.48	2.80	0.23	4.54

Selected Quarterly Financial Data (Unaudited) - APS

APS's quarterly financial information for 2019 and 2018 is as follows (dollars in thousands):

	2019 Quarter Ended				2019
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$ 740,530	$ 869,501	$ 1,190,787	$ 670,391	$ 3,471,209
Operations and maintenance	240,375	224,143	235,440	226,758	926,716
Operating income	65,377	200,018	406,465	15,124	686,984
Net income attributable to common shareholder	28,276	150,176	318,870	67,949	565,271

	2018 Quarter Ended				2018
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$ 692,006	$ 971,963	$ 1,267,997	$ 756,376	$ 3,688,342
Operations and maintenance	254,601	251,999	226,346	236,281	969,227
Operating income	37,878	251,590	453,547	86,753	829,768
Net income attributable to common shareholder	9,599	177,825	338,366	44,475	570,265

14. 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 — 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 include long-dated derivative transactions where valuations are unobservable due to the length of the transaction, options, and transactions in locations where observable market data does not exist. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Thus, a valuation may be classified in Level 3 even though the valuation may include significant inputs that are readily observable. We maximize the use of observable inputs and minimize the use of unobservable inputs. We rely primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities. If market data is not readily available, inputs may reflect our own assumptions about the inputs market participants would use. Our assessment of the inputs and the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities as well as their placement within the fair value hierarchy levels. We assess whether a market is active by obtaining observable broker quotes, reviewing actual market activity, and assessing the volume of transactions. We consider broker quotes observable inputs when the quote is binding on the broker, we can validate the quote with market activity, or we can determine that the inputs the broker used to arrive at the quoted price are observable.

Certain instruments have been valued using the concept of NAV, as a practical expedient. These instruments are typically structured as investment companies offering shares or units to multiple investors for the purpose of providing a return. These instruments are similar to mutual funds; however, their NAV is generally not published and publicly available, nor are these instruments traded on an exchange. Instruments valued using NAV, as a practical expedient are included in our fair value disclosures however, in accordance with GAAP are not classified within the fair value hierarchy levels.

Recurring Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, and investments held in the nuclear decommissioning trust 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 8 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 — 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 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. Our classification of instruments as Level 3 is primarily reflective of the long-term nature of our energy transactions.

Our energy risk management committee, consisting of officers and key management personnel, oversees our energy risk management activities to ensure compliance with our stated energy risk management policies. We have a risk control function that is responsible for valuing our derivative commodity instruments in accordance with established policies and procedures. The risk control function reports to the chief financial officer's organization.

Investments Held in Nuclear Decommissioning Trust and Other Special Use Funds

The nuclear decommissioning trust 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 medical trust. See Note 20 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 trust's equity security investments are held indirectly through commingled funds. The commingled funds are valued using the funds' NAV as a practical expedient. The funds' NAV is primarily derived from the quoted active market prices of the underlying equity securities held by the funds. We may transact in these commingled funds on a semi-monthly basis at the NAV. The commingled funds are maintained by a bank and hold investments in accordance with the stated objective of tracking the performance of the S&P 500 Index. Because the commingled funds' shares are offered to a limited group of investors, they are not considered to be traded in an active market. As these instruments are valued using NAV, as a practical expedient, they have not been classified within the fair value hierarchy.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The nuclear decommissioning trust 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.

Fair Value Tables

The following table presents the fair value at December 31, 2019 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	$ —	$ 551	$ 33	$ (69)	(a)	$ 515
Nuclear decommissioning trust:						
Equity securities	10,872	—	—	2,401	(b)	13,273
U.S. commingled equity funds	—	—	—	518,844	(c)	518,844
U.S. Treasury debt	160,607	—	—	—		160,607
Corporate debt	—	115,869	—	—		115,869
Mortgage-backed securities	—	118,795	—	—		118,795
Municipal bonds	—	73,040	—	—		73,040
Other fixed income	—	10,347	—	—		10,347
Subtotal nuclear decommissioning trust	171,479	318,051	—	521,245		1,010,775
Other special use funds:						
Equity securities	7,142	—	—	474	(b)	7,616
U.S. Treasury debt	232,848	—	—	—		232,848
Municipal bonds	—	4,631	—	—		4,631
Subtotal other special use funds	239,990	4,631	—	474		245,095
Total assets	$ 411,469	$ 323,233	$ 33	$ 521,650		$ 1,256,385
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (67,992)	$ (3,429)	$ (711)	(a)	$ (72,132)

(a) Represents counterparty netting, margin, and collateral. See Note 17.
(b) Represents net pending securities sales and purchases.
(c) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value at December 31, 2018 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
Assets						
Cash equivalents	$ 1,200	$ —	$ —	$ —		$ 1,200
Risk management activities — derivative instruments:						
Commodity contracts	—	3,140	2	(2,029)	(a)	1,113
Nuclear decommissioning trust:						
Equity securities	5,203	—	—	2,148	(b)	7,351
U.S. commingled equity funds	—	—	—	396,805	(c)	396,805
U.S. Treasury debt	148,173	—	—	—		148,173
Corporate debt	—	96,656	—	—		96,656
Mortgage-backed securities	—	113,115	—	—		113,115
Municipal bonds	—	79,073	—	—		79,073
Other fixed income	—	9,961	—	—		9,961
Subtotal nuclear decommissioning trust	153,376	298,805	—	398,953		851,134
Other special use funds:						
Equity securities	45,130	—	—	593	(b)	45,723
U.S. Treasury debt	173,310	—	—	—		173,310
Municipal bonds	—	17,068	—	—		17,068
Subtotal other special use funds	218,440	17,068	—	593		236,101
Total assets	$ 373,016	$ 319,013	$ 2	$ 397,517		$ 1,089,548
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (52,696)	$ (8,216)	$ 875	(a)	$ (60,037)

(a) Represents counterparty netting, margin, and collateral. See Note 17.
(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. 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 4).

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, 2019 and December 31, 2018:

	December 31, 2019 Fair Value (thousands)					
Commodity Contracts	**Assets**	**Liabilities**	**Valuation Technique**	**Significant Unobservable Input**	**Range**	**Weighted-Average**
Electricity:						
Forward Contracts (a)	$ 33	$ 819	Discounted cash flows	Electricity forward price (per MWh)	$22.18 - $22.18	$ 22.18
Natural Gas:						
Forward Contracts (a)	—	2,610	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.33 -$ 2.78	$ 2.49
Total	$ 33	$ 3,429				

(a) Includes swaps and physical and financial contracts.

	December 31, 2018 Fair Value (thousands)					
Commodity Contracts	**Assets**	**Liabilities**	**Valuation Technique**	**Significant Unobservable Input**	**Range**	**Weighted-Average**
Electricity:						
Forward Contracts (a)	$ —	$ 2,456	Discounted cash flows	Electricity forward price (per MWh)	$17.88 - $37.03	$ 26.10
Natural Gas:						
Forward Contracts (a)	2	5,760	Discounted cash flows	Natural gas forward price (per MMBtu)	$1.79 - $2.92	$ 2.48
Total	$ 2	$ 8,216				

(a) Includes swaps and physical and financial contracts.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the changes in fair value for our risk management activities' assets and liabilities that are measured at fair value on a recurring basis using Level 3 inputs for the years ended December 31, 2019 and 2018 (dollars in thousands):

	Year Ended December 31,	
Commodity Contracts	**2019**	**2018**
Net derivative balance at beginning of period	$ (8,214)	$ (18,256)
Total net gains (losses) realized/unrealized:		
Included in earnings	—	—
Included in OCI	—	—
Deferred as a regulatory asset or liability	(13,457)	(1,130)
Settlements	12,250	(787)
Transfers into Level 3 from Level 2	(6,512)	(12,830)
Transfers from Level 3 into Level 2	12,537	24,789
Net derivative balance at end of period	$ (3,396)	$ (8,214)
Net unrealized gains included in earnings related to instruments still held at end of period	$ —	$ —

Transfers between levels in the fair value hierarchy shown in the table above reflect the fair market value at the beginning of the period and are triggered by a change in the lowest significant input as of the end of the period. We had no significant Level 1 transfers to or from any other hierarchy level. 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 7 for our long-term debt fair values. The NTEC note receivable related to the sale of 4CA's interest in Four Corners bears interest at 3.9% per annum and has a book value of $44.3 million as of December 31, 2019, as presented on the Consolidated Balance Sheets. The carrying amount is not materially different from the fair value of the note receivable and is classified within Level 3 of the fair value hierarchy. See Note 11 for more information on 4CA matters.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

15. Earnings Per Share

The following table presents the calculation of Pinnacle West's basic and diluted earnings per share for continuing operations attributable to common shareholders for the years ended December 31, 2019, 2018 and 2017 (in thousands, except per share amounts):

	2019	2018	2017
Net income attributable to common shareholders	$ 538,320	$ 511,047	$ 488,456
Weighted average common shares outstanding — basic	112,443	112,129	111,839
Net effect of dilutive securities:			
Contingently issuable performance shares and restricted stock units	315	421	528
Weighted average common shares outstanding — diluted	112,758	112,550	112,367
Earnings per weighted-average common share outstanding			
Net income attributable to common shareholders - basic	$ 4.79	$ 4.56	$ 4.37
Net income attributable to common shareholders - diluted	$ 4.77	$ 4.54	$ 4.35

16. 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 2012 Long-Term Incentive Plan ("2012 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 2012 Plan authorizes up to 4.6 million common shares to be available for grant. As of December 31, 2019, 1.6 million common shares were available for issuance under the 2012 Plan. During 2019, 2018, and 2017, the Company granted awards in the form of restricted stock units, stock units, stock grants, and performance shares. Awards granted from 2007 to 2011 were issued under the 2007 Long-Term Incentive Plan ("2007 Plan"), and no new awards may be granted under the 2007 Plan.

Stock-Based Compensation Expense and Activity

Compensation cost included in net income for stock-based compensation plans was $18 million in 2019, $20 million in 2018, and $21 million in 2017. The compensation cost capitalized is immaterial for all years. Income tax benefits related to stock-based compensation arrangements were $7 million in 2019, $7 million in 2018, and $15 million in 2017.

As of December 31, 2019, there were approximately $9 million of unrecognized compensation costs related to nonvested stock-based compensation arrangements. We expect to recognize these costs over a weighted-average period of 2 years.

The total fair value of shares vested was $21 million in 2019, $24 million in 2018 and $22 million in 2017.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table is a summary of awards granted and the weighted-average grant date fair value for the three years ended 2019, 2018 and 2017:

	Restricted Stock Units, Stock Grants, and Stock Units (a)			Performance Shares (b)		
	2019	2018	2017	2019	2018	2017
Units granted	109,106	132,997	161,963	142,874	171,708	147,706
Weighted-average grant date fair value	$ 89.15	$ 77.51	$ 72.60	$ 92.16	$ 76.56	$ 78.99

(a) Units granted includes awards that will be cash settled of 48,972 in 2019, 66,252 in 2018, and 67,599 in 2017.
(b) Reflects the target payout level.

The following table is a summary of the status of non-vested awards as of December 31, 2019 and changes during the year:

	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 January 1, 2019	270,991	$ 74.39	312,384	$ 77.67
Granted	109,106	89.15	142,874	92.16
Vested	(132,102)	73.48	(139,214)	78.99
Forfeited (c)	(5,383)	80.10	(9,074)	81.03
Nonvested at December 31, 2019	242,612 (a)	81.38	306,970	83.65
Vested Awards Outstanding at December 31, 2019	67,148		139,214	

(a) Includes 141,621 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 $5 million, $4 million and $4 million in 2019, 2018 and 2017, respectively. This includes cash used to settle restricted stock units of $5 million, $5 million and $4 million in 2019, 2018 and 2017, 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. Restricted stock units 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; however, awards granted to retirement-eligible employees will vest upon the employee's retirement. Awardees elect to receive payment in either 100% stock, 100% cash, or 50% in cash and 50% in stock. Restricted stock unit awards typically include a dividend equivalent feature. This feature allows each award to accrue dividend rights equal to the dividends they would have received had they directly owned the stock. Interest on dividend rights compounds quarterly. If the award is forfeited the employee is not entitled to the dividends on those shares.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In December 2012, the Company granted a retention award of 50,617 performance-linked restricted stock units to the Chairman of the Board and Chief Executive Officer of Pinnacle West. This award vested on December 31, 2016, because he remained employed with the Company through that date. The Board did increase the number of awards that vested by 33,745 restricted stock units, payable in stock because certain performance requirements were met. In February 2017, 84,362 restricted stock units were released.

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

Stock grants are issued to non-officer members of the Board of Directors. They may elect to receive the stock grant, or to defer receipt until a later date and receive stock units in lieu of the stock grant. 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. Each stock unit is convertible to one share of stock. The stock units accrue dividend rights, equal to the amount of dividends the Directors would have received had they directly owned stock equal to the number of vested restricted stock units or stock units from the date of grant to the date of payment, plus interest compounded quarterly. The dividends and interest are paid, based on the Director's election, in either stock, cash, or 50% in cash and 50% in stock.

Performance Share Awards

Performance share awards are granted to officers and key employees. The awards contain two separate performance 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. For the first criteria, the number of shares that will vest is based on non-financial performance metrics (i.e., the metric component). The other 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 exact number of shares issued will vary from 0% to 200% of the target award. Shares received include dividend rights paid in stock equal to the amount of dividends that recipients would have received had they directly owned stock, equal to the number of vested performance shares from the date of grant to the date of payment plus interest compounded quarterly. If the award is forfeited or if the performance criteria are not achieved, the employee is not entitled to the dividends on those shares.

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 metric component of the award 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 metric component at each balance sheet date. If the metric component criteria are not ultimately achieved, no compensation cost is recognized relating to the metric component, and any previously recognized compensation cost is reversed. Compensation cost relating to the TSR component of the award 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.

17. Derivative Accounting

Derivative financial instruments are used to manage exposure to commodity price and transportation costs of electricity, natural gas, coal, 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 fuels. 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 14 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.

For its regulated operations, APS defers for future rate treatment 100% of the unrealized gains and losses on derivatives pursuant to the PSA mechanism that would otherwise be recognized in income. Realized gains and losses on derivatives are deferred in accordance with the PSA to the extent the amounts are above or below the Base Fuel Rate (see Note 4). Gains and losses from derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

As of December 31, 2019 and 2018, we had the following outstanding gross notional volume of derivatives, which represent both purchases and sales (does not reflect net position):

		Quantity	
Commodity	**Unit of Measure**	**December 31, 2019**	**December 31, 2018**
Power	GWh	193	250
Gas	Billion cubic feet	257	218

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Gains and Losses from Derivative Instruments

The following table provides information about gains and losses from derivative instruments in designated cash flow accounting hedging relationships during the years ended December 31, 2019, 2018 and 2017 (dollars in thousands):

Commodity Contracts	Financial Statement Location	Year Ended December 31, 2019	2018	2017
Loss Recognized in OCI on Derivative Instruments (Effective Portion)	OCI — derivative instruments	$ —	$ —	$ (59)
Loss Reclassified from Accumulated OCI into Income (Effective Portion Realized) (a)	Fuel and purchased power (b)	(1,512)	(2,000)	(3,519)

(a) During the years ended December 31, 2019, 2018, and 2017, we had no 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 a net loss of $0.8 million before income taxes will be reclassified from accumulated OCI as an offset to the effect of market price changes for the related hedged transactions. In accordance with the PSA, most of these amounts will be recorded as either a regulatory asset or liability and have no immediate effect on earnings.

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments during the years ended December 31, 2019, 2018 and 2017 (dollars in thousands):

Commodity Contracts	Financial Statement Location	Year Ended December 31, 2019	2018	2017
Net Loss Recognized in Income	Operating revenues	$ —	$ (2,557)	$ (1,192)
Net Loss Recognized in Income	Fuel and purchased power (a)	(84,953)	(12,951)	(87,991)
Total		$ (84,953)	$ (15,508)	$ (89,183)

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

Derivative Instruments in the Consolidated Balance Sheets

Our 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 derivative contracts with the counterparty’s non-current derivative contracts, although our master netting arrangements would allow current and non-current positions to be offset in the event of a default. Additionally, in the event of a default, our master netting arrangements would allow for the offsetting of all transactions executed under the master netting arrangement. 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.

As of December 31, 2017, we no longer have derivative instruments that are designated as cash flow hedging instruments.

The following tables provide information about the fair value of our risk management activities reported on a gross basis and the impacts of offsetting as of December 31, 2019 and 2018. These amounts relate to commodity contracts and are located in the assets and liabilities from risk management activities lines of our Consolidated Balance Sheets.

As of December 31, 2019: **(dollars in thousands)**	**Gross Recognized Derivatives (a)**	**Amounts Offset (b)**	**Net Recognized Derivatives**	**Other (c)**	**Amount Reported on Balance Sheet**
Current assets	$ 584	$ (474)	$ 110	$ 405	$ 515
Current liabilities	(38,235)	474	(37,761)	(1,185)	(38,946)
Deferred credits and other	(33,186)	—	(33,186)	—	(33,186)
Total liabilities	(71,421)	474	(70,947)	(1,185)	(72,132)
Total	$ (70,837)	$ —	$ (70,837)	$ (780)	$ (71,617)

(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 $1,185 and cash margin provided to counterparties of $405.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As of December 31, 2018: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$ 3,106	$ (2,149)	$ 957	$ 156	$ 1,113
Investments and other assets	36	(36)	—	—	—
Total assets	3,142	(2,185)	957	156	1,113
Current liabilities	(36,345)	2,149	(34,196)	(1,310)	(35,506)
Deferred credits and other	(24,567)	36	(24,531)	—	(24,531)
Total liabilities	(60,912)	2,185	(58,727)	(1,310)	(60,037)
Total	$ (57,770)	$ —	$ (57,770)	$ (1,154)	$ (58,924)

(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 $1,310 and cash margin provided to counterparties of $156.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by counterparties and have risk management contracts with many counterparties. As of December 31, 2019, Pinnacle West has no counterparties with positive exposures of greater than 10% of risk management assets. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of 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 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 derivative instruments in a net liability position, with investment grade credit contingencies, the counterparties could demand additional collateral if our debt credit rating were to fall below investment grade (below BBB- for Standard & Poor’s or Fitch or Baa3 for Moody’s).

The following table provides information about our derivative instruments that have credit-risk-related contingent features at December 31, 2019 (dollars in thousands):

	December 31, 2019
Aggregate fair value of derivative instruments in a net liability position	$ 71,116
Cash collateral posted	—
Additional cash collateral in the event credit-risk related contingent features were fully triggered (a)	70,519

(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 $95 million if our debt credit ratings were to fall below investment grade.

18. Other Income and Other Expense

The following table provides detail of Pinnacle West's Consolidated other income and other expense for 2019, 2018 and 2017 (dollars in thousands):

	2019	2018	2017
Other income:			
Interest income	$ 10,377	$ 8,647	$ 3,497
Debt return on Four Corners SCR deferral (Note 4)	19,541	16,153	354
Debt return on Ocotillo modernization project (Note 4)	20,282	—	—
Miscellaneous	63	96	155
Total other income	$ 50,263	$ 24,896	$ 4,006
Other expense:			
Non-operating costs	$ (10,663)	$ (10,076)	$ (11,749)
Investment losses — net	(1,835)	(417)	(4,113)
Miscellaneous	(5,382)	(7,473)	(5,677)
Total other expense	$ (17,880)	$ (17,966)	$ (21,539)

Other Income and Other Expense - APS

The following table provides detail of APS's other income and other expense for 2019, 2018 and 2017 (dollars in thousands):

	2019	2018	2017
Other income:			
Interest income	$ 6,998	$ 6,496	$ 2,504
Debt return on Four Corners SCR deferral (Note 4)	19,541	16,153	354
Debt return on Ocotillo modernization project (Note 4)	20,282	—	—
Miscellaneous	63	97	155
Total other income	$ 46,884	$ 22,746	$ 3,013
Other expense:			
Non-operating costs	$ (9,612)	$ (9,462)	$ (10,825)
Miscellaneous	(3,378)	(5,830)	(3,088)
Total other expense	$ (12,990)	$ (15,292)	$ (13,913)

19. 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 2023 under one lease and 2033 under the other two leases. APS will be required to make payments relating to these leases of approximately $23 million annually for the period 2020 through 2023, and about $16 million annually for the period 2024 through 2033. At the end of the lease period, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors.

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

As a result of consolidation, we eliminate lease accounting and instead recognize depreciation expense, resulting in an increase in net income of $19 million for 2019, 2018 and 2017. The increase in net income is entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

Our Consolidated Balance Sheets at December 31, 2019 and December 31, 2018 include the following amounts relating to the VIEs (dollars in thousands):

	December 31, 2019	December 31, 2018
Palo Verde sale leaseback property, plant and equipment, net of accumulated depreciation	$ 101,906	$ 105,775
Equity-Noncontrolling interests	122,540	125,790

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 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 $301 million beginning in 2020, and up to $456 million over the lease extension term.

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.

20. 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 Accounts, 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 14 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 - To fund the future costs APS expects to incur to decommission Palo Verde, APS established external decommissioning trusts in accordance with NRC regulations. 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 other-than-temporary impairments) 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 other-than-temporary impairments) in other regulatory liabilities. Activities relating to APS coal 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 were transferred from APS other postretirement benefit trust assets into the active union employee medical trust in January 2018. These investments may be used to pay active union employee medical costs incurred in the current and future periods. In August 2019, the Company was reimbursed $15 million for prior year active union employee medical claims from the active union employee medical account. The account is invested primarily in fixed income securities. In accordance with the ratemaking treatment, APS has deferred the unrealized gains and losses (including other-than-temporary impairments) in other regulatory liabilities. Activities relating to active union employee medical account investments are included within the other special use funds in the tables 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 trust and other special use fund assets at December 31, 2019 and December 31, 2018 (dollars in thousands):

	December 31, 2019					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity Securities	$ 529,716	$ 7,142	$ 536,858		$ 337,681	$ —
Available for Sale-Fixed Income Securities	478,658	237,479	716,137	(a)	25,795	(669)
Other	2,401	474	2,875	(b)	—	—
Total	$ 1,010,775	$ 245,095	$ 1,255,870		$ 363,476	$ (669)

(a) As of December 31, 2019, the amortized cost basis of these available-for-sale investments is $691 million.
(b) Represents net pending securities sales and purchases.

	December 31, 2018					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity Securities	$ 402,008	$ 45,130	$ 447,138		$ 222,147	$ (459)
Available for Sale-Fixed Income Securities	446,978	190,378	637,356	(a)	8,634	(6,778)
Other	2,148	593	2,741	(b)	—	—
Total	$ 851,134	$ 236,101	$ 1,087,235		$ 230,781	$ (7,237)

(a) As of December 31, 2018, the amortized cost basis of these available-for-sale investments is $635 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 for the years ended December 31, 2019, 2018 and 2017 (dollars in thousands):

	Year Ended December 31,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2019			
Realized gains	$ 11,024	$ 108	$ 11,132
Realized losses	(6,972)	—	(6,972)
Proceeds from the sale of securities (a)	473,806	245,228	719,034
2018			
Realized gains	6,679	1	6,680
Realized losses	(13,552)	—	(13,552)
Proceeds from the sale of securities (a)	554,385	98,648	653,033
2017			
Realized gains	21,813	17	21,830
Realized losses	(13,146)	(9)	(13,155)
Proceeds from the sale of securities (a)	542,246	4,093	546,339

(a) Proceeds are reinvested in the nuclear decommissioning trusts or other special use funds, excluding amounts reimbursed to the Company for active union employee medical claims from the active union trust.

Fixed Income Securities Contractual Maturities

The fair value of fixed income securities, summarized by contractual maturities, at December 31, 2019 is as follows (dollars in thousands):

	Nuclear Decommissioning Trusts	Coal Reclamation Escrow Account	Active Union Medical Trust	Total
Less than one year	$ 26,984	$ 31,953	$ 40,449	$ 99,386
1 year – 5 years	136,139	25,229	138,042	299,410
5 years – 10 years	105,797	—	—	105,797
Greater than 10 years	209,738	1,806	—	211,544
Total	$ 478,658	$ 58,988	$ 178,491	$ 716,137

21. 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 for the years ended December 31, 2019 and 2018 (dollars in thousands):

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Balance December 31, 2017	$ (42,440)		$ (2,562)		$ (45,002)
OCI (loss) before reclassifications	102		(78)		24
Amounts reclassified from accumulated other comprehensive loss	4,295	(a)	1,527	(b)	5,822
Reclassification of income tax effect related to tax reform	(7,954)		(598)		(8,552)
Balance December 31, 2018	(45,997)		(1,711)		(47,708)
OCI (loss) before reclassifications	(14,041)		—		(14,041)
Amounts reclassified from accumulated other comprehensive loss	3,516	(a)	1,137	(b)	4,653
Balance December 31, 2019	$ (56,522)		$ (574)		$ (57,096)

(a) These amounts primarily represent amortization of actuarial loss, and are included in the computation of net periodic pension cost. See Note 8.
(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 17.

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 for the years ended December 31, 2019 and 2018 (dollars in thousands):

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Balance December 31, 2017	$ (24,421)		$ (2,562)		$ (26,983)
OCI (loss) before reclassifications	(326)		(78)		(404)
Amounts reclassified from accumulated other comprehensive loss	3,791	(a)	1,527	(b)	5,318
Reclassification of income tax effect related to tax reform	(4,440)		(598)		(5,038)
Balance December 31, 2018	(25,396)		(1,711)		(27,107)
OCI (loss) before reclassifications	(12,572)		—		(12,572)
Amounts reclassified from accumulated other comprehensive loss	3,020	(a)	1,137	(b)	4,157
Balance December 31, 2019	$ (34,948)		$ (574)		$ (35,522)

(a) These amounts primarily represent amortization of actuarial loss, and are included in the computation of net periodic pension cost. See Note 8.
(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 17.

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,		
	2019	2018	2017
Operating revenues	$ —	$ —	$ 119
Operating expenses	12,451	53,844	24,591
Operating loss	(12,451)	(53,844)	(24,472)
Other			
Equity in earnings of subsidiaries	562,946	569,249	507,495
Other expense	(3,957)	(3,202)	(2,422)
Total	558,989	566,047	505,073
Interest expense	15,069	12,074	5,633
Income before income taxes	531,469	500,129	474,968
Income tax benefit	(6,851)	(10,918)	(13,488)
Net income attributable to common shareholders	538,320	511,047	488,456
Other comprehensive income (loss) — attributable to common shareholders	(9,388)	5,846	(1,180)
Total comprehensive income — attributable to common shareholders	$ 528,932	$ 516,893	$ 487,276

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, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 19	$ 41
Accounts receivable	104,640	99,989
Income tax receivable	15,905	32,737
Other current assets	401	1,502
Total current assets	120,965	134,269
Investments and other assets		
Investments in subsidiaries	6,067,957	5,859,834
Deferred income taxes	40,757	5,243
Other assets	50,139	34,910
Total investments and other assets	6,158,853	5,899,987
Total Assets	$ 6,279,818	$ 6,034,256
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 7,634	$ 9,565
Accrued taxes	8,573	9,006
Common dividends payable	87,982	82,675
Short-term borrowings	114,675	76,400
Current maturities of long-term debt	450,000	—
Operating lease liabilities	81	—
Other current liabilities	15,126	19,215
Total current liabilities	684,071	196,861
Long-term debt less current maturities (Note 7)	(575)	448,796
Pension liabilities	17,942	17,766
Operating lease liabilities	1,780	—
Other	23,412	22,128
Total deferred credits and other	43,134	39,894
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
Common stock equity		
Common stock	2,650,134	2,629,440
Accumulated other comprehensive loss	(57,096)	(47,708)
Retained earnings	2,837,610	2,641,183
Total Pinnacle West Shareholders' equity	5,430,648	5,222,915
Noncontrolling interests	122,540	125,790
Total Equity	5,553,188	5,348,705
Total Liabilities and Equity	$ 6,279,818	$ 6,034,256

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,		
	2019	2018	2017
Cash flows from operating activities			
Net income	$ 538,320	$ 511,047	$ 488,456
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of subsidiaries — net	(562,946)	(569,249)	(507,495)
Depreciation and amortization	76	76	76
Deferred income taxes	(35,831)	49,535	(264)
Accounts receivable	182	(7,881)	(2,106)
Accounts payable	(2,129)	1,967	(11,162)
Accrued taxes and income tax receivables — net	16,400	(13,535)	(22,247)
Dividends received from subsidiaries	336,300	316,000	296,800
Other	(1,300)	31,807	15,092
Net cash flow provided by operating activities	289,072	319,767	257,150
Cash flows from investing activities			
Investments in subsidiaries	1,557	(142,796)	(178,027)
Repayments of loans from subsidiaries	4,190	6,477	2,987
Advances of loans to subsidiaries	(4,165)	(500)	(6,388)
Net cash flow provided by (used for) investing activities	1,582	(136,819)	(181,428)
Cash flows from financing activities			
Issuance of long-term debt	—	150,000	298,761
Short-term debt borrowings under revolving credit facility	49,000	20,000	58,000
Short-term debt repayments under revolving credit facility	(65,000)	(32,000)	(32,000)
Commercial paper - net	54,275	(7,000)	27,700
Dividends paid on common stock	(329,643)	(308,892)	(289,793)
Repayment of long-term debt	—	—	(125,000)
Common stock equity issuance - net of purchases	692	(5,055)	(13,390)
Other	—	(1)	—
Net cash flow used for financing activities	(290,676)	(182,948)	(75,722)
Net decrease in cash and cash equivalents	(22)	—	—
Cash and cash equivalents at beginning of year	41	41	41
Cash and cash equivalents at end of year	$ 19	$ 41	$ 41

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 Capital Corporation on a stand-alone basis as a holding company. Investments in subsidiaries are accounted for using the equity method.

PINNACLE WEST CAPITAL CORPORATION
SCHEDULE II — RESERVE FOR UNCOLLECTIBLES
(dollars in thousands)

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of period
Reserve for uncollectibles:					
2019	$ 4,069	$ 11,819	$ —	$ 7,717	$ 8,171
2018	2,513	10,870	—	9,314	4,069
2017	3,037	6,836	—	7,360	2,513

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE II — RESERVE FOR UNCOLLECTIBLES
(dollars in thousands)

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of period
Reserve for uncollectibles:					
2019	$ 4,069	$ 11,819	$ —	$ 7,717	$ 8,171
2018	2,513	10,870	—	9,314	4,069
2017	3,037	6,836	—	7,360	2,513

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, 2019. 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, 2019. 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 Capital Corporation and Arizona Public Service Company, 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, 2019 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.

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 20, 2020 (the "2020 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 2020 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 2020 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth information as of December 31, 2019 with respect to the 2012 Plan and 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	1,267,062	—	1,645,994
Equity compensation plans not approved by security holders		—	
Total	1,267,062	—	1,645,994

(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 2012 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 2007 Plan. However, if an award under the 2012 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 2012 Plan.

Equity Compensation Plans Approved By Security Holders

Amounts in column (a) in the table above include shares subject to awards outstanding under two 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; and (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. See Note 16 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 2020 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 2020 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	2019	2018
Audit Fees (1)	$ 2,328,565	$ 2,342,455
Audit-Related Fees (2)	322,917	300,334

(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-Q.

(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 performed in 2019 and 2018.

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 $50,000. 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 2019 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 22, 2017	3.1 to Pinnacle West/APS February 28, 2017 Form 8-K Report, File Nos. 1-8962 and 1-4473	2/28/2017
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, 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
4.2a	Pinnacle West APS	First Supplemental Indenture dated as of January 1, 1995	4.4 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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
4.3a	Pinnacle West APS	First Supplemental Indenture dated as of November 15, 1996	4.6 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
4.3b	Pinnacle West APS	Second Supplemental Indenture dated as of April 1, 1997	4.10 to APS's Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report, File No. 1-4473	4/9/1997
4.3c	Pinnacle West APS	Third Supplemental Indenture dated as of November 1, 2002	10.2 to Pinnacle West's March 31, 2003 Form 10-Q Report, File No. 1-8962	5/15/2003
4.4	Pinnacle West	Indenture dated as of December 1, 2000 between the Company and The Bank of New York, as Trustee, relating to Senior Unsecured Debt Securities	4.1 to Pinnacle West's Registration Statement No. 333-52476	12/21/2000
4.4a	Pinnacle West	Third Supplemental Indenture dated as of November 30, 2017	4.1 to Pinnacle West November 30, 2017 Form 8-K Report, File No. 1-8962	11/30/2017
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
4.6a	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
4.6b	Pinnacle West APS	Eighth Supplemental Indenture dated as of June 15, 2004	4.1 to APS's Registration Statement No. 333-106772 by means of June 24, 2004 Form 8-K Report, File No. 1-4473	6/28/2004
4.6c	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
4.6d	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
4.6e	Pinnacle West APS	Eleventh Supplemental Indenture dated as of February 26, 2009	4.6e to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6f	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
4.6g	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

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Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
4.6h	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
4.6i	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
4.6j	Pinnacle West APS	Sixteenth Supplemental Indenture dated as of January 12, 2015	4.6j to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6k	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
4.6l	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
4.6m	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
4.6n	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
4.6o	Pinnacle West APS	Twenty-First Supplemental Indenture dated as of September 11, 2017	4.1 to Pinnacle West/APS September 11, 2017 Form 8-K Report, File Nos. 1-8962 and 1-4473	9/11/2017
4.6p	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
4.6q	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
4.6r	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
4.6s	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
4.7	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
4.7a	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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
4.8a	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
10.1.1a	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
10.1.1b	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
10.1.1c	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
10.1.1d	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
10.1.1e	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
10.1.1f	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
10.1.1g	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
10.1.1h	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
10.1.1i	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
10.1.1j	Pinnacle West APS	Amendment No. 5 to the Decommissioning Trust Agreement (PVGS Unit 3), dated as of May 1, 2007	10.2 to Pinnacle West/APS March 31, 2007 Form 10-Q Report, File Nos. 1-8962 and 104473	5/9/2007

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.1.2	Pinnacle West APS	Amended and Restated Decommissioning Trust Agreement (PVGS Unit 2) dated as of January 31, 1992, among APS, Mellon Bank, N.A., as Decommissioning Trustee, and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under two separate Trust Agreements, each with a separate Equity Participant, and as Lessor under two separate Facility Leases, each relating to an undivided interest in PVGS Unit 2	10.1 to Pinnacle West's 1991 Form 10-K Report, File No. 1-8962	3/26/1992
10.1.2a	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
10.1.2b	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
10.1.2c	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
10.1.2d	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
10.1.2e	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
10.1.2f	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
10.1.2g	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
10.1.2h	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
10.2.1a[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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.2.1b[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
10.2.1c[b]	Pinnacle West APS	Fifth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective January 1, 1997	10.3A to APS's 1996 Form 10-K Report, File No. 1-4473	3/28/1997
10.2.1d[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
10.2.2a[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
10.2.2b[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
10.2.2c[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
10.2.3a[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
10.2.4a[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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.2.4b[b]	Pinnacle West APS	Second Amendment effective January 1, 2000 to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.10A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2.4c[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
10.2.4d[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
10.3.1a[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
10.3.2a[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
10.3.2b[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	Consulting Services Agreement between Pinnacle West and Donald E. Brand	10.1 to Pinnacle West/APS September 30, 2019 Form 10-Q Report, File Nos. 1-8962 and 1-4473	11/7/2019
10.4.2[b]	Pinnacle West APS	Letter Agreement dated June 17, 2008 between Pinnacle West/APS and James R. Hatfield	10.1 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/7/2008

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.4.3[b]	APS	Retention Agreement dated December 19, 2008 between APS and Robert Bement	10.4.2 to Pinnacle West/APS 2018 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/22/2019
10.4.4[b]	APS	Discretionary Credit Award Agreement dated October 20, 2014 between APS and Robert Bement	10.4.3 to Pinnacle West/APS 2018 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/22/2019
10.4.5[b]	Pinnacle West APS	Offer of Employment Letter dated July 19, 2018 between Pinnacle West and Robert E. Smith		
10.4.6[b]	Pinnacle West APS	Supplemental Agreement dated October 17, 2018 between Pinnacle West and Robert E. Smith		
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
10.5.1a[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, File Nos. 1-8962 and 1-4473	2/22/2013
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
10.6.1a[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
10.6.1b[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
10.6.1c[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
10.6.1d[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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.6.1e[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
10.6.1f[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
10.6.1g[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 2020 Variable Incentive Plan and Officer Variable Incentive Plan		
10.6.5	Pinnacle West	Description of Restricted Stock Unit Grant to Donald E. Brandt	Pinnacle West/APS December 24, 2012 Form 8-K Report, File No. 1-8962	12/26/2012
10.6.6[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
10.6.6a[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
10.6.6b[bd]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.2 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/3/2012
10.6.6c[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
10.6.6d[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
10.6.6e[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
10.6.6f[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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.6.6g[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
10.6.6h[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
10.6.6i[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
10.6.6j[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
10.6.6k[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
10.6.6l[bd]	Pinnacle West	Performance Cash Award Agreement, dated May 10, 2017, between Pinnacle West and Donald E. Brandt	10.1 to Pinnacle West/APS June 30, 2017 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/2/2017
10.6.6m[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
10.7.1a	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
10.7.1b	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
10.7.1c	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
10.7.1d	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
10.7.2a	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
10.7.3a	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
10.8.1	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
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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.9.1a	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
10.9.1b	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
10.9.1c	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
10.9.1d	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
10.10.2a	Pinnacle West APS	Amendment No. 1 dated April 5, 1995 to the Long-Term Power Transaction Agreement and Asset Purchase and Power Exchange Agreement between PacifiCorp and APS	10.3 to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996
10.10.3	Pinnacle West APS	Restated Transmission Agreement between PacifiCorp and APS dated April 5, 1995	10.4 to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
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	Term Loan Agreement dated as of December 21, 2018 among Pinnacle West, as Borrower, KeyBank National Association, as Agent, PNC Bank, National Association and Wells Fargo Bank, National Association, as Co-Syndication Agents and such institutions compromising the lenders party thereto	10.4.2 to Pinnacle West/APS 2018 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/22/2019
10.11.2	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 compromising 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
10.11.3	Pinnacle West	Five-Year Credit Agreement dated as of July 12, 2018, among Pinnacle West, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto	10.3 to Pinnacle West/APS June 30, 2018 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/3/2018
10.11.4	Pinnacle West	364-Day Term Loan, dated as of May 9, 2019, among Pinnacle West, as Borrower, PNC Bank, National Association, as Agent and Citibank, as Syndication Agent	10.1 to Pinnacle West/APS June 30, 2019 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/8/2019
10.11.5	Pinnacle West APS	Five-Year Credit Agreement dated as of June 29, 2017 among APS, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto	10.2 to Pinnacle West/APS June 30, 2017 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/3/2017
10.11.5a	Pinnacle West APS	Amendment No. 1, dated July 13, 2018, to Five-Year Credit Agreement dated as of June 29, 2017, among APS, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto	10.11.4a to Pinnacle West/APS June 30, 2018 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/3/2018

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.11.6	Pinnacle West APS	Five-Year Credit Agreement dated as of July 12, 2018 among APS, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto	10.4 to Pinnacle West/APS June 30, 2018 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/3/2018
10.12.1[c]	Pinnacle West APS	Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	4.3 to APS's Form 18 Registration Statement, File No. 33-9480	10/24/1986
10.12.1a[c]	Pinnacle West APS	Amendment No. 1, dated as of November 1, 1986, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.5 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8, File No. 1-4473	12/4/1986
10.12.1b[c]	Pinnacle West APS	Amendment No. 2 dated as of June 1, 1987 to Facility Lease dated as of August 1, 1986 between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS's 1988 Form 10-K Report, File No. 1-4473	3/8/1989
10.12.1c[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
10.12.1d[c]	Pinnacle West APS	Amendment No. 4, dated as of September 30, 2015, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under a Trust Agreement with Emerson Finance LLC, as Lessor, and APS, as Lessee	10.2 to Pinnacle West/APS September 30, 2015 Form 10-Q Report, File Nos. 1-8962 and 1-4473	10/30/2015

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.12.1e[c]	Pinnacle West APS	Amendment No. 3, dated as of September 30, 2015, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under a Trust Agreement with Security Pacific Capital Leasing Corporation, as Lessor, and APS, as Lessee	10.3 to Pinnacle West/APS September 30, 2015 Form 10-Q Report, File Nos. 1-8962 and 1-4473	10/30/2015
10.12.2	Pinnacle West APS	Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.1 to APS's November 18, 1986 Form 8-K Report, File No. 1-4473	1/20/1987
10.12.2a	Pinnacle West APS	Amendment No. 1, dated as of August 1, 1987, to Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	4.13 to APS's Form 18 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report, File No. 1-4473	8/24/1987
10.12.2b	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
10.12.2c	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
10.13.1	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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
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
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
10.15.3a	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		

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
31.2	Pinnacle West	Certificate of Theodore N. Geisler, 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 Theodore N. Geisler, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended		
32.1[e]	Pinnacle West	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		
32.2[e]	APS	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		
99.1	Pinnacle West APS	Collateral Trust Indenture among PVGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee	4.2 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.1a	Pinnacle West APS	Supplemental Indenture to Collateral Trust Indenture among PVGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee	4.3 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.2[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
99.2a[c]	Pinnacle West APS	Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1, 1986, among PVGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	10.8 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1, on December 3, 1986 Form 8, File No. 1-4473	12/4/1986

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
99.2b[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
99.3[c]	Pinnacle West APS	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to APS's Form 18 Registration Statement, File No. 33-9480	10/24/1986
99.3a[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
99.3b[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
99.4[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
99.4a[c]	Pinnacle West APS	Amendment No. 1, dated as of November 1, 1986, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.10 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. l on December 3, 1986 Form 8, File No. 1-4473	12/4/1986

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
99.4b[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
99.5	Pinnacle West APS	Participation Agreement, dated as of December 15, 1986, among PVGS Funding Report Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee under a Trust Indenture, APS, and the Owner Participant named therein	28.2 to APS's September 30, 1992 Form 10-Q Report, File No. 1-4473	11/9/1992
99.5a	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
99.5b	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
99.6	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
99.6a	Pinnacle West APS	Supplemental Indenture No. 1, dated as of August 1, 1987, to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.13 to APS's Form 18 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report, File No. 1-4473	8/24/1987

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
99.6b	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
99.7	Pinnacle West APS	Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.5 to APS's November 18, 1986 Form 8-K Report, File No. 1-4473	1/20/1987
99.7a	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
99.8[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
99.9	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
99.10	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
99.11	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		

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

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

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

[d] Additional agreements, substantially identical in all material respects to this Exhibit have been entered into with additional persons. Although such additional documents may differ in other respects (such as dollar amounts and dates of execution), there are no material details in which such agreements differ from this Exhibit.

[e] Furnished herewith as an Exhibit.

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 21, 2020

/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 Theodore N. Geisler and Robert E. Smith, and each of them, our true and lawful attorneys with full power to them and each of them to sign for us, and in our names in the capacities indicated below, any and all amendments to this Annual Report on Form 10-K filed with the Securities and Exchange Commission.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Jeffrey B. Guldner (Jeffrey B. Guldner, Chairman of the Board of Directors, President and Chief Executive Officer)	Principal Executive Officer and Director	February 21, 2020
/s/ Theodore N. Geisler (Theodore N. Geisler, Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 21, 2020
/s/ Elizabeth A. Blankenship (Elizabeth A. Blankenship, Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 21, 2020

/s/ Denis A. Cortese, M.D. (Denis A. Cortese, M.D.)	Director	February 21, 2020
/s/ Richard P. Fox (Richard P. Fox)	Director	February 21, 2020
/s/ Michael L. Gallagher (Michael L. Gallagher)	Director	February 21, 2020
/s/ Dale E. Klein, Ph.D. (Dale E. Klein, Ph.D.)	Director	February 21, 2020
/s/ Humberto S. Lopez (Humberto S. Lopez)	Director	February 21, 2020
/s/ Kathryn L. Munro (Kathryn L. Munro)	Director	February 21, 2020
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	February 21, 2020
/s/ Paula J. Sims (Paula J. Sims)	Director	February 21, 2020
/s/ James E. Trevathan (James E. Trevathan)	Director	February 21, 2020
/s/ David P. Wagener (David P. Wagener)	Director	February 21, 2020

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 21, 2020

/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 Theodore N. Geisler and Robert E. Smith, and each of them, our true and lawful attorneys with full power to them and each of them to sign for us, and in our names in the capacities indicated below, any and all amendments to this Annual Report on Form 10-K filed with the Securities and Exchange Commission.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Jeffrey B. Guldner (Jeffrey B. Guldner, Chairman of the Board of Directors and Chief Executive Officer)	Principal Executive Officer and Director	February 21, 2020
/s/ Theodore N. Geisler (Theodore N. Geisler, Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 21, 2020
/s/ Elizabeth A. Blankenship (Elizabeth A. Blankenship Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 21, 2020

/s/ Denis A. Cortese, M.D. (Denis A. Cortese, M.D.)	Director	February 21, 2020
/s/ Richard P. Fox (Richard P. Fox)	Director	February 21, 2020
/s/ Michael L. Gallagher (Michael L. Gallagher)	Director	February 21, 2020
/s/ Dale E. Klein, Ph.D. (Dale E. Klein, Ph.D.)	Director	February 21, 2020
/s/ Humberto S. Lopez (Humberto S. Lopez)	Director	February 21, 2020
/s/ Kathryn L. Munro (Kathryn L. Munro)	Director	February 21, 2020
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	February 21, 2020
/s/ Paula J. Sims (Paula J. Sims)	Director	February 21, 2020
/s/ James E. Trevathan (James E. Trevathan)	Director	February 21, 2020
/s/ David P. Wagener (David P. Wagener)	Director	February 21, 2020

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;

- 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 33 1/3%; (ii) at least 33 1/3% 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.

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 Executive Vice
President,
Public Policy & General Counsel

July 19, 2018

Mr. Robert E. Smith 2512 W. Beach Blvd. Gulf Shores, AL 36542

Dear Bob,

I am delighted to extend to you this offer to become the Senior Vice President and General Counsel of both Pinnacle West Capital Corporation and Arizona Public Service Company. The details of our proposal are included in Attachment A.

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

Bob, 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 we can to ensure a smooth transition for you and Wendy. I look forward to your contributions to our organization.

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

Sincerely,

/s/ Jeffrey B. Guldner

Jeffrey B. Guldner

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

Acceptance: /s/ Robert E. Smith   Date: July 19, 2018

Attachment A

- Proposed start date of August 13, 2018
- A starting annual base salary of $500,000.
- Guaranteed 2019 base salary increase of $50,000 effective January 1, 2019.
- Initial hiring incentive of $150,000 payable during the first two weeks of your employment. Second year hiring incentive of $150,000 payable within two weeks of your 1 year anniversary date.
- 4 weeks 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 a target payment for 2018 of 65% and up to a maximum of 130% 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 2018 will be prorated based on the amount of time employed during 2018 .
- Long-Term Stock Based Compensation: Subject to Human Resources Committee approval at the October 2018 meeting, a long-term stock based award to be granted to you effective upon your hire date with a $750,000 grant date value. (Number of shares noted below is based on $80 per share stock price and is subject to change based on stock price on date of hire).

  (1) An award of 3,750 performance shares
    - 1,250 shares will be released in 2020
    - 2,500 shares will be released in 2021

  (2) An award of 5,625 restricted stock units
    - 1,250 units will vest on 2/20/2019
    - 1,875 units will vest on 2/20/2020
    - 2,500 units will vest on 2/20/2021

  The 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.

- An expected annual long-term stock based award will be granted in February 2019 with a grant date fair value of $550,000, subject to the normal approval process by the Human Resources Committee.

- 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 follows:

Percent of Monthly	Compensation Contribution
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 percent 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.

- You will receive a Key Executive Employment & Severance Agreement that provides severance benefits in connection with a change of control. 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 on your one-month anniversary date of employment. Medical and dental plan premiums are on a pre-tax basis.

- You will be eligible for the relocation benefits provided generally to the Company's senior executives.

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 or 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.

SUPPLEMENTAL AGREEMENT BETWEEN
PINNACLE WEST CAPTIAL CORPORATION AND ROBERT E. SMITH

This Supplemental Agreement (the "**Agreement**") is entered into by and between Pinnacle West Capital Corporation (the "**Company**") and Robert E. Smith ("**Executive**").

1. **Background**. The Company previously entered into an Offer of Employment Letter, dated July 19, 2018, with Executive (the "Offer Letter") and the purpose of this Agreement is to provide additional supplemental benefits to Executive as described below.

2. **Effective Date**. This Agreement shall be effective October 17, 2018.

3. **Salary Increases**. As of the Effective Date, Executive's base salary shall be increased to $550,000.

4. **Equity Awards**. In addition to the Executive's previously expected annual long-term stock based award to be granted in February 2019 of $550,000 as set forth in the Offer Letter, the annual long-term stock based award that is expected to be granted by the Company to the Executive under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan in February 2019 shall have an additional grant date fair value of $100,000 for a total annual long-term stock based award with a grant date fair value of $650,000, subject to the normal approval process by the Human Resources Committee of the Company's Board of Directors.

5. **Impact on Offer Letter**. This Agreement supplements the Offer Letter which otherwise remains in full force and effect.

IN WITNESS WHEREOF, the Company and Executive have caused this Agreement to be executed as of the date set forth below.

PINNACLE WEST CAPTIAL CORPORATION

By: /s/ Donald E. Brandt
Its: Chief Executive Officer

October 28, 2018
Date

EXECUTIVE

/s/ Robert E. Smith
Robert E. Smith

October 25, 2019
Date

Exhibit 10.6.4

Summary of 2020 Incentive Plans

On December 17, 2019, the Human Resources Committee (the “Committee”) of the Pinnacle West Capital Corporation (“Pinnacle West”) Board of Directors (the “Board”) approved the portion of the APS 2020 Annual Incentive Award Plan (the “APS Plan”) that provides an incentive award opportunity for Jeffrey B. Guldner, the Chairman of the Board, President, and Chief Executive Officer of Pinnacle West and Arizona Public Service Company ("APS"). On December 18, 2019, the Board, acting on the recommendation of the Committee, approved the portion of the APS Plan that includes an incentive award opportunity for James R. Hatfield, Executive Vice President and Chief Financial Officer of Pinnacle West and APS and Daniel T. Froetscher, Executive Vice President, Operations of APS and the APS 2020 Annual Incentive Award Plan for Palo Verde Employees (the “Palo Verde Plan”), which includes an incentive award opportunity for Robert S. Bement, Executive Vice President and Chief Nuclear Officer of 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. Hatfield and Froetscher, each achieves a specified threshold earnings level. The award opportunities for Mr. Guldner under the APS Plan are based on the achievement of specified 2020 Pinnacle West earnings levels and specified business unit performance goals. Mr. Guldner has a target award opportunity of up to 110% of his base salary. Mr. Guldner may earn less or more than the target amount, up to a maximum award opportunity of 220% 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 in the functional areas of customer service, transmission and distribution, fossil generation, corporate resources and performance of the Palo Verde Generating Station.

The award opportunities for Messrs. Hatfield and Froetscher under the APS Plan are based on the achievement of specified 2020 APS earnings levels and specified business unit performance goals. Mr. Hatfield has a target award opportunity of up to 75% of his base salary and Mr. Froetscher has a target award opportunity of up to 90% of his base salary. Messrs. Hatfield and Froetscher may earn less or more than the target amount, up to a maximum award opportunity of 150% of base salary for Mr. Hatfield and 180% for Mr. Froetscher, 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. Hatfield and Froetscher are derived from the APS critical areas of focus, as provided in its “Core” strategic framework, in the functional areas of employees, operational excellence, and shareholder value.

The award opportunity for Mr. Bement under the Palo Verde Plan is based on the achievement of specified 2020 APS earnings levels and specified business unit performance goals. No incentive payment will be awarded to Mr. Bement under the APS earnings portion of the Palo Verde Plan unless Palo Verde achieves specified business unit performance goals and APS achieves a target threshold earnings level. The business unit performance indicators for Mr. Bement under the Palo Verde Plan are in the functional areas of employees, operational excellence, performance improvement and shareholder value. Mr. Bement has a target of 75% of his base salary, and up to a maximum of 150% of his base salary, depending on the achievement of the earnings and business unit performance goals, separately or in combination, and before adjustment for individual performance. Effective on January 21, 2020 when Mr. Bement transitions to Executive Vice President and Special Advisor to the Chief Executive Officer of APS, Mr. Bement will remain under the Palo Verde Plan with a target of 75% of his base salary. Due to Mr. Bement’s retirement, he will receive a prorated award under the Palo Verde Plan based on the amount of time he was actively employed during the plan year.

The Committee may adjust targets or incentive results under the APS Plan and Palo Verde 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 Arizona Corporation Commission rate-related impacts on earnings. Any awards for Messrs. Guldner, Hatfield, Froetscher and Bement are subject to potential forfeiture or recovery in accordance with Pinnacle West's Clawback Policy.

Exhibit 21.1

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.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-224366 and 333-218886 on Form S-3 and Registration Statement Nos. 333-143432, 333-182427, and 333-157151 on Form S-8 of our report dated February 21, 2020, relating to the consolidated financial statements and financial statement schedules of Pinnacle West Capital Corporation and subsidiaries, and the effectiveness of Pinnacle West Capital Corporation and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K for the year ended December 31, 2019.

/s/ Deloitte & Touche LLP

Phoenix, Arizona
February 21, 2020

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-224366-01 on Form S-3 and Registration Statement Nos. 333-46161 and 333-158774 on Form S-8 of our report dated February 21, 2020, relating to the consolidated financial statements and financial statement schedule of Arizona Public Service Company and subsidiaries, and the effectiveness of Arizona Public Service Company and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K for the year ended December 31, 2019.

/s/ Deloitte & Touche LLP

Phoenix, Arizona
February 21, 2020

Exhibit 31.1

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 21, 2020

/s/ Jeffrey B. Guldner

Jeffrey B. Guldner
Chairman of the Bord of Directors, President and
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Theodore N. Geisler, 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 21, 2020

/s/ Theodore N. Geisler

Theodore N. Geisler
Senior Vice President and Chief Financial Officer

Exhibit 31.3

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 21, 2020

/s/ Jeffrey B. Guldner

Jeffrey B. Guldner
Chairman of the Board of Directors and
Chief Executive Officer

Exhibit 31.4

CERTIFICATION

I, Theodore N. Geisler, 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 21, 2020

/s/ Theodore N. Geisler

Theodore N. Geisler
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, 2019 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 21, 2020

/s/ Jeffrey B. Guldner

Jeffrey B. Guldner
Chairman of the Board of the Directors, President and Chief Executive Officer

I, Theodore N. Geisler, 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, 2019 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 21, 2020

/s/ Theodore N. Geisler

Theodore N. Geisler
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, 2019 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 21, 2020

/s/ Jeffrey B. Guldner

Jeffrey B. Guldner
Chairman of the Board of Directors and
Chief Executive Officer

I, Theodore N. Geisler, 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, 2019 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 21, 2020

/s/ Theodore N. Geisler

Theodore N. Geisler
Senior Vice President and Chief Financial Officer