UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2022

OR

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

For the transition period from to

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

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock	PNW	The New York Stock Exchange

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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit 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	☒

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 April 28, 2022:	113,001,085
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of April 28, 2022:	71,264,947

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

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This combined Form 10-Q is separately provided by Pinnacle West Capital Corporation ("Pinnacle West") and Arizona Public Service Company ("APS"). Any use of the words "Company," "we," and "our" refer to Pinnacle West. Each registrant is providing on its own behalf all of the information contained in this Form 10-Q that relates to such registrant and, where required, its subsidiaries. Except as stated in the preceding sentence, neither registrant is providing 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 1 of this report includes Condensed Consolidated Financial Statements of Pinnacle West and Condensed Consolidated Financial Statements of APS. Item 1 also includes Combined Notes to Condensed Consolidated Financial Statements.

FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as “estimate,” “predict,” “may,” “believe,” “plan,” “expect,” “require,” “intend,” “assume,” “project,” “anticipate,” “goal,” “seek,” “strategy,” “likely,” “should,” “will,” “could,” and similar words. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from outcomes currently expected or sought by Pinnacle West or APS. In addition to the Risk Factors described in Part I, Item 1A of the Pinnacle West/APS Annual Report on Form 10-K for the fiscal year ended December 31, 2021 (“2021 Form 10-K”), Part II, Item 1A of this report and in Part I, Item 2 — “Management’s Discussion and Analysis of Financial Condition and Results of Operations” of this report, these factors include, but are not limited to:

- the potential effects of the continued Coronavirus (“COVID-19”) pandemic, including, but not limited to, demand for energy, economic growth, our employees and contractors, vaccine mandates, supply chain, expenses, inflation, capital markets, capital projects, operations and maintenance activities, uncollectable accounts, liquidity, cash flows or other unpredictable events;
- our ability to manage capital expenditures and operations and maintenance costs while maintaining reliability and customer service levels;
- variations in demand for electricity, including those due to weather, seasonality (including large increases in ambient temperatures), the general economy or social conditions, customer and sales growth (or decline), the effects of energy conservation measures and distributed generation, and technological advancements;
- the potential effects of climate change on our electric system, including as a result of weather extremes such as prolonged drought and high temperature variations in the area where APS conducts its business;
- power plant and transmission system performance and outages;
- competition in retail and wholesale power markets;
- regulatory and judicial decisions, developments, and proceedings;
- new legislation, ballot initiatives and regulation or interpretations of existing legislation or regulations, including those relating to environmental requirements, regulatory and energy policy, nuclear plant operations and potential deregulation of retail electric markets;
- fuel and water supply availability;
- our ability to achieve timely and adequate rate recovery of our costs through our rates and adjustor recovery mechanisms, including returns on and of debt and equity capital investment;
- our ability to meet renewable energy and energy efficiency mandates and recover related costs;
- the ability of APS to achieve its clean energy goals (including a goal by 2050 of 100% clean, carbon-free electricity) and, if these goals are achieved, the impact of such achievement on APS, its customers, and its business, financial condition, and results of operations;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- current and future economic conditions in Arizona, including in real estate markets;
- the direct or indirect effect on our facilities or business from cybersecurity threats or intrusions, data security breaches, war, acts of war, international sanctions, terrorist attack, physical attack, severe storms, or other catastrophic events, such as fires, explosions, pandemic health events, or similar occurrences;
- the development of new technologies which may affect electric sales or delivery;
- the cost of debt and equity capital and the ability to access capital markets when required;
- general economic conditions, including inflation rates, monetary fluctuations, and supply chain constraints;
- 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 landowners to meet contractual or other obligations or extend the rights for continued power plant operations; and
- restrictions on dividends or other provisions in our credit agreements and Arizona Corporation Commission ("ACC") orders.

These and other factors are discussed in the Risk Factors described in Part I, Item 1A of our 2021 Form 10-K, Part II, Item 1A of this report, and in Part I, Item 2 — "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 — FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

INDEX TO FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

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

	Three Months Ended March 31,	
	2022	**2021**
OPERATING REVENUES (NOTE 2)	$ 783,531	$ 696,475
OPERATING EXPENSES		
Fuel and purchased power	265,269	198,227
Operations and maintenance	218,342	230,055
Depreciation and amortization	186,605	157,820
Taxes other than income taxes	57,998	59,483
Other expenses	825	3,356
Total	729,039	648,941
OPERATING INCOME	54,492	47,534
OTHER INCOME (DEDUCTIONS)		
Allowance for equity funds used during construction	9,747	9,207
Pension and other postretirement non-service credits - net	23,809	27,791
Other income (Note 9)	1,704	12,429
Other expense (Note 9)	(3,422)	(3,853)
Total	31,838	45,574
INTEREST EXPENSE		
Interest charges	65,389	61,938
Allowance for borrowed funds used during construction	(4,482)	(4,994)
Total	60,907	56,944
INCOME BEFORE INCOME TAXES	25,423	36,164
INCOME TAXES	4,161	(4,350)
NET INCOME	21,262	40,514
Less: Net income attributable to noncontrolling interests (Note 6)	4,306	4,873
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 16,956	$ 35,641
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING - BASIC	113,102	112,829
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING -DILUTED	113,295	113,093
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING		
Net income attributable to common shareholders - basic	$ 0.15	$ 0.32
Net income attributable to common shareholders - diluted	$ 0.15	$ 0.32

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

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

	Three Months Ended March 31,	
	2022	2021
NET INCOME	$ 21,262	$ 40,514
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Derivative instruments net unrealized gain, net of tax expense of $83 and $86	252	262
Pension and other postretirement benefit activity, net of tax expense $296 and $336	901	1,022
Total other comprehensive income	1,153	1,284
COMPREHENSIVE INCOME	22,415	41,798
Less: Comprehensive income attributable to noncontrolling interests	4,306	4,873
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 18,109	$ 36,925

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

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

	March 31, 2022	December 31, 2021
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 13,968	$ 9,969
Customer and other receivables	324,659	391,923
Accrued unbilled revenues	132,765	133,980
Allowance for doubtful accounts (Note 2)	(24,666)	(25,354)
Materials and supplies (at average cost)	358,287	349,135
Income tax receivable	6,972	7,514
Fossil fuel (at average cost)	20,772	18,032
Assets from risk management activities (Note 7)	206,102	63,481
Deferred fuel and purchased power regulatory asset (Note 4)	354,816	388,148
Other regulatory assets (Note 4)	131,444	130,376
Other current assets	69,474	83,896
Total current assets	1,594,593	1,551,100
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 11 and 12)	1,227,465	1,294,757
Other special use funds (Notes 11 and 12)	349,042	358,410
Assets from risk management activities (Note 7)	91,521	46,908
Other assets	105,605	97,884
Total investments and other assets	1,773,633	1,797,959
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	21,844,618	21,688,661
Accumulated depreciation and amortization	(7,597,037)	(7,504,603)
Net	14,247,581	14,184,058
Construction work in progress	1,418,308	1,329,478
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	93,199	94,166
Intangible assets, net of accumulated amortization	269,802	273,693
Nuclear fuel, net of accumulated amortization	119,296	106,039
Total property, plant and equipment	16,148,186	15,987,434
DEFERRED DEBITS		
Regulatory assets (Note 4)	1,184,246	1,192,987
Operating lease right-of-use assets	896,907	890,057
Assets for pension and other postretirement benefits (Note 5)	563,019	545,723
Other	40,370	37,962
Total deferred debits	2,684,542	2,666,729
TOTAL ASSETS	$ 22,200,954	$ 22,003,222

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

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

	March 31, 2022	December 31, 2021
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 343,255	$ 393,083
Accrued taxes	222,492	168,645
Accrued interest	61,648	57,332
Common dividends payable	—	95,988
Short-term borrowings (Note 3)	262,950	292,000
Current maturities of long-term debt (Note 3)	—	150,000
Customer deposits	41,628	42,293
Liabilities from risk management activities (Note 7)	1,706	4,373
Liabilities for asset retirements	4,069	4,473
Operating lease liabilities	100,949	100,443
Regulatory liabilities (Note 4)	448,778	296,271
Other current liabilities	109,255	151,968
Total current liabilities	1,596,730	1,756,869
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 3)	7,226,624	6,913,735
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,318,959	2,311,862
Regulatory liabilities (Note 4)	2,438,672	2,499,213
Liabilities for asset retirements	771,720	762,909
Liabilities for pension benefits (Note 5)	149,856	152,865
Customer advances	314,664	257,151
Coal mine reclamation	175,776	174,616
Deferred investment tax credit	186,251	186,570
Unrecognized tax benefits	4,758	4,657
Operating lease liabilities	735,718	728,401
Other	231,090	232,914
Total deferred credits and other	7,327,464	7,311,158
COMMITMENTS AND CONTINGENCIES (NOTE 8)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 113,047,699 and 113,014,528 issued at respective dates	2,706,325	2,702,743
Treasury stock at cost; 50,921 and 87,608 shares at respective dates	(3,648)	(6,401)
Total common stock	2,702,677	2,696,342
Retained earnings	3,281,601	3,264,719
Accumulated other comprehensive loss	(53,708)	(54,861)
Total shareholders' equity	5,930,570	5,906,200
Noncontrolling interests (Note 6)	119,566	115,260
Total equity	6,050,136	6,021,460
TOTAL LIABILITIES AND EQUITY	$ 22,200,954	$ 22,003,222

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

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

	Three Months Ended March 31,	
	2022	2021
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 21,262	$ 40,514
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	203,639	176,409
Deferred fuel and purchased power	(6,110)	(52,210)
Deferred fuel and purchased power amortization	39,442	(564)
Allowance for equity funds used during construction	(9,747)	(9,207)
Deferred income taxes	3,835	(11,077)
Deferred investment tax credit	(319)	(529)
Stock compensation	5,338	11,337
Changes in current assets and liabilities:		
Customer and other receivables	66,146	50,545
Accrued unbilled revenues	1,215	10,163
Materials, supplies and fossil fuel	(11,892)	(4,801)
Income tax receivable	542	6,792
Other current assets	13,347	(9,042)
Accounts payable	(13,873)	24,465
Accrued taxes	53,847	53,985
Other current liabilities	(40,211)	(46,028)
Change in margin and collateral accounts — assets	8,600	—
Change in other long-term assets	52,153	(39,667)
Change in operating lease assets	324	2,890
Change in other long-term liabilities	(47,883)	(513)
Change in operating lease liabilities	953	(1,450)
Net cash provided by operating activities	340,608	202,012
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(391,583)	(363,775)
Contributions in aid of construction	28,262	15,296
Allowance for borrowed funds used during construction	(4,422)	(4,994)
Proceeds from nuclear decommissioning trusts sales and other special use funds	361,754	379,978
Investment in nuclear decommissioning trusts and other special use funds	(361,809)	(380,548)
Other	(6,543)	5,974
Net cash used for investing activities	(374,341)	(348,069)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	312,052	150,000
Short-term borrowing and (repayments) - net	(29,050)	49,750
Short-term debt repayments under revolving credit facility	—	(4,000)
Dividends paid on common stock	(94,265)	(91,721)
Repayment of long-term debt	(150,000)	—
Common stock equity issuances and (purchases) - net	(1,005)	(738)
Net cash provided by financing activities	37,732	103,291
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	3,999	(42,766)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	9,969	59,968
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 13,968	$ 17,202

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

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(unaudited)
(dollars in thousands)

Three Months Ended March 31, 2022

	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, January 1, 2022	113,014,528	$ 2,702,743	(87,608)	$ (6,401)	$ 3,264,719	$ (54,861)	$ 115,260	$ 6,021,460
Net income		—		—	16,956	—	4,306	21,262
Other comprehensive income		—		—	—	1,153	—	1,153
Dividends on common stock		—		—	(74)	—	—	(74)
Issuance of common stock	33,171	3,582		—	—	—	—	3,582
Purchase of treasury stock (a)		—	(24,885)	(1,665)	—	—	—	(1,665)
Reissuance of treasury stock for stock-based compensation and other		—	61,572	4,418	—	—	—	4,418
Balance, March 31, 2022	113,047,699	$ 2,706,325	(50,921)	$ (3,648)	$ 3,281,601	$ (53,708)	$ 119,566	$ 6,050,136

Three Months Ended March 31, 2021

	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, January 1, 2021	112,760,051	$ 2,677,482	(72,006)	$ (6,289)	$ 3,025,106	$ (62,796)	$ 119,290	$ 5,752,793
Net income		—		—	35,641	—	4,873	40,514
Other comprehensive income		—		—	—	1,284	—	1,284
Dividends on common stock		—		—	5	—	—	5
Issuance of common stock	31,514	9,570		—	—	—	—	9,570
Purchase of treasury stock (a)		—	(17,437)	(1,333)	—	—	—	(1,333)
Reissuance of treasury stock for stock-based compensation and other		—	45,105	3,846	—	—	—	3,846
Other		—		—	—	—	1	1
Balance, March 31, 2021	112,791,565	$ 2,687,052	(44,338)	$ (3,776)	$ 3,060,752	$ (61,512)	$ 124,164	$ 5,806,680

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

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

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

	Three Months Ended March 31,	
	2022	2021
OPERATING REVENUES (NOTE 2)	$ 783,531	$ 696,475
OPERATING EXPENSES		
Fuel and purchased power	265,269	198,227
Operations and maintenance	214,601	226,401
Depreciation and amortization	186,583	157,800
Taxes other than income taxes	57,959	59,472
Other expenses	825	3,356
Total	725,237	645,256
OPERATING INCOME	58,294	51,219
OTHER INCOME (DEDUCTIONS)		
Allowance for equity funds used during construction	9,747	9,207
Pension and other postretirement non-service credits - net	23,907	27,837
Other income (Note 9)	1,152	11,960
Other expense (Note 9)	(1,849)	(3,350)
Total	32,957	45,654
INTEREST EXPENSE		
Interest charges	62,309	59,388
Allowance for borrowed funds used during construction	(4,422)	(4,994)
Total	57,887	54,394
INCOME BEFORE INCOME TAXES	33,364	42,479
INCOME TAXES	4,859	2,319
NET INCOME	28,505	40,160
Less: Net income attributable to noncontrolling interests (Note 6)	4,306	4,873
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 24,199	$ 35,287

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

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

	Three Months Ended March 31,	
	2022	2021
NET INCOME	$ 28,505	$ 40,160
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Pension and other postretirement benefits activity, net of tax expense $269 and $305	820	927
Total other comprehensive income	820	927
COMPREHENSIVE INCOME	29,325	41,087
Less: Comprehensive income attributable to noncontrolling interests	4,306	4,873
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 25,019	$ 36,214

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

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

	March 31, 2022	December 31, 2021
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	$ 21,841,156	$ 21,685,200
Accumulated depreciation and amortization	(7,593,747)	(7,501,317)
Net	14,247,409	14,183,883
Construction work in progress	1,404,913	1,327,721
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	93,199	94,166
Intangible assets, net of accumulated amortization	269,647	273,537
Nuclear fuel, net of accumulated amortization	119,296	106,039
Total property, plant and equipment	16,134,464	15,985,346
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 11 and 12)	1,227,465	1,294,757
Other special use funds (Notes 11 and 12)	349,042	358,410
Assets from risk management activities (Note 7)	91,521	46,908
Other assets	43,661	42,440
Total investments and other assets	1,711,689	1,742,515
CURRENT ASSETS		
Cash and cash equivalents	12,120	9,374
Customer and other receivables	323,679	390,533
Accrued unbilled revenues	132,765	133,980
Allowance for doubtful accounts (Note 2)	(24,666)	(25,354)
Materials and supplies (at average cost)	358,287	349,135
Fossil fuel (at average cost)	20,772	18,032
Income tax receivable	5,549	10,756
Assets from risk management activities (Note 7)	206,102	63,481
Deferred fuel and purchased power regulatory asset (Note 4)	354,816	388,148
Other regulatory assets (Note 4)	131,444	130,376
Other current assets	51,392	57,729
Total current assets	1,572,260	1,526,190
DEFERRED DEBITS		
Regulatory assets (Note 4)	1,184,246	1,192,987
Operating lease right-of-use assets	891,533	888,207
Assets for pension and other postretirement benefits (Note 5)	554,250	537,092
Other	38,095	37,319
Total deferred debits	2,668,124	2,655,605
TOTAL ASSETS	$ 22,086,537	$ 21,909,656

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

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

	March 31, 2022	December 31, 2021
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	3,171,696	3,021,696
Retained earnings	3,494,432	3,470,235
Accumulated other comprehensive loss	(34,060)	(34,880)
Total shareholder equity	6,810,230	6,635,213
Noncontrolling interests (Note 6)	119,566	115,260
Total equity	6,929,796	6,750,473
Long-term debt less current maturities (Note 3)	6,267,482	6,266,693
Total capitalization	13,197,278	13,017,166
CURRENT LIABILITIES		
Short-term borrowings (Note 3)	250,000	278,700
Accounts payable	329,412	389,365
Accrued taxes	209,730	152,012
Accrued interest	59,293	56,622
Common dividends payable	—	96,000
Customer deposits	41,628	42,293
Liabilities from risk management activities (Note 7)	1,706	4,373
Liabilities for asset retirements	4,069	4,473
Operating lease liabilities	100,629	100,199
Regulatory liabilities (Note 4)	448,778	296,271
Other current liabilities	106,861	145,286
Total current liabilities	1,552,106	1,565,594
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,334,749	2,331,701
Regulatory liabilities (Note 4)	2,438,672	2,499,213
Liabilities for asset retirements	771,720	762,909
Liabilities for pension benefits (Note 5)	135,867	138,328
Customer advances	314,664	257,151
Coal mine reclamation	175,776	174,616
Deferred investment tax credit	186,251	186,570
Unrecognized tax benefits	37,524	37,423
Operating lease liabilities	730,434	726,572
Other	211,496	212,413
Total deferred credits and other	7,337,153	7,326,896
COMMITMENTS AND CONTINGENCIES (NOTE 8)		
TOTAL LIABILITIES AND EQUITY	$ 22,086,537	$ 21,909,656

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

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

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 28,505	$ 40,160
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	203,617	176,389
Deferred fuel and purchased power	(6,110)	(52,210)
Deferred fuel and purchased power amortization	39,442	(564)
Allowance for equity funds used during construction	(9,747)	(9,207)
Deferred income taxes	(106)	(2,616)
Deferred investment tax credit	(319)	(529)
Changes in current assets and liabilities:		
Customer and other receivables	65,736	50,103
Accrued unbilled revenues	1,215	10,163
Materials, supplies and fossil fuel	(11,892)	(4,801)
Income tax receivable	5,207	—
Other current assets	5,261	(8,825)
Accounts payable	(17,074)	23,881
Accrued taxes	57,718	62,204
Other current liabilities	(37,579)	(43,917)
Change in margin and collateral accounts — assets	8,600	—
Change in other long-term assets	53,827	(39,491)
Change in operating lease assets	254	2,865
Change in other long-term liabilities	(46,790)	782
Change in operating lease liabilities	1,027	(1,424)
Net cash provided by operating activities	340,792	202,963
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(386,873)	(363,775)
Contributions in aid of construction	28,262	15,296
Allowance for borrowed funds used during construction	(4,422)	(4,994)
Proceeds from nuclear decommissioning trusts sales and other special use funds	361,754	379,978
Investment in nuclear decommissioning trusts and other special use funds	(361,809)	(380,548)
Other	(258)	2,306
Net cash used for investing activities	(363,346)	(351,737)
CASH FLOWS FROM FINANCING ACTIVITIES		
Short-term borrowings and (repayments) - net	(28,700)	199,500
Equity infusion	150,000	—
Dividends paid on common stock	(96,000)	(93,500)
Net cash provided by financing activities	25,300	106,000
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2,746	(42,774)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	9,374	57,310
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 12,120	$ 14,536

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

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

	Three Months Ended March 31, 2022						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, January 1, 2022	71,264,947	$ 178,162	$ 3,021,696	$ 3,470,235	$ (34,880)	$ 115,260	$ 6,750,473
Equity infusion from Pinnacle West		—	150,000	—	—	—	150,000
Net Income		—	—	24,199	—	4,306	28,505
Other comprehensive income		—	—	—	820	—	820
Other		—	—	(2)	—	—	(2)
Balance, March 31, 2022	71,264,947	$ 178,162	$ 3,171,696	$ 3,494,432	$ (34,060)	$ 119,566	$ 6,929,796

	Three Months Ended March 31, 2021						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, January 1, 2021	71,264,947	$ 178,162	$ 2,871,696	$ 3,216,955	$ (40,918)	$ 119,290	$ 6,345,185
Net Income		—	—	35,287	—	4,873	40,160
Other comprehensive income		—	—	—	927	—	927
Other		—	—	2	—	1	3
Balance, March 31, 2021	71,264,947	$ 178,162	$ 2,871,696	$ 3,252,244	$ (39,991)	$ 124,164	$ 6,386,275

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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Consolidation and Nature of Operations

The unaudited condensed consolidated financial statements include the accounts of Pinnacle West and our subsidiaries: APS, 4C Acquisition, LLC ("4CA"), Bright Canyon Energy Corporation ("BCE") and El Dorado Investment Company ("El Dorado"). See Note 8 for more information on 4CA matters. Intercompany accounts and transactions between the consolidated companies have been eliminated. The unaudited condensed consolidated financial statements for APS include the accounts of APS and the Palo Verde Generating Station ("Palo Verde") sale leaseback variable interest entities ("VIEs"), see Note 6 for further discussion. 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.

Amounts reported in our interim Condensed Consolidated Statements of Income are not necessarily indicative of amounts expected for the respective annual periods, due to the effects of seasonal temperature variations on energy consumption, timing of maintenance on electric generating units ("EGU"), and other factors.

Our condensed 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. Certain information and footnote disclosures normally included in financial statements prepared in conformity with GAAP have been condensed or omitted pursuant to such regulations, although we believe that the disclosures provided are adequate to make the interim information presented not misleading. The accompanying condensed consolidated financial statements and these notes should be read in conjunction with the audited consolidated financial statements and notes included in our 2021 Form 10-K.

On June 30, 2020, the United States Federal Energy Regulatory Commission ("FERC") issued an order granting a waiver request related to the existing Allowance for Funds Used During Construction ("AFUDC") rate calculation beginning March 1, 2020, through February 28, 2021. On February 23, 2021, this waiver was extended until September 30, 2021. On September 21, 2021, it was further extended until March 31, 2022. The order provided a simplified approach that companies may elect to implement in order to minimize the significant distorted effect on the AFUDC formula resulting from increased short-term debt financing during the COVID-19 pandemic. APS adopted this simplified approach to computing the AFUDC composite rate by using a simple average of the actual historical short-term debt balances for 2019, instead of current period short-term debt balances, and left all other aspects of the AFUDC formula composite rate calculation unchanged. This change impacted the AFUDC composite rate in 2021 and for the three-month ended March 31, 2022. Furthermore, the change in the composite rate calculation did not impact our accounting treatment for these costs. The change did not have a material impact on our financial statements. See Note 1 in our 2021 Form 10-K for information on the accounting treatment for AFUDC.

Supplemental Cash Flow Information

The following table summarizes supplemental Pinnacle West cash flow information (dollars in thousands):

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
Cash paid (received) during the period for:		
Income taxes, net of refunds	$ —	$ (827)
Interest, net of amounts capitalized	55,208	53,885
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 131,778	$ 79,597
Right-of-use operating lease assets obtained in exchange for operating lease liabilities	4,889	785

The following table summarizes supplemental APS cash flow information (dollars in thousands):

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
Cash paid (received) during the period for:		
Income taxes, net of refunds	$ (25)	$ —
Interest, net of amounts capitalized	53,982	53,153
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 124,778	$ 79,597
Right-of-use operating lease assets obtained in exchange for operating lease liabilities	4,889	785

2. Revenue

Sources of Revenue

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

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
Retail Electric Service		
Residential	$ 367,346	$ 340,838
Non-Residential	359,516	314,783
Wholesale Energy Sales	28,903	17,597
Transmission Services for Others	25,492	18,993
Other Sources	2,274	4,264
Total operating revenues	$ 783,531	$ 696,475

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Retail Electric Revenue. Pinnacle West's retail electric revenue is generated by wholly owned, regulated subsidiary APS's sale of electricity to our regulated customers within the authorized service territory at tariff rates approved by the ACC and based on customer usage. Revenues related to the sale of electricity are generally recognized when service is rendered, or electricity is delivered to customers. The billing of electricity sales to individual customers is based on the reading of their meters. We obtain customers' meter data on a systematic basis throughout the month, and generally bill customers within a month from when service was provided. Customers are generally required to pay for services within 21 days of when the services are billed. See "Allowance for Doubtful Accounts" discussion below for additional details regarding payment terms.

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

In the electricity business, some contracts to purchase energy are settled by netting against other contracts to sell electricity. This is referred to as a book-out, and usually occurs in contracts that have the same terms (product type, quantities, and delivery points) and for which power does not flow. We net these book-outs, which reduces both wholesale revenues and fuel and purchased power costs.

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 three months ended March 31, 2022, and 2021 were $772 million and $682 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 three months ended March 31, 2022, and 2021, our revenues that do not qualify as revenue from contracts with customers were $12 million and $14 million, respectively. This amount includes revenues related to certain regulatory cost recovery mechanisms that are considered alternative revenue programs. We recognize revenue associated with alternative revenue programs when specific events permitting recognition are completed. Certain amounts associated with alternative revenue programs will subsequently be billed to customers; however, we do not reclassify billed amounts into revenue from contracts with customers. See Note 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 Condensed Consolidated Balance Sheets as of March 31, 2022, or December 31, 2021.

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of accounts receivable and accrued unbilled revenues that will ultimately be uncollectible due to credit loss risk. The allowance includes a write-off component that is calculated by applying an estimated write-off factor to retail electric revenues. The write-off factor used to estimate uncollectible accounts is based upon consideration of historical collections experience, the current and forecasted economic environment, changes to our collection policies, and management's best estimate of future collections success. We continue to monitor the impacts of COVID-19, our disconnection policies, payment arrangements, among other considerations impacting our estimated write-off factor and allowance for doubtful accounts.

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

	March 31, 2022	December 31, 2021
Allowance for doubtful accounts, balance at beginning of period	$ 25,354	$ 19,782
Bad debt expense	3,161	22,251
Actual write-offs	(3,849)	(16,679)
Allowance for doubtful accounts, balance at end of period	$ 24,666	$ 25,354

3. Long-Term Debt and Liquidity Matters

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.

Pinnacle West

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

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

At March 31, 2022, Pinnacle West had a $200 million revolving credit facility that matures on May 28, 2026. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on Pinnacle West's senior unsecured debt credit ratings and the agreement includes a sustainability-linked pricing metric which permits an interest rate reduction or increase by meeting or missing targets related to specific environmental and employee health and safety sustainability objectives. The facility is available to support Pinnacle West's general corporate purposes, including support for Pinnacle West's $200 million commercial paper program, for bank borrowings or for issuances of letters of credits. At March 31, 2022, Pinnacle West had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under the credit facility and $13 million outstanding commercial paper borrowings.

APS

At March 31, 2022, APS had two $500 million revolving credit facilities that total $1 billion and that mature on May 28, 2026. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings and the agreements include a sustainability-linked pricing metric which permits an interest rate reduction or increase by meeting or missing targets related to specific environmental and employee health and safety sustainability objectives. These facilities are available to support APS's general corporate purposes, including support for APS's $750 million commercial paper program, for bank borrowings or for issuances of letters of credit. At March 31, 2022, APS had no outstanding borrowings under its revolving credit facilities, no letters of credit outstanding under the credit facilities and $250 million of outstanding commercial paper borrowings.

On December 17, 2020, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved APS's short-term debt authorization equal to the sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power) and a long-term debt authorization of $7.5 billion. On April 6, 2022, APS filed an application with the ACC to increase the long-term debt limit under the terms required by APS from $7.5 billion to $8.0 billion and to continue its authorization of short-term debt granted in the 2020 financing order.

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

See "Financial Assurances" in Note 8 for a discussion of other outstanding letters of credit.

BCE

On February 11, 2022, a special purpose subsidiary of BCE entered into a credit agreement to finance capital expenditures and related costs for a 31 MW solar and battery storage project in Orange County, California that is under development by the subsidiary. The credit facilities consist of an approximately $33 million equity bridge loan facility, an approximately $42 million non-recourse construction to term loan facility, and an approximately $5 million letter of credit. In connection with the credit agreement, Pinnacle West has guaranteed the full amount of the equity bridge loan. As of March 31, 2022, $12 million has been drawn from the equity bridge loan. On April 25, 2022, BCE drew an additional $7 million from the bridge loan.

Debt Fair Value

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

	As of March 31, 2022		As of December 31, 2021	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 947,343	$ 924,200	$ 797,042	$ 792,735
APS	6,267,482	6,131,644	6,266,693	6,933,619
BCE	11,799	12,052	—	—
Total	$ 7,226,624	$ 7,067,896	$ 7,063,735	$ 7,726,354

4. Regulatory Matters

2019 Retail Rate Case

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

The principal provisions of APS’s application were:

- a test year comprised of 12 months ended June 30, 2019, adjusted as described below;
- an original cost rate base of $8.87 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

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

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

(i) a $20.8 million revenue decrease, (ii) an average annual customer bill decrease of 0.63%, (iii) a return on equity of 8.74%, (iv) a 0% return on the increment of fair value rate base, (v) the nonrecovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project pending further consideration, and (vi) the recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project.

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

The CCT plan includes the following proposed components: (i) $100 million that will be paid over 10 years to the Navajo Nation for a sustainable transition to a post-coal economy, which would be funded by customers, (ii) $1.25 million that will be paid over five years to the Navajo Nation to fund an economic development organization, which would be funds not recoverable through rates, (iii) $10 million to facilitate electrification projects within the Navajo Nation, which would be funded equally by funds not recoverable through rates and by customers, (iv) $2.5 million per year in transmission revenue sharing to be paid to the Navajo Nation beginning after the closure of the Four Corners through 2038, which would be funds not recoverable through rates, (v) $12 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, which would primarily be funded by customers, and (vi) $3.7 million that will be paid over five years to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, which would primarily be funded by customers. The commitment of funds that would not be recoverable through rates of $25 million were recognized in our December 31, 2020, financials. In 2021, APS committed an additional $900,000 to be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, and this amount was recognized in its December 31, 2021, financials.

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

On August 2, 2021, the Administrative Law Judge issued a Recommended Opinion and Order in the 2019 Rate Case (the "2019 Rate Case ROO") and issued corrections on September 10 and September 20, 2021. The 2019 Rate Case ROO recommended, among other things, (i) a $111 million decrease in annual revenue requirements, (ii) a return on equity of 9.16%, (iii) a 0.30% return on the increment of fair value rate base greater than original cost, with total fair value rate of return further adjusted to include a 0.03% reduction to return on equity resulting in an effective fair value rate of return of 4.95%, (iv) the nonrecovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project (see "Four Corners SCR Cost Recovery" below for additional information), (v) the recovery of the deferral and rate base effects of the operating costs and construction of the Ocotillo modernization project, which includes a reduction in the return on the deferral, (vi) a 15% disallowance of annual amortization of Navajo Plant regulatory asset recovery, (vii) the denial of the request to defer, until APS's next general rate case, the increase or decrease in its Arizona property taxes attributable to tax rate changes, and (viii) a collaborative process to review and recommend revisions to APS's adjustment mechanisms within 12 months after the date of the decision. The 2019 Rate Case ROO also recommended that the CCT plan include the following components: (i) $50 million that will be paid over 10 years to the Navajo Nation, (ii) $5 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, and (iii) $1.675 million that will be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant. These amounts would be recoverable from APS's customers through the Arizona Renewable Energy Standard and Tariff ("RES") adjustment mechanism. APS filed exceptions on September 13, 2021, regarding the disallowance of the SCR cost deferrals and plant investments that was recommended in the 2019 Rate Case ROO, among other issues.

On October 6, 2021 and October 27, 2021, the ACC voted on various amendments to the 2019 Rate Case ROO that would result in, among other things, (i) a return on equity of 8.70%, (ii) the recovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project, with the exception of $215.5 million (see "Four Corners SCR Cost Recovery" below), (iii) that the CCT plan include the following components: (a) a payment of $1 million to the Hopi Tribe within 60 days of the 2019 Rate Case decision, (b) a payment of $10 million over three years to the Navajo Nation, (c) a payment of $0.5 million to the Navajo County communities within 60 days of the 2019 Rate Case decision, (d) up to $1.25 million for electrification of homes and businesses on the Hopi reservation and (e) up to $1.25 million for the electrification of homes and businesses on the Navajo Nation reservation. These payments and expenditures are attributable to the future closures of Four Corners and Cholla, along with the prior closure of the Navajo Plant and all ordered payments and expenditures would be recoverable through rates, and (iv) a change in the residential on-peak time-of-use period from 3 p.m. to 8 p.m. to 4 p.m. to 7 p.m. Monday through Friday, excluding holidays. The 2019 Rate Case ROO, as amended, results in a total annual revenue decrease for APS of $4.8 million, excluding temporary CCT payments and expenditures. On November 2, 2021, the ACC approved the 2019 Rate Case ROO, as amended. On November 24, 2021, APS filed an application for rehearing of the 2019 Rate Case with the ACC and the application was deemed denied on December 15, 2021, as the ACC did not act upon it. On December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals and a Petition for Special Action with the Arizona Supreme Court, requesting review of the disallowance of $215 million of Four Corners SCR plant investments and deferrals (see "Four Corners SCR Cost Recovery" below for additional information) and the 20 basis point penalty reduction to the return on equity. On February 8, 2022, the Arizona Supreme Court declined to accept jurisdiction on APS's Petition for Special Action. The appeal at the Arizona Court of Appeals is proceeding in the normal course. APS cannot predict the outcome of this proceeding.

Consistent with the 2019 Rate Case decision, APS implemented the new rates effective as of December 1, 2021. On December 3, 2021, ACC Staff notified the ACC of a discrepancy between the written decision, which approved the change in time-of-use on-peak hours to 4 p.m. to 7 p.m. but did not explicitly approve the 10 months contemplated in APS's verbal testimony to implement the new time-of-use hours. On December 16, 2021, the ACC ordered APS to complete the implementation of the time-of-use peak period by April 1, 2022. On January 12, 2022, the ACC voted to extend the deadline until September 1, 2022, to complete the implementation of the new on-peak hours for residential customers. In addition, the ACC ordered extensive compliance and reporting obligations and will be continuing to explore whether penalties or rebates would be owed to certain customers. APS cannot predict the outcome of this matter.

Additionally, consistent with the 2019 Rate Case decision, as of April 2022, APS has completed the following payments that will be recoverable through rates related to the CCT: (i) $3.33 million to the Navajo Nation; (ii) $500,000 to the Navajo County communities; and (iii) $1 million to the Hopi Tribe. Consistent with APS's commitment to the impacted communities, APS has also completed the following payments: (i)$500,000 to the Navajo Nation for electrification; (ii) $1.1 million to the Navajo County Communities for

CCT and economic development; and (iii) $1.25 million to the Hopi Tribe for CCT and economic development. The ACC has also authorized $1.25 million to be recovered through rates for electrification of homes and businesses on both the Navajo Nation and Hopi reservation. Expenditure of these funds is contingent upon completion of a census of the unelectrified homes and businesses within APS service territory on both the Navajo Nation and Hopi reservation.

APS expects to file an application with the ACC for its next general retail rate case by mid-year 2022 but is continuing to evaluate the timing of such filing.

Information Technology ACC Investigation

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

2016 Retail Rate Case Filing

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates. On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, RUCO, limited income advocates and private rooftop solar organizations signed a settlement agreement (the "2017 Settlement Agreement") and filed it with the ACC. The 2017 Settlement Agreement provides for 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.

Other key provisions of the 2017 Settlement Agreement include the following:

- 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 the 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 Power Supply Adjustor ("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 to 7 p.m. to 3 p.m. to 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.

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

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

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs outside of a general retail rate case through the following recovery mechanisms.

Renewable Energy Standard. In 2006, the ACC approved the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to recover the approved amounts for use on renewable energy projects. Each year, APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year’s RES budget. In 2015, the ACC revised the RES rules to allow the ACC to consider all available information, including the number of rooftop solar arrays in a utility’s service territory, to determine compliance with the RES.

On November 20, 2017, APS filed an updated 2018 RES budget to include budget adjustments for APS Solar Communities (formerly known as AZ Sun II), which was approved as part of the 2017 Rate Case Decision. APS Solar Communities is a 3-year program authorizing APS to spend $10 million to $15 million in capital costs each year to install utility-owned DG systems for low to moderate income residential homes, non-profit entities, Title I schools and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES.

On July 1, 2019, APS filed its 2020 RES Implementation Plan and proposed a budget of approximately $86.3 million. APS’s budget request supports existing approved projects and commitments and requests a permanent waiver of the RES residential distributed energy requirement for 2020. On September 23, 2020, the ACC approved the 2020 RES Implementation Plan, including APS's requested waiver of the residential distributed energy requirements for 2020. In addition, the ACC approved the implementation of a new pilot program that incentivizes Arizona households to install at-home battery systems. Recovery of the costs associated with the pilot will be addressed in the 2021 Demand Side Management Implementation Plan (“DSM Plan”).

On July 1, 2020, APS filed its 2021 RES Implementation Plan and proposed a budget of approximately $84.7 million. APS’s budget request supports existing approved projects and commitments and requests a permanent waiver of the RES residential distributed energy requirement for 2021. In the 2021 RES

Implementation Plan, APS requested $4.5 million to meet revenue requirements associated with the APS Solar Communities program to complete installations delayed as a result of the COVID-19 pandemic in 2020. On June 7, 2021, the ACC approved the 2021 RES Implementation Plan, including APS's requested waiver of the residential distributed energy requirements for 2021. As part of the approval, the ACC approved the requested budget and authorized APS to collect $68.3 million through the Renewable Energy Adjustment Charge to support APS’s RES programs.

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

On July 1, 2021, APS filed its 2022 RES Implementation Plan and proposed a budget of approximately $93.1 million. APS filed an amended 2022 RES Implementation Plan on December 9, 2021, with a proposed budget of $100.5 million. This budget includes funding for programs to comply with the decision in the 2019 Rate Case, including the ACC authorizing spending $20 million to $30 million in capital costs for the APS Solar Communities program each year for a period of three years from the effective date of the 2019 Rate Case decision. APS’s budget proposal supports existing approved projects and commitments and requests a permanent waiver of the RES residential and non-residential distributed energy requirements for 2022. The ACC has not yet ruled on the 2022 RES Implementation Plan.

In response to an ACC inquiry, the ACC Staff filed a report providing the history of APS’s long-term purchased power contract of the 280 MW Concentrating Solar Power Plant. This report outlines alternative options that the ACC could pursue to address the costs of this contract, which was executed in February 2008. APS cannot predict the outcome of this matter.

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

On September 1, 2017, APS filed its 2018 DSM Plan, which proposed modifications to the DSM 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 sought a requested budget of $52.6 million and requested 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.

On December 31, 2018, APS filed its 2019 DSM Plan, which requested a budget of $34.1 million and focused on DSM strategies to better meet system and customer needs, such as peak demand reduction, load shifting, storage and electrification strategies.

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

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

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

On April 20, 2021, APS filed a request to extend the June 1, 2021, deadline to file its 2022 DSM Plan until 120 days after the ACC has taken action on APS's amended 2021 DSM Plan. The ACC approved the request, granting an extension until 120 days after the ACC action on the 2021 DSM Plan, or December 31, 2021, whichever is later. On December 17, 2021, APS filed its 2022 DSM Plan which requested a budget of $78.4 million and represents an increase of approximately $14 million in DSM spending above 2021. The ACC has not yet ruled on the 2022 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 following table shows the changes in the deferred fuel and purchased power regulatory asset for 2022 and 2021 (dollars in thousands):

	Three Months Ended March 31,	
	2022	**2021**
Beginning balance	$ 388,148	$ 175,835
Deferred fuel and purchased power costs — current period	6,110	52,210
Amounts (charged) refunded to customers	(39,442)	564
Ending balance	$ 354,816	$ 228,609

The PSA rate for the PSA year beginning February 1, 2019, was $0.001658 per kWh, as compared to the $0.004555 per kWh for the prior year. This rate was comprised 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. These rates went into effect as filed on February 1, 2019.

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

On November 30, 2020, APS filed its PSA rate for the PSA year beginning February 1, 2021. That rate was $0.003544 per kWh, which consisted of a forward component of $0.003434 per kWh and a historical component of $0.000110 per kWh. The 2021 PSA rate is a $0.004 per kWh increase compared to the 2020 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. This left $215.9 million of fuel and purchased power costs above this annual cap which will be reflected in future year resets of the PSA. These rates were to be effective on February 1, 2021, but APS delayed the effectiveness of these rates until the first billing cycle of April 2021 due to concerns of the impact on customers during COVID-19. In March 2021, the ACC voted to implement the 2021 PSA rate on a staggered basis, with 50% of the rate increase taking effect in April 2021, and the remaining 50% taking effect in November 2021. The PSA rate implemented on April 1, 2021 was $0.001544 per kWh, which consisted of a forward component of $(0.004444) per kWh and a historical component of $0.005988 per kWh. On November 1, 2021, the remaining increase was implemented to a rate of $0.003544 per kWh and consisted of a forward component of $(0.004444) per kWh and a historical component of $0.007988 per kWh. As part of this approval, the ACC ordered ACC Staff to conduct a fuel and purchased power procurement audit to better understand the factors that contributed to the increase in fuel costs.

On April 1, 2022, the ACC filed a final report of its audit of APS's fuel and purchased power costs for the period January 2019 through January 2021. The report contains an in-depth review of APS's fuel and purchased power contracts, its monthly fuel accounting activities, its forecasting and dispatching procedures, and its monthly PSA filings, among other fuel-related activities. The report finds that the APS's fuel processing accounting practices, dispatching procedures, and procedures for hedging activity are reasonable and appropriate. The report includes several recommendations for the ACC's consideration, including review of current contracts, maintenance schedules, and certain changes and improvements to the schedules in APS's monthly PSA filings. APS continues to review the report and its recommendations. APS cannot predict the final outcome of this audit.

On November 30, 2021, APS filed its PSA rate for the PSA year beginning February 1, 2022. That rate was $0.007544 per kWh, which consisted of a forward component of $(0.004842) per kWh and a historical component of $0.012386 per kWh. The 2022 PSA rate is a $0.004 per kWh increase compared to the 2021 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. These rates went into effect as filed on February 1, 2022. At the time of the compliance filing, the amount remaining over the annual cap was approximately $365 million of fuel and purchased power costs which will be reflected in future year resets of the PSA.

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

Environmental Improvement Surcharge. The EIS permits APS to recover the capital carrying costs (rate of return, depreciation and taxes) plus incremental operations and maintenance expenses associated with

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environmental improvements made outside of a test year to comply with environmental standards set by federal, state, tribal, or local laws and regulations. A filing is made on or before February 1 each year for qualified environmental improvements since the prior rate case test year, and the new charge becomes effective April 1 unless suspended by the ACC. There is an overall cap of $0.0005 per kWh (approximately $13 million to $14 million per year). APS's February 1, 2022, application requested an increase in the charge to $11.4 million, or $1.1 million over the prior-period charge, and it became effective with the first billing cycle in April 2022.

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

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

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

Effective June 1, 2019, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $25.8 million for the 12-month period beginning June 1, 2019, in accordance with the FERC-approved formula. Of this amount, wholesale customer rates increased by $21.1 million and retail customer rates would have increased by approximately $4.7 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved TCA balancing account, the retail revenue requirement increased by a total of $4.9 million, resulting in a decrease to residential rates and an increase to commercial rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2019.

Effective June 1, 2020, APS's annual wholesale transmission revenue requirement for all users of its transmission system decreased by approximately $6.1 million for the 12-month period beginning June 1, 2020, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by $4.8 million and retail customer rates would have decreased by approximately $10.9 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by a total of $7.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2020.

Effective June 1, 2021, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $4 million for the 12-month period beginning June 1, 2021, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates decreased by approximately $3.2 million and retail customer rates would have increased by approximately $7.2 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC approved balancing account, the retail revenue requirement decreased by $28.4 million, resulting in reductions to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2021.

Lost Fixed Cost Recovery Mechanism. The LFCR mechanism permits APS to recover on an after-the-fact basis a portion of its fixed costs that would otherwise have been collected by APS in the kWh sales lost due to APS energy efficiency programs and to DG such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism were 2.5 cents for both lost residential and non-residential kWh as set forth in the 2017 Settlement Agreement. The fixed costs recoverable by the LFCR mechanism are currently 2.56 cents for lost residential and 2.68 cents non-residential kWh as set forth in the 2019 Rate Case decision. The LFCR adjustment has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWhs lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. DG sales losses are determined from the metered output from the DG units.

On February 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). On April 14, 2020, the ACC approved the 2020 LFCR adjustment as filed, effective with the first billing cycle in May 2020. On February 15, 2021, APS filed its 2021 annual LFCR adjustment, requesting that effective May 1, 2021, the annual LFCR recovery amount be increased to $38.5 million (an $11.8 million increase from previous levels). On April 13, 2021, the ACC voted not to approve the requested $11.8 million increase to the annual LFCR adjustment, thus the previously approved rates continue to remain intact. The $11.8 million will continue to be maintained in the LFCR regulatory asset balancing account and will be included in APS's next LFCR application filing in accordance with the compliance requirements.

As a result of the 2019 Rate Case decision, APS's annual LFCR adjustor rate will be dependent on an annual earnings test filing, which will compare APS's previous year's rate of return with the related authorized rate of return. If the actual rate of return is higher than the authorized rate of return, the LFCR rate for the subsequent year is set at zero. APS determined that the changes to the LFCR mechanism as a result of the 2019 Rate Case decision did not materially impact its results of operations and financial statements for the year ended December 31, 2021.

On February 15, 2022, APS filed its 2022 annual LFCR adjustment, requesting that effective May 1, 2022, the annual LFCR recovery amount be increased to $59.1 million (a $32.5 million increase from previous levels). As a result of certain changes made to the LFCR mechanism in the 2019 Rate Case decision, APS has stopped alternative revenue program accounting treatment for the LFCR mechanism, which impacts the timing of revenue recognition. The ACC’s final determination of APS’s 2022 annual LFCR adjustment filing may materially impact our financial statement results.

On March 29, 2022, the ACC Staff filed its report and proposed order regarding APS’s 2022 LFCR adjustment concluding that APS calculated the adjustment in accordance with its Plan of Administration. The ACC Staff recommends approval of the LFCR adjustment, subject to its final review of the earnings test. The ACC has not yet ruled on the 2022 annual LFCR adjustment. APS cannot predict the outcome or timing of the ACC’s consideration and final determination of its 2022 annual LFCR adjustment filing.

Tax Expense Adjustor Mechanism. As part of the 2017 Settlement Agreement, the parties agreed to a rate adjustment mechanism to address potential federal income tax reform and enable the pass-through of certain income tax effects to customers. The TEAM expressly applies to APS’s retail rates with the exception of a small subset of customers taking service under specially-approved tariffs. On December 22, 2017, the Tax Act was enacted. This legislation made significant changes to the federal income tax laws including a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018.

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

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

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

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

Net Metering

APS's 2017 Rate Case Decision provides that payments by utilities for energy exported to the grid from residential DG solar facilities will be determined using a RCP methodology as determined in the ACC's generic Value and Cost of Distributed Generation docket. RCP is a method that is based on the most recent five-year rolling average price that APS incurs for utility-scale solar projects. The price established by this RCP method will be updated annually (between general retail rate cases) but will not be decreased by more than 10% per year. The ACC is no longer pursuing development of a forecasted avoided cost methodology as an option for utilities in place of the RCP. Commercial customers, grandfathered residential solar customers, and residential customers with DG systems other than solar facilities continue to qualify for net metering.

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

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

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

In accordance with the 2017 Rate Case Decision, APS filed its request for a RCP export energy price of 10.5 cents per kWh on May 1, 2019. This price also reflects the 10% annual reduction discussed above. The new rate rider became effective on October 1, 2019. APS filed its request for a fourth-year export energy price of 9.4 cents per kWh on May 1, 2020, with a requested effective date of September 1, 2020. This price reflects the 10% annual reduction discussed above. On September 23, 2020, the ACC approved the annual reduction of the export energy price but voted to delay the effectiveness of the reduction in export prices until October 1, 2021. In accordance with this decision, the RCP export energy price of 9.4 cents per kWh became effective on October 1, 2021. On April 29, 2022, APS filed an application to decrease the RCP price to 8.46 cents per kWh, reflecting a 10% annual reduction, to become effective September 1, 2022, upon ACC approval.

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

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Subpoena from Former Arizona Corporation Commissioner Robert Burns

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

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

In its March 4, 2021, opinion, the Court of Appeals affirmed the trial court's dismissal of Burns' complaint, concluding that Burns could not overturn the ACC's 4-1 vote refusing to enforce his subpoenas. On May 15, 2021, Burns filed a petition for review with the Arizona Supreme Court asking for reversal of the Court of Appeals opinion and the trial court's judgment. APS and the ACC filed responses to Burns' petition on July 14, 2021, requesting that the petition be denied. The Arizona Supreme Court granted Burns' petition and heard oral argument on March 8, 2022. Pinnacle West and APS cannot predict the outcome of this matter.

Energy Modernization Plan

On January 30, 2018, the initial Energy Modernization Plan was proposed, which consisted of a series of energy policies tied to clean energy sources such as energy storage, biomass, energy efficiency, electric vehicles, and expanded energy planning through the integrated resource plan ("IRP") process. On April 25, 2019, the ACC Staff issued an initial set of draft energy rules and subsequent drafts were filed by ACC Staff in July 2019, February 2020, and July 2020. On July 30, 2020, the ACC Staff issued final draft energy rules which proposed 100% of retail kWh sales from clean energy resources by the end of 2050. Nuclear power was defined as a clean energy resource. The proposed rules also required 50% of retail energy served be renewable by the end of 2035. A new EES was not included in the proposed rules. These rules would have required utilities to file a Clean Energy Implementation Plan and Energy Efficiency Report as part of their IRP every three years beginning in 2023. In addition, these rules would have changed the IRP planning horizon from 15 years to 10 years.

The ACC discussed the final draft energy rules at several different meetings in 2020 and 2021. On November 13, 2020, the ACC approved a final draft energy rules package. On April 19, 2021, the Administrative Law Judge issued a Recommended Order and Opinion on the final energy rules. In June 2021, the ACC adopted clean energy rules based on a series of ACC amendments. The adopted rules included a final standard of 100% clean energy by 2070 and the following interim standards for carbon reduction from baseline carbon emissions level: 50% reduction by December 31, 2032; 65% reduction by December 31, 2040; 80% reduction by December 31, 2050, and 95% reduction by December 31, 2060. Since the adopted clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider all-source RFP requirements and the IRP process. During March 2022, the ACC reviewed several proposed amendments for a proposed all-source RFP and IRP rulemaking package but delayed a vote on the amendments to a future date. APS cannot predict the outcome of this matter.

Integrated Resource Planning

ACC rules require utilities to develop 15-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. Based on an ACC decision, APS was originally required to file its next IRP by April 1, 2020. On February 20, 2020, the ACC extended the deadline for all utilities to file their IRPs from April 1, 2020, to June 26, 2020. On June 26, 2020, APS filed its final IRP. On July 15, 2020, the ACC extended the schedule for final ACC review of utility IRPs to February 2021. In February 2022, the ACC acknowledged APS's IRP. The ACC also approved certain amendments to the IRP process, including, setting an EES of 1.3% of retail sales annually (averaged over a three-year period) and a demand-side resource capacity of 35% of 2020 peak demand by 2030 and authorizing future rate base treatment of qualifying demand-side resources as proposed in future rate cases. See "Energy Modernization Plan" above for information regarding proposed changes to the IRP filings.

Public Utility Regulatory Policies Act

Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), qualifying facilities are provided the right to sell energy and/or capacity to utilities and are granted relief from certain regulatory burdens. On December 17, 2019, the ACC mandated a minimum contract length of 18 years for qualifying facilities over 100 kW in Arizona and established that the rate paid to qualifying facilities must be based on the long-term avoided cost. "Avoided cost" is generally defined as the price at which the utility could purchase or produce the same amount of power from sources other than the qualifying facility on a long-term basis. During calendar year 2020, APS entered into two 18-year PPAs with qualified facilities, each for 80 MW solar facilities. In March 2021, the ACC approved these agreements.

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

Residential Electric Utility Customer Service Disconnections

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

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

APS suspended the disconnection of customers for nonpayment from June 1, 2021, through October 15, 2021 and customers with past due balances of $75 or greater as of that date were automatically placed on six-month payment arrangements. APS voluntarily began waiving late payment fees of its customers on March 13, 2020. APS is continuing to waive late payment fees for residential customers. However, starting May 1, 2022, commercial and industrial customers will start to incur late payment fees. APS has experienced and is continuing to experience an increase in bad debt expense associated with the Summer Disconnection Moratorium and the related write-offs of customer delinquent accounts.

Retail Electric Competition Rules

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC's retail electric competition rules. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACC's retail electric competition rules. During a July 15, 2020, ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. The ACC continues to discuss matters related to retail electric competition, including the potential for additional buy-through programs or other pilot programs. In April 2022, the Arizona Legislature passed a bill that would nullify a 20-year-old electric deregulation law that has been in place since 1998. The bill was signed by the Arizona Governor and will take effect 90 days after the adjournment of the legislative session. APS cannot predict what impact this change, if any, will have on APS.

On August 4, 2021, Green Mountain Energy filed an application seeking a certificate of convenience and necessity to allow it to provide competitive electric generation service in Arizona. Green Mountain Energy has requested that the ACC grant it the ability to provide competitive service in APS's and Tucson Electric Power Company's certificated service territories and proposes to deliver a 100% renewable energy product to residential and general service customers in those service territories. APS opposes Green Mountain Energy's application and intends to intervene to contest it. On November 3, 2021, the ACC submitted questions to the Arizona Attorney General requesting legal opinions related to a number of issues surrounding retail electric competition and the ACC's ability to issue competitive certificates convenience and necessity. On November 26, 2021, the Administrative Law Judge issued a procedural order indicating it would not be appropriate to set a schedule until the Attorney General has provided his insights on the applicable law.

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

Rate Plan Comparison Tool and Investigation

On November 14, 2019, APS learned that its rate plan comparison tool was not functioning as intended due to an integration error between the tool and APS's meter data management system. APS immediately removed the tool from its website and notified the ACC. The purpose of the tool was to provide customers with a rate plan recommendation based upon historical usage data. Upon investigation, APS determined that the error may have affected rate plan recommendations to customers between February 4, 2019, and November 14, 2019. By the middle of May 2020, APS provided refunds to approximately 13,000 potentially impacted customers equal to the difference between what they paid for electricity and the amount they would have paid had they selected their most economical rate, as applicable, and a $25 payment for any inconvenience that the customer may have experienced. The refunds and payment for inconvenience being provided did not have a material impact on APS's financial statements. In February 2020, APS launched a new online rate comparison tool. The ACC hired an outside consultant to evaluate the extent of the error and the overall effectiveness of the tool. On August 20, 2020, ACC Staff filed the outside consultant's report on APS's rate comparison tool. The report concluded APS's new rate comparison tool is working as intended. The report also identified a small population of additional customers that may have been affected by the error and APS has provided refunds and the $25 inconvenience payment to approximately 3,800 additional customers. These additional refunds and payment for inconvenience did not have a material impact on APS's financial statements. On September 28, 2020, the ACC discussed this report but did not take any action. APS cannot predict whether additional inquiries or actions may be taken by the ACC.

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

Four Corners SCR Cost Recovery

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

On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance and the appeal is proceeding in the normal course. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of March 31, 2022. If the

2019 Rate Case decision to disallow $215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately $154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See above for further discussion on the 2019 Rate Case decision.

Cholla

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

Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS has been recovering a return on and of the net book value of the unit in base rates. Pursuant to the 2017 Settlement Agreement described above, APS will be allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs, $40.6 million as of March 31, 2022, in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. In accordance with the 2019 Rate Case decision, the regulatory asset is being amortized through 2033.

Navajo Plant

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

APS has been recovering a return on and of the net book value of its interest in the Navajo plant in base rates over its previously estimated life through 2026. Pursuant to the 2019 Rate Case decision described above, APS will be allowed continued recovery of the book value of its remaining investment in the Navajo plant, $59.8 million as of March 31, 2022, in addition to a return on the net book value, with the exception of 15% of the annual amortization expense in rates. In addition, APS will be allowed recovery of other costs related to retirement and closure, including the Navajo coal reclamation regulatory asset, $16.1 million as of March 31, 2022. The disallowed recovery of 15% of the annual amortization does not have a material impact on APS financial statements.

Regulatory Assets and Liabilities

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

		March 31, 2022		December 31, 2021	
	Amortization Through	Current	Non-Current	Current	Non-Current
Pension	(a)	$ —	$ 506,280	$ —	$ 509,751
Deferred fuel and purchased power (b) (c)	2023	354,816	—	388,148	—
Income taxes — allowance for funds used during construction ("AFUDC") equity	2052	7,625	165,071	7,625	164,768
Ocotillo deferral (e)	2031	9,507	135,766	9,507	138,143
Retired power plant costs	2033	15,455	94,902	15,160	99,681
SCR deferral (e)(f)	2031	8,147	95,588	8,147	97,624
Lost fixed cost recovery (b)	2023	57,808	—	63,889	—
Deferred property taxes	2027	8,569	38,915	8,569	41,057
Deferred compensation	2036	—	35,355	—	33,997
Income taxes — investment tax credit basis adjustment	2056	826	23,899	1,129	23,639
Four Corners cost deferral	2024	8,077	13,979	8,077	15,998
Palo Verde VIEs (Note 6)	2046	—	21,053	—	21,094
Coal reclamation	2026	2,978	13,118	2,978	13,862
Loss on reacquired debt	2038	1,648	8,976	1,648	9,372
Active Union Medical Trust	(g)	—	10,453	—	1,175
TCA balancing account (b)	2023	8,205	2,038	170	3,663
Mead-Phoenix transmission line contributions in aid of construction ("CIAC")	2050	332	8,965	332	9,048
Tax expense adjustor mechanism (b)	2031	656	5,681	656	5,845
Tax expense of Medicare subsidy	2024	1,235	2,406	1,235	2,469
Other	Various	376	1,801	1,254	1,801
Total regulatory assets (d)		$ 486,260	$ 1,184,246	$ 518,524	$ 1,192,987

(a) This asset represents the future recovery of pension benefit obligations and expense through retail rates. If these costs are disallowed by the ACC, this regulatory asset would be charged to OCI and result in lower future revenues. As a result of the 2019 Rate Case decision, the amount authorized for inclusion in rate base was determined using an averaging methodology, which resulted in a reduced return in retail rates. See Note 5 for further discussion.
(b) See "Cost Recovery Mechanisms" discussion above.
(c) Subject to a carrying charge.
(d) There are no regulatory assets for which the ACC has allowed recovery of costs, but not allowed a return by exclusion from rate base. FERC rates are set using a formula rate as described in "Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters."
(e) Balance includes amounts for future regulatory consideration and amortization period determination.
(f) See "Four Corners SCR Cost Recovery" discussion above.
(g) Collected in retail rates.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	Amortization Through	March 31, 2022 Current	March 31, 2022 Non-Current	December 31, 2021 Current	December 31, 2021 Non-Current
Excess deferred income taxes — ACC - Tax Act (a)	2046	$ 40,903	$ 969,459	$ 40,903	$ 971,545
Excess deferred income taxes — FERC - Tax Act (a)	2058	7,239	221,508	7,239	221,877
Asset retirement obligations	2057	—	537,720	—	614,683
Other postretirement benefits	(d)	37,789	324,697	37,789	337,027
Deferred fuel and purchased power — mark-to-market (Note 7)	2024	214,571	91,521	60,693	46,908
Removal costs	(c)	69,054	48,302	69,476	50,104
Income taxes — change in rates	2051	2,876	64,655	2,876	64,802
Four Corners coal reclamation	2038	2,316	51,629	2,316	53,076
Income taxes — deferred investment tax credit	2056	2,264	47,253	2,264	47,337
Spent nuclear fuel	2027	6,631	37,136	6,701	38,581
Renewable energy standard (b)	2023	30,729	452	38,453	187
FERC transmission true up (b)	2024	27,595	375	21,379	12,924
Property tax deferral (e)	2024	4,671	14,353	4,671	15,521
Sundance maintenance	2031	—	14,571	—	13,797
Demand side management (b)	2023	1,111	9,216	—	5,417
Tax expense adjustor mechanism (b) (e)	N/A	—	4,835	—	4,835
Other	Various	1,029	990	1,511	592
Total regulatory liabilities		$ 448,778	$ 2,438,672	$ 296,271	$ 2,499,213

(a) For purposes of presentation on the Statement of Cash Flows, amortization of the regulatory liabilities for excess deferred income taxes are reflected as “Deferred income taxes” under Cash Flows From Operating Activities.
(b) See “Cost Recovery Mechanisms” discussion above.
(c) In accordance with regulatory accounting guidance, APS accrues removal costs for its regulated assets, even if there is no legal obligation for removal.
(d) See Note 5.
(e) Balance includes amounts for future regulatory consideration and amortization period determination.

5. Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan, a non-qualified supplemental excess benefit retirement plan, and other postretirement benefit plans for the employees of Pinnacle West and our subsidiaries. The other postretirement benefit plans include a group life and medical plan and a post-65 retiree health reimbursement arrangement (“HRA”). 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	Pension Benefits		Other Benefits	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2022	2021	2022	2021
Service cost — benefits earned during the period	$ 14,331	$ 15,679	$ 4,218	$ 4,557
Non-service costs (credits):				
Interest cost on benefit obligation	27,023	24,669	4,463	4,162
Expected return on plan assets	(46,394)	(50,608)	(11,510)	(10,361)
Amortization of:				
Prior service credit	—	—	(9,447)	(9,427)
Net actuarial loss (gain)	4,768	3,985	(2,982)	(2,405)
Net periodic benefit	$ (272)	$ (6,275)	$ (15,258)	$ (13,474)
Portion of benefit charged to expense	$ (3,290)	$ (8,011)	$ (10,895)	$ (9,528)

Contributions

We have not made any voluntary contributions to our pension plan year-to-date in 2022. The minimum required contributions for the pension plan are zero and we do not expect to make any contributions in 2022, 2023 or 2024. With regard to contributions to our other postretirement benefit plan, we have not made a contribution year-to-date in 2022 and do not expect to make any contributions in 2022, 2023 or 2024.

6. Palo Verde Sale Leaseback Variable Interest Entities

In 1986, APS entered into agreements with three separate VIE lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. APS will retain the assets through 2033 under all three lease agreements. APS will be required to make payments relating to the three leases in total of approximately $21 million annually for the period 2022 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 for the three months ended March 31, 2022, of $4 million and for the three months ended March 31, 2021 of $5 million. 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 Condensed Consolidated Balance Sheets at March 31, 2022, and December 31, 2021, include the following amounts relating to the VIEs (dollars in thousands):

	March 31, 2022	December 31, 2021
Palo Verde sale leaseback property, plant and equipment, net of accumulated depreciation	$ 93,199	$ 94,166
Equity — Noncontrolling interests	119,566	115,260

Assets of the VIEs are restricted and may only be used for payment to the noncontrolling interest holders. These assets are reported on our condensed consolidated financial statements.

APS is exposed to losses relating to these VIEs upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the Nuclear Regulatory Commission ("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 $315 million beginning in 2022, and up to $501 million over the lease terms.

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

7. Derivative Accounting

Derivative financial instruments are used to manage exposure to commodity price and transportation costs of electricity, natural gas, emissions allowances, and interest rates. Risks associated with market volatility are managed by utilizing various physical and financial derivative instruments, including futures, forwards, options and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and natural gas. Derivative instruments that meet certain hedge accounting criteria may be designated as cash flow hedges and are used to limit our exposure to cash flow variability on forecasted transactions. The changes in market value of such instruments have a high correlation to price changes in the hedged transactions. Derivative instruments are also entered into for economic hedging purposes. While economic hedges may mitigate exposure to fluctuations in commodity prices, these instruments have not been designated as accounting hedges. Contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow are netted, which reduces both revenues and fuel and purchased power costs in our Condensed Consolidated Statements of Income, but does not impact our financial condition, net income or cash flows.

Our derivative instruments, excluding those qualifying for a scope exception, are recorded on the balance sheets as an asset or liability and are measured at fair value. See Note 11 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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.

The following table shows the outstanding gross notional volume of derivatives, which represent both purchases and sales (does not reflect net position):

		Quantity	
Commodity	**Unit of Measure**	**March 31, 2022**	**December 31, 2021**
Power	GWh	1,171	—
Gas	Billion cubic feet	161	155

Gains and Losses from Derivative Instruments

For the three months ended March 31, 2022 and 2021, APS had no derivative instruments in designated accounting hedging relationships.

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments (dollars in thousands):

		Three Months Ended March 31,	
Commodity Contracts	**Financial Statement Location**	**2022**	**2021**
Net Gain Recognized in Income	Fuel and purchased power (a)	$ 223,742	$ 26,859

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

Derivative Instruments in the Condensed 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 Condensed Consolidated Balance Sheets. Transactions that do not allow for offsetting of positive and negative positions are reported gross on the Condensed 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. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, trade receivables and trade payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting tables presented below.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

As of March 31, 2022: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheets
Current assets	$ 214,723	$ (8,671)	$ 206,052	$ 50	$ 206,102
Investments and other assets	91,521	—	91,521	—	91,521
Total assets	306,244	(8,671)	297,573	50	297,623
Current liabilities	(152)	71	(81)	(1,625)	(1,706)
Deferred credits and other	—	—	—	—	—
Total liabilities	(152)	71	(81)	(1,625)	(1,706)
Total	$ 306,092	$ (8,600)	$ 297,492	$ (1,575)	$ 295,917

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) Includes cash collateral received from a counterparty of $8,600 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 $1,625 and cash margin provided to counterparties of $50.

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

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting.
(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $1,635 and cash margin provided to counterparties of $50.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 March 31, 2022, we have two counterparties for which our exposure represents approximately 27% of Pinnacle West's $298 million of risk management assets. This exposure relates to master agreements with counterparties, and both are rated as investment grade. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of our trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies 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).

As of March 31, 2022, we have no material derivative instruments in a net liability position with credit-risk-related contingent features, and no material cash collateral posted or required to be posted in the event of a credit-risk-related triggering event.

We have energy-related non-derivative instrument contracts with investment grade credit-related contingent features, which could require us to post additional collateral of approximately $77 million if our debt credit ratings were to fall below investment grade.

8. 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 United States Department of Energy ("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, 2022.

APS has submitted seven claims pursuant to the terms of the August 18, 2014 settlement agreement, for seven separate time periods during July 1, 2011 through June 30, 2020. The DOE has approved and paid $111.8 million for these claims (APS's share is $32.5 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 November 1, 2021, APS filed its eighth claim pursuant to the terms of the August 18, 2014 settlement agreement in the amount of $12.2 million (APS's share is $3.6 million). On March 22, 2022, the DOE approved a payment of $12.1 million (APS's share is $3.5 million) and on April 19, 2022, APS received this payment.

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 $13.5 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 $13.1 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 $22.3 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 $62.8 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.

Contractual Obligations

As of March 31, 2022, our fuel and purchased power and purchase obligation commitments have increased from the information provided in our 2021 Form 10-K. The increase is primarily due to new purchased power and energy storage commitments of approximately $1.2 billion. The majority of the changes relate to 2024 and thereafter. This amount includes approximately $500 million of commitments relating to a new purchased power lease contract that is included in our non-commenced lease discussion below.

At March 31, 2022, we have various lease arrangements that have been executed but have not yet commenced. These arrangements primarily relate to energy storage assets, with expected lease commencement dates ranging from June 2022 through June 2024, with terms expiring through May 2044. We expect the total fixed consideration paid for these arrangements, which includes both lease and nonlease payments, will approximate $1.8 billion over the term of the arrangements. For additional information regarding our lease commitments see our 2021 Form 10-K.

Other than the items described above, there have been no material changes, as of March 31, 2022, outside the normal course of business in contractual obligations from the information provided in our 2021 Form 10-K. See Note 3 for discussion regarding changes in our short-term and long-term debt obligations.

Superfund and Other Related Matters

The Comprehensive Environmental Response Compensation and Liability Act ("Superfund" or "CERCLA") establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who released, generated, transported to or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible (each a "PRP"). PRPs may be strictly, jointly, and severally liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 ("OU3") in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study ("RI/FS"). 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 later in 2022. APS's estimated costs related to this investigation and study are approximately $3 million. APS anticipates 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

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investigation into groundwater contamination in this area, on January 25, 2015, the Arizona Department of Environmental Quality ("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.

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

Arizona Attorney General Matter

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

Four Corners SCR Cost Recovery

As part of APS's 2019 Rate Case, APS included recovery of the deferral and rate base effects of the Four Corners SCR project. On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance and the appeal is proceeding in the normal course. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of March 31, 2022. If the 2019 Rate Case decision to disallow $215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately $154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See Note 4 for additional information regarding the Four Corners SCR cost recovery.

Environmental Matters

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

Regional Haze Rules. APS has received the final rulemaking imposing pollution control requirements on Four Corners. EPA required the plant to install pollution control equipment that constitutes best available retrofit technology ("BART") to lessen the impacts of emissions on visibility surrounding the plant. Based on EPA's final standards, APS's 63% share of the cost of required controls for Four Corners Units 4 and 5 was approximately $400 million, which has been incurred.

In addition, EPA issued a final rule for Regional Haze compliance at Cholla that does not involve the installation of new pollution controls and that will replace an earlier BART determination for this facility. See "Cholla" in Note 4 for information regarding future plans for Cholla and details related to the resulting regulatory asset and see "Four Corners SCR Cost Recovery" above regarding recovery of the Four Corners SCR project.

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

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- Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to either authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. Although ADEQ has taken steps to develop a CCR permitting program, including the proposal of new state legislation providing ADEQ with appropriate permitting authority for CCR under the state solid waste management program, it is not clear when that program will be put into effect. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits. The proposal remains pending.

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

- 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 July 29, 2020, final regulation adopted this proposal and now requires explicit EPA approval for facilities to utilize an alternative closure deadline. With respect to the Cholla facility, APS's application for alternative closure (which would allow the continued disposal of CCR within the facility's existing unlined CCR surface impoundments until the required date for ceasing coal-fired boiler operations in April 2025) was submitted to EPA on November 30, 2020, and is currently pending. This application will be subject to public comment and, potentially, judicial review. EPA began taking action on these applications in January 2022, deeming APS's application for the Cholla facility "complete." We expect to have a proposed decision from EPA regarding Cholla later in 2022.

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

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $30 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $16 million. The Navajo Plant disposed of CCR only in a dry landfill storage area. To comply with the CCR rule for the Navajo Plant, APS's share of incremental costs was approximately $1 million, which has been incurred. Additionally, the CCR rule requires ongoing, phased groundwater monitoring.

As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must have ceased operating and initiated closure by April 11, 2021, at the latest (except for those disposal units subject to alternative closure). APS completed the assessments of corrective measures on June 14, 2019; however, additional investigations and engineering analyses that will support the remedy selection are still underway. In addition, APS will also solicit input from the public and host public hearings as part of this process. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from $10 million to $15 million, which would be incurred over 30 years. The analysis needed to perform a similar cost estimate for Cholla remains ongoing at this time.

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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.

EPA Climate Regulations. On June 19, 2019, EPA took final action on its proposals to repeal EPA's 2015 Clean Power Plan ("CPP") and replace those regulations with a new rule, the Affordable Clean Energy ("ACE") regulations. EPA originally finalized the CPP on August 3, 2015, and such rules would have had far broader impact on the electric power sector than the ACE regulations. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new existing power plant carbon regulations consistent with the court's ruling. That ruling endorsed an expansive view of the federal Clean Air Act consistent with EPA's 2015 CPP. On October 29, 2021, the U.S. Supreme Court announced that it was accepting judicial review of the January 2021 D.C. Circuit decision vacating the ACE regulations. A decision from the U.S. Supreme Court is expected during the summer of 2022. While the Biden administration has expressed an intent to regulate carbon emissions in this sector more aggressively under the Clean Air Act, we cannot at this time predict the outcome of pending EPA rulemaking proceedings or ongoing litigation related to the scope of EPA's authority under the Clean Air Act to regulate carbon emissions from existing power plants.

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

Four Corners National Pollutant Discharge Elimination System ("NPDES") Permit

The latest NPDES permit for Four Corners was issued on September 30, 2019. Based upon a November 1, 2019, filing by several environmental groups, the Environmental Appeals Board ("EAB") took up review of the Four Corners NPDES Permit. Oral argument on this appeal was held on September 3, 2020, and the EAB denied the environmental group petition on September 30, 2020. While the environmental groups had filed a petition for review of the EAB's decision with the U.S. Court of Appeals for the Ninth Circuit, on May 2, 2022, the parties to the litigation executed a settlement agreement. We do not anticipate that this agreement 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 purchased this 7% interest on July 3, 2018, from 4CA. 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. The note is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement. As of March 31, 2022, the note has a remaining balance of $4.6 million. NTEC continues to make payments in accordance with the terms of the note. Due to its short-remaining term, among other factors, there are no expected credit losses associated with the 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.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support commodity contract collateral obligations and other transactions. As of March 31, 2022, standby letters of credit totaled $8 million and expire in 2023. As of March 31, 2022, surety bonds expiring through 2023 totaled $6 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 March 31, 2022. In connection with the sale of 4CA's 7% interest to NTEC, Pinnacle West is guaranteeing certain obligations that NTEC will have to the other owners of Four Corners. (See "Four Corners — 4CA Matter" above for information related to this guarantee). Pinnacle West has not needed to perform under this guarantee. A maximum obligation is not explicitly stated in the guarantee and, therefore, the overall maximum amount of the obligation under such guarantee cannot be reasonably estimated; however, we consider the fair value of this guarantee, including expected credit losses, to be immaterial.

In connection with BCE's acquisition of minority ownership positions in the Clear Creek 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 are reduced as payments are made under the respective guarantee agreements. The Equity Contribution Guarantees remaining as of March 31, 2022, are immaterial in amount and the PTC Guarantees (approximately $36 million as of March 31, 2022) are currently expected to be terminated ten years following the commercial operation date of the applicable project.

In connection with the credit agreement entered into by a special purpose subsidiary of BCE on February 11, 2022, Pinnacle West has guaranteed the full amount of the equity bridge loan under the credit facility. See Note 3 for additional details.

9. Other Income and Other Expense

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

	Three Months Ended March 31,	
	2022	2021
Other income:		
Interest income	$ 1,642	$ 1,948
Debt return on Four Corners SCR deferrals (Note 4)	—	4,086
Debt return on Ocotillo modernization project (Note 4)	—	6,392
Miscellaneous	62	3
Total other income	$ 1,704	$ 12,429
Other expense:		
Non-operating costs	(2,453)	(1,937)
Investment losses — net	(681)	(343)
Miscellaneous	(288)	(1,573)
Total other expense	$ (3,422)	$ (3,853)

The following table provides detail of APS's other income and other expense (dollars in thousands):

	Three Months Ended March 31,	
	2022	2021
Other income:		
Interest income	$ 1,099	$ 1,481
Debt return on Four Corners SCR deferrals (Note 4)	—	4,086
Debt return on Ocotillo modernization project (Note 4)	—	6,392
Miscellaneous	53	1
Total other income	$ 1,152	$ 11,960
Other expense:		
Non-operating costs	(1,561)	(1,778)
Miscellaneous	(288)	(1,572)
Total other expense	$ (1,849)	$ (3,350)

10. Earnings Per Share

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

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
Net income attributable to common shareholders	$ 16,956	$ 35,641
Weighted average common shares outstanding — basic	113,102	112,829
Net effect of dilutive securities:		
Contingently issuable performance shares and restricted stock units	193	264
Weighted average common shares outstanding — diluted	113,295	113,093
Earnings per weighted-average common share outstanding		
Net income attributable to common shareholders — basic	$ 0.15	$ 0.32
Net income attributable to common shareholders — diluted	$ 0.15	$ 0.32

11. Fair Value Measurements

We classify our assets and liabilities that are carried at fair value within the fair value hierarchy. This hierarchy ranks the quality and reliability of the inputs used to determine fair values, which are then classified and disclosed in one of three categories. The three levels of the fair value hierarchy are:

Level 1 — Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date.

Level 2 — Other significant observable inputs, including quoted prices in active markets for similar assets or liabilities; quoted prices in markets that are not active, and model-derived valuations whose inputs are observable (such as yield curves).

Level 3 — Valuation models with significant unobservable inputs that are supported by little or no market activity. Instruments in this category may include long-dated derivative transactions where valuations are unobservable due to the length of the transaction, options, and transactions in locations where observable market data does not exist. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices.

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

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

Recurring Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, and investments held in the nuclear decommissioning trusts and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefit plans. See Note 8 in the 2021 Form 10-K 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.

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Investments Held in Nuclear Decommissioning Trusts and Other Special Use Funds

The nuclear decommissioning trusts and other special use funds invest in fixed income and equity securities. Other special use funds include the coal reclamation escrow account and the active union employee medical account. See Note 12 for additional discussion about our investment accounts.

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

Fixed Income Securities

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

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

Equity Securities

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

The nuclear decommissioning trusts and other special use funds may also hold equity securities that include exchange traded mutual funds and money market accounts for short-term liquidity purposes. These short-term, highly-liquid, investments are valued using active market prices.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Fair Value Tables

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

	Level 1	Level 2	Level 3	Other		Total
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 296,442	$ 9,802	$ (8,621)	(a)	$ 297,623
Nuclear decommissioning trust:						
Equity securities	16,787	—	—	478	(b)	17,265
U.S. commingled equity funds	—	—	—	567,950	(c)	567,950
U.S. Treasury debt	225,902	—	—	—		225,902
Corporate debt	—	196,300	—	—		196,300
Mortgage-backed securities	—	145,845	—	—		145,845
Municipal bonds	—	65,494	—	—		65,494
Other fixed income	—	8,709	—	—		8,709
Subtotal nuclear decommissioning trust	242,689	416,348	—	568,428		1,227,465
Other special use funds:						
Equity securities	27,068	—	—	1,112	(b)	28,180
U.S. Treasury debt	312,613	—	—	—		312,613
Municipal bonds		8,249	—	—		8,249
Subtotal other special use funds	339,681	8,249	—	1,112		349,042
Total assets	$ 582,370	$ 721,039	$ 9,802	$ 560,919		$ 1,874,130
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ —	$ (152)	$ (1,554)	(a)	$ (1,706)

(a) Represents counterparty netting, margin, and collateral. See Note 7.
(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 CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

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

(a) Represents counterparty netting, margin, and collateral. See Note 7.
(b) Represents net pending securities sales and purchases.
(c) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

Fair Value Measurements Classified as Level 3

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

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 3 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 $4.6 million as of March 31, 2022, as presented on the Condensed 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 8 for more information on 4CA matters.

12. Investments in Nuclear Decommissioning Trusts and Other Special Use Funds

We have investments in debt and equity securities held in Nuclear Decommissioning Trusts, Coal Reclamation Escrow Account, and an Active Union Employee Medical Account. Investments in debt securities are classified as available-for-sale securities. We record both debt and equity security investments at their fair value on our Condensed Consolidated Balance Sheets. See Note 11 for a discussion of how fair value is determined and the classification of the investments within the fair value hierarchy. The investments in each trust or account are restricted for use and are intended to fund specified costs and activities as further described for each fund below.

Nuclear Decommissioning Trusts — APS established external decommissioning trusts in accordance with NRC regulations to fund the future costs APS expects to incur to decommission Palo Verde. Third-party investment managers are authorized to buy and sell securities per stated investment guidelines. The trust funds are invested in fixed income securities and equity securities. Earnings and proceeds from sales and maturities of securities are reinvested in the trusts. Because of the ability of APS to recover decommissioning costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including credit losses) in other regulatory liabilities.

Coal Reclamation Escrow Account — APS has investments restricted for the future coal mine reclamation funding related to Four Corners. This escrow account is primarily invested in fixed income securities. Earnings and proceeds from sales of securities are reinvested in the escrow account. Because of the ability of APS to recover coal reclamation costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including credit losses) in other regulatory liabilities. Activities relating to APS coal mine reclamation escrow account investments are included within the other special use funds in the table below.

Active Union Employee Medical Account — APS has investments restricted for paying active union employee medical costs. These investments may be used to pay active union employee medical costs incurred in the current and future periods. In 2021, APS 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 credit losses) in other regulatory liabilities. Activities relating to active union employee medical account investments are included within the other special use funds in the table below.

APS

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

	March 31, 2022					
	Fair Value					
Investment Type:	**Nuclear Decommissioning Trusts**	**Other Special Use Funds**	**Total**		**Total Unrealized Gains**	**Total Unrealized Losses**
Equity securities	$ 584,737	$ 27,068	$ 611,805		$ 422,497	$ (37)
Available for sale-fixed income securities	642,250	320,862	963,112	(a)	8,653	(36,962)
Other	478	1,112	1,590	(b)	—	—
Total	$ 1,227,465	$ 349,042	$ 1,576,507		$ 431,150	$ (36,999)

(a) As of March 31, 2022, the amortized cost basis of these available-for-sale investments is $991 million.
(b) Represents net pending securities sales and purchases.

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

(a) As of December 31, 2021, the amortized cost basis of these available-for-sale investments is $972 million.
(b) Represents net pending securities sales and purchases.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	Three Months Ended March 31,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2022			
Realized gains	$ 1,023	$ —	$ 1,023
Realized losses	(7,235)	—	(7,235)
Proceeds from the sale of securities (a)	319,693	41,545	361,238
2021			
Realized gains	$ 2,968	$ —	$ 2,968
Realized losses	(4,148)	—	(4,148)
Proceeds from the sale of securities (a)	234,728	145,250	379,978

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

Fixed Income Securities Contractual Maturities

The fair value of APS's fixed income securities, summarized by contractual maturities, at March 31, 2022, is as follows (dollars in thousands):

	Nuclear Decommissioning Trusts	Coal Reclamation Escrow Account	Active Union Employee Medical Account	Total
Less than one year	$ 18,119	$ 41,906	$ 40,463	$ 100,488
1 year – 5 years	198,233	35,749	151,838	385,820
5 years – 10 years	139,957	1,749	44,205	185,911
Greater than 10 years	285,941	4,952	—	290,893
Total	$ 642,250	$ 84,356	$ 236,506	$ 963,112

13. Changes in Accumulated Other Comprehensive Loss

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

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Three Months Ended March 31					
Balance December 31, 2021	$ (53,885)		$ (976)		$ (54,861)
OCI before reclassifications	—		252		252
Amounts reclassified from accumulated other comprehensive loss	901	(a)	—	(b)	901
Balance March 31, 2022	$ (52,984)		$ (724)		$ (53,708)
Balance December 31, 2020	$ (60,725)		$ (2,071)		$ (62,796)
OCI before reclassifications	—		262		262
Amounts reclassified from accumulated other comprehensive loss	1,022	(a)	—	(b)	1,022
Balance March 31, 2021	$ (59,703)		$ (1,809)		$ (61,512)

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 5.

(b) These amounts primarily 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 7.

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

	Pension and Other Postretirement Benefits		Total
Three Months Ended March 31			
Balance December 31, 2021	$ (34,880)		$ (34,880)
Amounts reclassified from accumulated other comprehensive loss	820	(a)	820
Balance March 31, 2022	$ (34,060)		$ (34,060)
Balance December 31, 2020	$ (40,918)		$ (40,918)
Amounts reclassified from accumulated other comprehensive loss	927	(a)	927
Balance March 31, 2021	$ (39,991)		$ (39,991)

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 5.

ITEM 2. 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 Condensed Consolidated Financial Statements and APS's Condensed Consolidated Financial Statements and the related Combined Notes that appear in Item 1 of this report. 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 Part 1, Item 1A of the 2021 Form 10-K, and Part II, Item 1A of this report.

OVERVIEW

Business Overview

Pinnacle West is an investor-owned electric utility holding company based in Phoenix, Arizona with consolidated assets of about $22 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.

COVID-19 Pandemic

Essential planned work and capital investments have continued during the COVID-19 pandemic with priority given to support fire mitigation and summer storm efforts, as well as heat related outages. Raw material shortages, rising inflation, COVID-19 related work force disruptions and natural disasters are putting increased pressure on the global supply chain. APS is experiencing some delays in finished materials and tight labor markets. To date, APS has not experienced labor or material supply chain shortages that have significantly impacted its ability to serve its customers' needs. However, shortages are causing some delays, and shifting of work projects based on material availability. If APS continues to experience delays in materials, it could experience an increase in purchased power costs for summer generation needs. Such increased purchased power costs would be expected to be recoverable through the PSA. See Note 4 for additional information on the PSA. APS has measures in place to continually monitor and evaluate resource needs and supply chain adequacy but cannot predict whether there will be material supply chain shortages in the future.

Though the total expected impact of COVID-19 on future sales remains unknown, APS experienced higher electric residential sales and lower electric commercial and industrial sales from the outset of the pandemic through April 2021. Beginning in May 2021, electric sales to commercial and industrial customers increased to levels in line with pre-COVID sales and such sales levels have remained to date.

The Coronavirus Aid, Relief, and Economic Security (CARES) Act allowed employers to defer payments of the employer share of Social Security payroll taxes that would have otherwise been owed from March 27, 2020, through December 31, 2020. We deferred the cash payment of the employer's portion of Social Security payroll taxes for the period July 1, 2020, through December 31, 2020, which was approximately $18 million. We paid half of this cash deferral by December 31, 2021, and the remainder will be paid by December 31, 2022.

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

Strategic Overview

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

Clean Energy Commitment

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

APS's clean energy goals consist of three parts:

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

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

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

2030 Goal: 65% Clean Energy. APS has an energy mix that is already 50% clean with existing plans to add more renewables and energy storage before 2025. By building on those plans, APS intends to attain an energy mix that is 65% clean by 2030, with 45% of APS's generation portfolio coming from renewable energy. "Clean" is measured as percent of energy mix which includes all carbon-free resources like nuclear and demand-side management, and "renewable" is expressed as a percent of retail sales. This target will serve as a checkpoint for our resource planning, investment strategy, and customer affordability efforts as APS moves toward 100% clean, carbon-free energy mix by 2050.

2031 Goal: End APS's Use of Coal-Fired Generation. The commitment to end APS's use of coal-fired generation by 2031 will require APS to cease use of coal-generation at Four Corners. APS has permanently retired more than 1,000 MW of coal-fired electric generating capacity. These closures and other measures taken by APS have resulted in a total reduction of carbon emissions of 33% since 2005. In addition, APS has committed to end the use of coal at its remaining Cholla units by 2025.

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

Consistent with the 2019 Rate Case decision, as of April 2022, APS has completed the following payments that will be recoverable through rates related to the CCT: (i) \$3.33 million to the Navajo Nation; (ii) \$500,000 to the Navajo County communities; and (iii) \$1 million to the Hopi Tribe. Consistent with APS's commitment to the impacted communities, APS has also completed the following payments: (i)\$500,000 to the Navajo Nation for electrification; (ii) \$1.1 million to the Navajo County Communities for CCT and economic development; and (iii) \$1.25 million to the Hopi Tribe for CCT and economic development. The ACC has also authorized \$1.25 million to be recovered through rates for electrification of homes and businesses on both the Navajo Nation and Hopi reservation. Expenditure of these funds is contingent upon completion of a census of the unelectrified homes and businesses within APS service territory on both the Navajo Nation and Hopi reservation.

In June 2021, APS and the owners of Four Corners entered into agreements to operate Four Corners seasonally beginning in fall 2023, subject to the necessary governmental approvals and conditions associated with changes in plant ownership. Under seasonal operation, a single unit will remain online year-round, subject to market conditions as well as planned maintenance outages and unplanned outages. In addition, the other unit will be operational throughout the summer season of June through October when customer demand is the highest. APS believes that operating Four Corners seasonally will bring environmental benefits and ensure continued service reliability for its customers, especially during Arizona's hot summer months, as APS transitions to ceasing to use coal-fired generation by 2031. By moving to seasonal operations, Four Corners will become a more flexible resource that supports increasing amounts of clean energy, helping to compensate for the intermittent output of renewable resources. This change also helps ensure reliability of a critical energy source while reducing operations and maintenance costs. APS estimates that the shift to seasonal operations will reduce annual carbon emissions at Four Corners by an estimated 20-25%, as compared to current conditions.

Renewables. APS's IRP (see Note 4 for additional information) establishes the path to meeting our clean energy commitment and maintaining reliable electric service for our customers. APS intends to strengthen its already diverse energy mix by increasing its investments in carbon-free resources. Our IRP rapidly adds clean energy and storage resources while maintaining reliable and affordable service. Its near-term actions are focused on clean energy and positive customer outcomes and includes: (a) competitive solicitations to procure clean energy resources such as solar, wind, energy storage, and DSM resources, all of which lead to a cleaner grid; and (b) strategic, short-term wholesale market purchases from a combination of existing merchant natural gas units, neighboring utility systems and wholesale market participants that ensure operational reliability.

APS has a diverse portfolio of existing and planned renewable resources, including solar, wind, geothermal, biomass and biogas, that supports our commitment to clean energy. That commitment has its foundation in the Palo Verde generating station, which is the nation's largest carbon-free, clean energy resource, and it provides critical reliable and affordable service for APS customers. APS's longer-term clean energy strategy includes pursuing the right mix of purchased power contracts for new facilities, procurement of new facilities to be owned by APS, and the ongoing development of distributed energy resources. This balance will ensure an appropriately diverse portfolio designed to achieve the same operational reliability and customer affordability as APS's near-term strategies. In addition, APS is actively seeking to include future facility purchase options in its PPAs that will enable investments with greater financial flexibility.

APS uses competitive "all source" requests for proposal ("RFPs") to pursue market resources that meet its system needs and offer the best value for customers. APS selects projects based on cost and non-cost factors, taking into consideration timing and likelihood of successful contracting and development. Under current market conditions, APS must aggressively contract for resources that can withstand supply chain and other geopolitical pressures. Available projects are guided by IRP timelines and quantities and APS maintains a flexible approach that allows it to optimize system reliability and customer affordability through the RFP process. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the projects to the electric grid. See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Current and Future Resources — Renewable Energy Standard — Renewable Energy Portfolio" in Item 1 for details regarding APS's renewable energy resources.

In September 2019, APS issued an RFP that requested up to 250 MW of wind resources to be in service as soon as possible, but no later than 2022. As a result of this RFP, APS executed a 200 MW PPA for a wind resource that went into service in January 2022. In December 2020, APS issued two additional RFPs: (i) a battery storage RFP for projects to be located at two AZ Sun sites; and (ii) an all-source RFP that solicited resources to meet our clean energy needs and capacity to maintain system reliability, and was later amended to include a request for 150 MW of solar resources to be developed on APS property and owned by APS (collectively, the "December 2020 RFPs"). As a result of the all-source RFP, APS executed a PPA in October 2021 for a 238 MW wind resource to be in service by June 2023, and also executed an engineering, procurement, and construction contract in November 2021 for a 150 MW solar resource to be owned by APS and in service in early 2023. APS continues to negotiate contracts for additional resources to be in service in 2024 in connection with the all-source RFP. Once it secures those important resources and closes out the December 2020 RFPs, APS intends to issue its next all source RFP to address resource needs for 2025 and beyond.

The following table summarizes the resources in APS's renewable energy portfolio that are in operation and under development as of March 31, 2022. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the projects to the electric grid.

	Net Capacity in Operation (MW)	Net Capacity Planned / Under Development (MW)	
Total APS Owned: Solar	248	150	
Purchased Power Agreements Renewables:			
Solar	310	435	
Wind	399	238	
Geothermal	10	—	
Biomass	14	—	
Biogas	3	—	
Total Purchased Power Agreements	736	673	
Total Distributed Energy: Solar (a)	1,281	82	(b)
Total Renewable Portfolio	2,265	905	

(a) Includes rooftop solar facilities owned by third parties. Distributed generation is produced in Direct Current and is converted to Alternating Current for reporting purposes.
(b) Applications received by APS that are not yet installed and online.

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

In 2018, APS issued an RFP for approximately 106 MW of energy storage to be located at up to five of its AZ Sun sites. Based upon its evaluation of the RFP responses, APS decided to expand the initial phase of battery deployment to 141 MW by adding a sixth AZ Sun site. These battery storage facilities are expected to be in service during the summer of 2022. On August 2, 2021, APS executed a contract for an additional 60 MW of utility-owned energy storage to be located on APS's AZ Sun sites. This contract, with a 2023 in-service date, will complete the addition of storage on current APS-owned utility-scale solar facilities.

Additionally, in February 2019, APS signed two 20-year PPAs for energy storage totaling 150 MW. These PPAs were subject to ACC approval in order to allow for cost recovery through the PSA. APS received the requested ACC approval on January 12, 2021, and service under the agreements is expected to begin in 2022 with respect to 100 MW and in 2023 with respect to 50 MW.

As a result of its December 2020 RFPs, as of May 2022, APS has executed four 20-year PPAs for resources that include energy storage: (a) two PPAs for standalone energy storage resources totaling 300 MW; and (b) two PPAs totaling 275 MW solar plus storage resource. The PPAs are also subject to ACC approval to enable cost recovery through the PSA. APS received the requested ACC approval for three out of four of the projects on December 16, 2021. The remaining project was filed in February 2022 for ACC approval and on

April 13, 2022, the ACC approved this application. Service under the agreements is expected to begin in 2023 and 2024.

APS currently plans to install more than 900 MW of energy storage by 2025, including the energy storage projects under PPAs and AZ Sun retrofits described above. The remaining energy storage is expected to be made up of resources solicited through current and future RFPs.

The following table summarizes the resources in APS's energy storage portfolio that are in operation and under development as of March 31, 2022. Agreements for the development and completion of future resources are subject to various conditions.

	Net Capacity in Operation (MW)	Net Capacity Planned / Under Development (MW)
APS Owned: Energy Storage	—	201
Purchase Power Agreements - Energy Storage	—	725
Residential Energy Storage	13(a)	3
Total Energy Storage Portfolio	**13**	**929**

(a) This includes 13.1 MW of APS customer-owned batteries and 0.2 MW of APS-owned residential batteries.

Palo Verde. Palo Verde, the nation's largest carbon-free, clean energy resource, will continue to be a foundational part of APS's resource portfolio. The plant currently 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 is a critical asset to the Southwest, generating more than 32 million megawatt-hours annually – enough power for more than 4 million people. Its continued operation is important to a carbon-free and clean energy future for Arizona and the region, as a reliable, continuous, affordable resource and as a large contributor to the local economy.

Affordable

We believe it is APS's responsibility to deliver electric services to customers in the most cost-effective manner. Since January 2018 through March 2022, the average residential bill decreased by 1.44%, or $2.12, due to net reductions in cost recovery adjustor mechanisms.

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 internal efficiencies. In 2021, APS continued to drive this initiative by identifying opportunities to streamline its business processes and deliver sustainable cost savings, which resulted in the Company identifying approximately $30 million in annual incremental cost saving opportunities in 2022. APS is continuing this initiative in 2023.

Participation in the Energy Imbalance Market ("EIM") continues to be a tool for creating savings for APS's customers from the real-time, voluntary market. APS continues to expect that its participation in EIM will lower its fuel and purchased-power costs, improve situational awareness for system operations in the Western Interconnection power grid, and improve integration of APS's renewable resources. APS continues to evaluate opportunities that benefit our customers and is exploring opportunities to move to a day-ahead market with the expectation of reliably achieving incrementally greater cost savings and using the region's increasing renewable resources more efficiently. As part of that effort, APS is exploring several options. APS is in discussions with the current EIM operator, the CAISO, the Western Resource Adequacy Program, the Western Markets Exploratory Group, and the Southwest Power Pool. Each of these explorations also involve other entities and are being undertaken to evaluate the feasibility and cost/benefit of creating a voluntary day-ahead market.

Reliable

While our energy mix evolves, the obligation to deliver reliable service to our customers remains. Notwithstanding the challenges presented by the COVID-19 pandemic, as well the Phoenix metropolitan experiencing the warmest June on record and its summer monsoon being the third wettest over the last 41 years, APS continued to provide reliable service to its customers in 2021.

Planned investments will support operating and maintaining the grid, updating technology, accommodating customer growth, and enabling more renewable energy resources. Our advanced distribution management system allows operators to locate outages, control line devices remotely and helps them coordinate more closely with field crews to safely maintain an increasingly dynamic grid. The system also integrates a new meter data management system that increases grid visibility and gives customers access to more of their energy usage data.

Wildfire safety remains a critical focus for APS and other utilities. We increased investment in fire mitigation efforts to clear defensible space around our infrastructure, continue ongoing system upgrades, build partnerships with government entities and first responders and educate customers and communities. These programs contribute to customer reliability, responsible forest management and safe communities.

The new units at our modernized Ocotillo Power Plant provide cleaner-running and more efficient units. They support reliability by responding quickly to the variability of solar generation and delivering energy in the late afternoon and early evening when solar production declines as the sun sets and customer demand peaks.

In April 2021, the CAISO sought FERC authorization for certain tariff changes intended to try to address risks associated with high heat weather events. Although APS is generally supportive of some of these changes, others would change the load, export, and wheeling priorities in a way that would unfairly benefit California entities at the expense of non-California entities. On June 25, 2021, FERC issued an order accepting the CAISO's proposed changes. On July 26, 2021, APS filed seeking a rehearing of FERC's June 25, 2021 order. On August 26, 2021, FERC issued a notice indicating that the pending requests for rehearing were denied by operation of law and providing for further consideration. On March 15, 2022, FERC issued an order addressing the arguments raised on rehearing, denying clarification, and dismissing the rehearing request.

In October of 2021, APS announced plans to evaluate regional market solutions as part of the informal Western Markets Exploratory Group ("WMEG"). As part of WMEG, APS is exploring the potential for a staged approach to new market services, including day-ahead energy sales, transmission system expansion, and other power supply and grid solutions consistent with existing state regulations. WMEG hopes to identify market solutions that can help achieve carbon reduction goals while supporting reliable, affordable service for customers. APS is unable to predict the outcome of these discussions.

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

Customer-Focused

Recognizing that creating customer value is inextricably linked to increasing shareholder value, APS's focus remains on its customers and the communities it serves. Accordingly, it is APS's goal to achieve an industry-leading, best-in-class customer experience, while demonstrating compassion and advocacy for its customers. This multi-year objective includes incrementally improving APS's J.D. Power ("JDP") overall customer satisfaction ratings from the fourth quartile to the first quartile of its peer set comprised of large investor-owned utilities.

APS's JDP residential overall customer satisfaction rating improved in the fourth quarter of 2021, ranking in the third quartile. That improvement trend continued with the latest JDP residential 2022 first-quarter results. APS made quartile gains in every single driver of customer satisfaction with APS moving into the top half of the third quartile for overall satisfaction when compared to its large investor-owned peers. APS's strongest performing drivers in the latest JDP survey were Power Quality and Reliability and Customer Care, both of which performed well above the large investor-owned peer set averages.

Developing Clean Energy Technologies

Electric Vehicles

APS is making electric vehicle charging more accessible for its customers and helping Arizona businesses, schools and governments electrify their fleets. In 2021, APS continued its expansion of its Take Charge AZ Pilot Program. As of year-end 2021, APS had installed over 400 charging ports at customer locations with more stations expected to be added through 2022. The program provides charging equipment, installation, and maintenance to business customers, government agencies, non-profits, and multifamily housing communities. In addition to the Level 2 charging stations, APS has begun construction of DC fast charging stations that will be owned and operated by APS at five locations in Arizona, with the first location that opened in March 2022. The other four projects' locations are expected to be completed during 2022, with each location including 2-150 kilowatt and 2-350 kilowatt DC fast charging ports. Charging at these stations will be accessible through the Electrify America charging network. APS also has a goal of 450,000 light-duty electric vehicles in its service territory by 2030.

Additionally, as part of APS's DSM plan, APS has launched an Electric Vehicle Charging Demand Management Pilot Program to proactively address the growing electric demand from electric vehicle charging as electric vehicles become more widely adopted. This program includes the APS SmartCharge data gathering program, an electric vehicle smart charger rebate for qualifying electric vehicle chargers, and a $100 rebate to home builders for new home 240V charging station garage outlets.

The ACC ordered the state's public service corporations, including APS, to develop a long-term, comprehensive Statewide Transportation Electrification Plan ("TE Plan") for Arizona. The TE Plan is intended to provide a roadmap for Transportation Electrification in Arizona, focused on realizing the associated air quality and economic development benefits for all residents in the state along with understanding the impact of electric vehicle charging on the grid. APS actively participated in developing this plan. The ACC approved the plan in December 2021. APS recently filed its first TE Plan Annual Progress Report to the ACC and is currently working with stakeholders to develop a budget and implementation plan for ACC review later this year.

Hydrogen Production

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

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

Carbon Capture

Carbon capture technologies can isolate CO_2 and either sequester it permanently in geologic formations or convert it for use in products. Currently, almost all existing fossil fuel generators do not control carbon emissions the way they control emissions of other air pollutants such as sulfur dioxide or oxides of nitrogen. Carbon capture technologies are still in the demonstration phase and while they show promise, they are still being tested in real-world conditions. These technologies could offer the potential to keep in operation existing generators that otherwise would need to be retired. APS will continue to monitor this emerging technology.

Environmental, Social, and Governance ("ESG") Practices

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

As a first step, the Company engaged the Electric Power Research Institute ("EPRI") and leveraged input from employees, large customers, limited-income advocates, economic development groups, environmental non-governmental organizations, leading sustainability academics and other stakeholders to identify and assess the sustainability issues that matter most. In total, 23 Priority Sustainability Issues ("PSIs") were identified and prioritized. The most critical category, Integral Shared Value, includes four issues deemed most important and most able to be impacted by our actions: clean energy, customer experience, energy access and reliability and safety and health. These Integral PSIs provide the foundation for informing our strategic direction, creating a framework for incorporating best practices and driving enterprise-wide alignment and accountability. In 2021, the Company engaged EPRI for the second phase of this work, focused on benchmarking best practices within these four Integral Shared Value PSIs. We will utilize the benchmarking information to identify opportunities for further improvement in our ESG performance.

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

In 2021, the Company finalized an ESG Strategic Framework to guide our work. The framework is based upon three foundational pillars: ESG Policy Advocacy (we advocate for policy that supports our clean energy goals); Driving Performance (improving our ESG performance in the most important areas, including our PSIs); and effectively communicating and amplifying our ESG story to our various stakeholders, including investors, customers, employees and beyond. The framework will guide and shape our ESG work moving forward.

Regulatory Overview

On October 31, 2019, APS filed an application with the ACC (the "2019 Rate Case") seeking an increase in annual retail base rates of $69 million. This amount includes recovery of the deferral and rate base effects of the Four Corners SCR project that was the subject of a separate proceeding. See "Four Corners 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 annual revenue increase in APS's application is $184 million. The average annual customer bill impact of APS's request is an increase of 5.6% (the average annual bill impact for a typical APS residential customer is 5.4%).

The principal provisions of APS's application were:

- a test year comprised of 12 months ended June 30, 2019, adjusted as described below;
- an original cost rate base of $8.87 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	45.3 %	4.1 %
Common stock equity	54.7 %	10.15 %
Weighted-average cost of capital		7.41 %

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- a Base Fuel Rate of $0.030168 per kWh;
- 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 Note 4 for a 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.

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

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

The CCT plan includes the following proposed components: (i) $100 million that will be paid over 10 years to the Navajo Nation for a sustainable transition to a post-coal economy, which would be funded by customers, (ii) $1.25 million that will be paid over five years to the Navajo Nation to fund an economic development organization, which would be funds not recoverable through rates, (iii) $10 million to facilitate electrification projects within the Navajo Nation, which would be funded equally by funds not recoverable through rates and by customers, (iv) $2.5 million per year in transmission revenue sharing to be paid to the Navajo Nation beginning after the closure of the Four Corners through 2038, which would be funds not recoverable through rates, (v) $12 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, which would primarily be funded by customers, and (vi) $3.7 million that will be paid over five years to the Hopi Tribe related to APS's ownership interests in the Navajo Plant, which would primarily be funded by customers. In 2021, APS committed an additional $900,000 to be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant.

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

On August 2, 2021, the Administrative Law Judge issued a Recommended Opinion and Order in the 2019 Rate Case (the "2019 Rate Case ROO") and issued corrections on September 10 and September 20, 2021. The 2019 Rate Case ROO recommended, among other things, (i) a $111 million decrease in annual revenue requirements, (ii) a return on equity of 9.16%, (iii) a 0.30% return on the increment of fair value rate base greater than original cost, with total fair value rate of return further adjusted to include a 0.03% reduction to return on equity resulting in an effective fair value rate of return of 4.95%, (iv) the nonrecovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project (see "Four Corners SCR Cost Recovery" below for additional information), (v) the recovery of the deferral and rate base effects of the operating costs and construction of the Ocotillo modernization project, which includes a reduction in the return on the deferral, (vi) a 15% disallowance of annual amortization of Navajo Plant regulatory asset recovery, (vii) the denial of the request to defer until APS's next general rate case the increase or decrease in its Arizona property taxes attributable to tax rate changes, and (viii) a collaborative process to review and recommend revisions to APS's adjustment mechanisms within 12 months after the date of the decision. The 2019 Rate Case ROO also recommended that the CCT plan include the following components: (i) $50 million that will be paid over 10 years to the Navajo Nation, (ii) $5 million that will be paid over five years to the Navajo County Communities surrounding Cholla Power Plant, and (iii) $1.675 million that will be paid to the Hopi Tribe related to APS's ownership interests in the Navajo Plant. These amounts would be recoverable from APS's customers through the RES adjustment mechanism. APS filed exceptions on September 13, 2021, regarding the disallowance of the SCR cost deferrals and plant investments that was recommended in the 2019 Rate Case ROO, among other issues.

On October 6, 2021 and October 27, 2021, the ACC voted on various amendments to the 2019 Rate Case ROO that would result in, among other things, (i) a return on equity of 8.70%, (ii) the recovery of the deferral and rate base effects of the operating costs and construction of the Four Corners SCR project, with the exception of $215.5 million (see "Four Corners SCR Cost Recovery" below), (iii) that the CCT plan include the following components: (a) a payment of $1 million to the Hopi Tribe within 60 days of the 2019 Rate Case decision, (b) a payment of $10 million over three years to the Navajo Nation, (c) a payment of $500,000 to the Navajo County communities within 60 days of the 2019 Rate Case decision, (d) up to $1.25 million for electrification of homes and businesses on the Hopi reservation and (e) up to $1.25 million for the electrification of homes and businesses on the Navajo Nation reservation. These payments and expenditures are attributable to the future closures of Four Corners and Cholla, along with the prior closure of the Navajo Plant and all ordered payments and expenditures would be recoverable through rates, and (iv) a change in the residential on-peak time-of-use period from 3 p.m. to 8 p.m. to 4 p.m. to 7 p.m. Monday through Friday, excluding holidays. The 2019 Rate Case ROO, as amended, results in a total annual revenue decrease for APS of $4.8 million, excluding temporary CCT payments and expenditures. On November 2, 2021, the ACC approved the 2019 Rate Case ROO, as amended. On November 24, 2021, APS filed with the ACC an application for rehearing of the 2019 Rate Case and the application was deemed denied on December 15, 2021, as the ACC did not act upon it. On December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals and a Petition for Special Action with the Arizona Supreme Court, requesting review of the disallowance of $215 million of Four Corners SCR plant investments and deferrals (see "Four Corners SCR Cost Recovery" below for additional information) and the 20 basis point penalty reduction to the return on equity. On February 8, 2022, the Arizona Supreme Court declined to accept jurisdiction on APS's Petition for Special Action. The appeal at the Arizona Court of Appeals is proceeding in the normal course. APS cannot predict the outcome of this proceeding.

Consistent with the 2019 Rate Case decision, APS implemented the new rates effective as of December 1, 2021. On December 3, 2021, ACC Staff notified the ACC of a discrepancy between the written decision, which approved the change in time-of-use on-peak hours to 4 p.m. to 7 p.m. but did not explicitly approve the 10-months contemplated in APS's verbal testimony to implement the new time-of-use hours. On December 16, 2021, the ACC ordered APS to complete the implementation of the time-of-use peak period by

April 1, 2022. On January 12, 2022, the ACC voted to extend until September 1, 2022, the deadline to complete the implementation of the new on-peak hours for residential customers. In addition, the ACC ordered extensive compliance and reporting obligations and will be continuing to explore whether penalties or rebates would be owed to certain customers. APS cannot predict the outcome of this matter.

APS expects to file an application with the ACC for its next general retail rate case by mid-year 2022 but is continuing to evaluate the timing of such filing.

See Note 4 for information regarding additional regulatory matters.

Four Corners SCR Cost Recovery

As part of APS's 2019 Rate Case, APS included recovery of the deferral and rate base effects of the Four Corners SCR project. On November 2, 2021, the 2019 Rate Case decision was approved by the ACC allowing approximately $194 million of SCR related plant investments and cost deferrals in rate base and to recover, depreciate and amortize in rates based on an end-of-life assumption of July 2031. The decision also included a partial and combined disallowance of $215.5 million on the SCR investments and deferrals. APS believes the SCR plant investments and related SCR cost deferrals were prudently incurred, and on December 17, 2021, APS filed its Notice of Direct Appeal at the Arizona Court of Appeals requesting review of the $215.5 million disallowance and the appeal is proceeding in the normal course. Based on the partial recovery of these investments and cost deferrals in current rates and the uncertainty of the outcome of the legal appeals process, APS has not recorded an impairment or write-off relating to the SCR plant investments or deferrals as of March 31, 2022. If the 2019 Rate Case decision to disallow $215.5 million of the SCRs is ultimately upheld, APS will be required to record a charge to its results of operations, net of tax, of approximately $154.4 million. We cannot predict the outcome of the legal challenges nor the timing of when this matter will be resolved. See Note 4 for additional information regarding the Four Corners SCR cost recovery.

Financial Strength and Flexibility

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

Other Subsidiaries

Bright Canyon Energy. On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE's strategy is to develop, own, operate and acquire energy infrastructure in a manner that leverages the Company's core expertise in the electric energy industry. In 2014, BCE formed a 50/50 joint venture with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. The joint venture, named TransCanyon, is pursuing independent electric transmission opportunities within the 11 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 March 31, 2022, BCE had total assets of approximately $60 million.

BCE is in advanced development stage on a microgrid facility in Los Alamitos, California ("Los Alamitos") featuring 31 MW of solar, 20 MW of battery storage, and 3 MW of backup generators. Supported by a long-term power purchase agreement with San Diego Gas and Electric Company, Los Alamitos will supply 20 MW of solar and battery storage capacity to the Southern California grid and provide resilient backup power in the event of a grid emergency to the Army and California National Guard at Joint Forces

Training Base Los Alamitos. The Los Alamitos project is scheduled to achieve commercial operation in 2023. See Note 3 regarding a credit agreement entered into by BCE to finance capital expenditures and related costs for this microgrid project.

BCE and Ameresco, Inc. jointly own a special purpose entity that is sponsoring the Kūpono Solar project. This project is a 42 MW solar and battery storage facility in O'ahu, Hawaii that will supply clean renewable energy and capacity under a 20-year power purchase agreement with Hawaiian Electric Company, Inc. The Kūpono Solar project is expected to be completed in 2024.

El Dorado. El Dorado is a wholly-owned subsidiary of Pinnacle West. El Dorado owns debt investments and minority interests in several energy-related investments and Arizona community-based ventures. El Dorado committed to a $25 million investment in the Energy Impact Partners fund, which is an organization that focuses on fostering innovation and supporting the transformation of the utility industry. The investment will be made by El Dorado as investments are selected by the Energy Impact Partners fund. As of March 31, 2022, El Dorado has contributed approximately $10 million to the Energy Impact Partners fund. Additionally, El Dorado committed to a $25 million investment in invisionAZ Fund, which is a fund focused on analyzing, investing, managing and otherwise dealing with investments in privately held early stage and emerging growth technology companies and businesses primarily based in the State of Arizona, or based in other jurisdictions and having existing or potential strategic or economic ties to companies or other interests in the State of Arizona.

Key Financial Drivers

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

Electric Operating Revenues. For the years 2019 through 2021, retail electric revenues comprised approximately 94% of our total operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, distributed energy additions, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery mechanisms. 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 2.2% for the three-month period ended March 31, 2022, compared with the prior-year period. For the three years through 2021, APS's customer growth averaged 2.2% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2022, and the average annual growth will be in the range of 1.5% to 2.5% through 2024 based on anticipated steady population growth in Arizona during that period.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 4.4% for the three-month period ended March 31, 2022, compared with the prior-year period. While steady customer growth was somewhat offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives, the main drivers of positive sales for this period were residential sales being stronger than anticipated due to continued work-from-home policies, a strong improvement in sales to commercial and industrial customers, and the ramp-up of new data center customers. Though the total expected impact of COVID-19 on future sales remains unknown, APS experienced higher electric residential sales and lower electric commercial and industrial sales from the outset of the pandemic through April 2021.

Beginning in May 2021, electric sales to commercial and industrial customers increased to levels in line with pre-COVID sales and such sales levels have remained to date.

For the three years through 2021, annual retail electricity sales growth averaged 1.7%, adjusted to exclude the effects of weather variations. We currently project that annual retail electricity sales in kWh will increase in the range of 1.5% to 2.5% for 2022, and average annual growth will be in the range of 3.5% to 4.5% through 2024, including the effects of customer conservation, energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. This projected sales growth range includes the impacts of new, large manufacturing facilities, which are expected to contribute to average annual growth in the range of 1.0% to 2.0% through 2024. This projected sales growth range also includes our estimated contributions of several large data centers, but not all, and we will continue to estimate contributions and evaluate sales guidance as these customers develop more usage history. These estimates could be further impacted by changes in the expected growth of the Arizona economy, slower than expected ramp-up of the new data centers, larger manufacturing facilities not coming to Arizona as expected, a change in the duration of remote work, changes in the expected commercial and industrial expansions, or acceleration of the expected effects of customer conservation, energy efficiency and distributed renewable generation initiatives.

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, ramp-up of data centers, impacts of energy efficiency programs and growth in DG, and responses to retail price changes. Based on past experience, a 1% variation in our annual residential and small commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $20 million, and a 1% variation in our annual large commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $5 million.

Weather. In forecasting the retail sales growth numbers provided above, we assume normal weather patterns based on historical data. 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 Condensed 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.

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 10.7% of the assessed value for 2021, 10.8% for 2020 and 10.9% for 2019. 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.

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.

Interest Expense. Interest expense is affected by the amount of debt outstanding and the interest rates on that debt (see Note 3). 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.

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.

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 — Three-month period ended March 31, 2022, compared with three-month period ended March 31, 2021.

Our consolidated net income attributable to common shareholders for the three months ended March 31, 2022, was $17 million, compared with consolidated net income attributable to common shareholders of $36 million for the prior-year period. The results reflect a decrease of approximately $18 million for the regulated electricity segment primarily due to higher depreciation and amortization expense resulting from the absence of the Ocotillo modernization project and the Four Corners SCR project regulatory deferrals that ended upon the 2019 Rate Case effective date and increased plant assets and higher income taxes. These negative factors were partially offset by higher revenue driven by customer usage and customer growth, increased transmission revenue and lower operations and maintenance expense.

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

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 516	$ 497	$ 19
Operations and maintenance	(217)	(229)	12
Depreciation and amortization	(187)	(158)	(29)
Taxes other than income taxes	(58)	(59)	1
Pension and other postretirement non-service credits - net	24	28	(4)
All other income and expenses, net	9	15	(6)
Interest charges, net of allowance for borrowed funds used during construction	(61)	(57)	(4)
Income taxes	(4)	4	(8)
Less income related to noncontrolling interests (Note 6)	(4)	(5)	1
Regulated electricity segment income	18	36	(18)
All other	(1)	—	(1)
Net Income Attributable to Common Shareholders	$ 17	$ 36	$ (19)

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $19 million higher for the three months ended March 31, 2022, compared with the prior-year period. The following table summarizes the major components of this change:

	Increase (Decrease)		
	Operating revenues	**Fuel and purchased power expenses**	**Net change**
		(dollars in millions)	
Lower refunds in the current year related to the Tax Act (Note 4)	$ 31	$ —	$ 31
Higher retail revenue due to customer growth and changes in customer usage patterns, partially offset by the impacts of energy efficiency and distributed generation	22	9	13
Higher transmission revenues (Note 4)	12	—	12
Higher renewable energy regulatory surcharges, partially offset by operations and maintenance costs	5	—	5
Effects of weather	(3)	(1)	(2)
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	52	57	(5)
Lost fixed cost recovery	(10)	—	(10)
Impact of new retail base rates from 2019 ACC general rate case effective December 1, 2021	(23)	—	(23)
Miscellaneous items, net	—	2	(2)
Total	$ 86	$ 67	$ 19

Operations and maintenance. Operations and maintenance expenses decreased $12 million for the three months ended March 31, 2022, compared with the prior-year period primarily because of:

- A decrease of $15 million in non-nuclear generation costs primarily due to lower planned outages and lower operating costs;
- A decrease of $6 million related to employee benefits;
- An increase of $5 million primarily related to costs for renewable energy and similar regulatory programs, which are partially offset in operating revenues and purchased power; and
- An increase of $4 million in other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $29 million higher for the three months ended March 31, 2022, compared to the prior-year period primarily due to $16 million for the Ocotillo modernization project and the Four Corners SCR project regulatory deferrals that ended upon the 2019 Rate Case effective date and $13 million related to increased plant in service and updated depreciation rates.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $4 million lower for the three months ended March 31, 2022, compared to the prior-year period primarily due to actual market returns being lower than estimated returns in 2021.

Income taxes. Income taxes were $8 million higher for the three months ended March 31, 2022, compared with the prior-year period primarily due to lower amortization of excess deferred taxes and the net operating loss carryback benefit that the Company recognized during the first quarter of 2021, partially offset by lower pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

Our primary sources of cash are dividends from APS and external debt and equity issuances. An ACC order 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 March 31, 2022, APS's common equity ratio, as defined, was 51%. Its total shareholder equity was approximately $6.8 billion, and total capitalization was approximately $13.3 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $5.3 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 financing 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 (dollars in millions):

Pinnacle West Consolidated

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021	Net Change
Net cash flow provided by operating activities	$ 340	$ 202	$ 138
Net cash flow used for investing activities	(374)	(348)	(26)
Net cash flow provided by financing activities	38	103	(65)
Net change in cash and cash equivalents	$ 4	$ (43)	$ 47

Arizona Public Service Company

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021	Net Change
Net cash flow provided by operating activities	$ 341	$ 203	$ 138
Net cash flow used for investing activities	(363)	(352)	(11)
Net cash flow provided by financing activities	25	106	(81)
Net change in cash and cash equivalents	$ 3	$ (43)	$ 46

Operating Cash Flows

Three-month period ended March 31, 2022, compared with three-month period ended March 31, 2021. Pinnacle West's consolidated net cash provided by operating activities was $340 million in 2022, compared to $202 million in 2021, an increase of $138 million in net cash provided by operating activities primarily due to $97 million higher cash receipts from electric revenues, $45 million other changes in working capital and $13 million lower interest payments, partially offset by $31 million higher payments for operations and maintenance costs.

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 138% funded as of January 1, 2022, and 131% as of January 1, 2021. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We have not made voluntary contributions to our pension plan year-to-date in 2022. The minimum required contributions for the pension plan are zero and we do not expect to make any contributions in 2022, 2023 or 2024. With regard to contributions to our other postretirement benefit plan, we have not made a contribution year-to-date in 2022 and do not expect to make any contributions in 2022, 2023 or 2024. We continually monitor financial market volatility and its impact on our retirement plans and other postretirement benefits, but we believe, our liability driven investment strategy helps to minimize the impact of market volatility on our plan's funded status. For instance, our pension plan's funded status, as measured for accounting principles generally accepted in the United States of America ("GAAP") purposes, is still above

107% funded as of December 31, 2021, and our postretirement benefit plans have a funded status, also as measured for GAAP purposes at December 31, 2021, in excess of 145%. See Note 5 for additional details.

The Coronavirus Aid, Relief, and Economic Security (CARES) Act allowed employers to defer payments of the employer share of Social Security payroll taxes that would have otherwise been owed from March 27, 2020, through December 31, 2020. We deferred the cash payment of the employer's portion of Social Security payroll taxes for the period July 1, 2020, through December 31, 2020, that was approximately $18 million. We paid approximately $9 million on December 28, 2021, and will pay the second half of this cash deferral by December 31, 2022.

Investing Cash Flows

Three-month period ended March 31, 2022, compared with three-month period ended March 31, 2021. Pinnacle West's consolidated net cash used for investing activities was $374 million in 2022, compared to $348 million in 2021, an increase of $26 million primarily related to increased capital expenditures and BCE investment activity.

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

Capital Expenditures
(dollars in millions)

	2022	2023	2024
APS			
Generation:			
Clean:			
Nuclear Generation	$ 110	$ 120	$ 110
Renewables and Energy Storage Systems ("ESS") (a)	230	210	450
Other Generation (b)	250	270	190
Distribution	510	530	500
Transmission	250	210	210
Other (c)	175	185	190
Total APS	$ 1,525	$ 1,525	$ 1,650

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

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

Generation capital expenditures are comprised of various additions and improvements to APS's clean resources, including nuclear plants, renewables and ESS. Generation capital expenditures also include improvements to existing fossil plants. Examples of the types of projects included in the forecast of generation capital expenditures are additions of renewables and energy storage, and upgrades and capital replacements of various nuclear and fossil power plant equipment, such as turbines, boilers, and environmental equipment. We are monitoring the status of environmental matters, which, depending on their final outcome, could require modification to our planned environmental expenditures.

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

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

Financing Cash Flows and Liquidity

Three-month period ended March 31, 2022, compared with three-month period ended March 31, 2021. Pinnacle West's consolidated net cash provided by financing activities was $38 million in 2022, compared to $103 million in 2021, a decrease of $65 million in net cash provided by financing activities primarily due to higher long-term debt repayments of $150 million and a net decrease in short-term borrowing of $75 million, partially offset by $162 million in higher issuances of long-term debt.

APS's consolidated net cash provided by financing activities was $25 million in 2022, compared to $106 million in 2021, a decrease of $81 million in net cash provided by financing activities primarily due to a net decrease in short-term borrowing of $228 million, partially offset by an equity infusion of $150 million in 2022.

Significant Financing Activities. On April 20, 2022, the Pinnacle West Board of Directors declared a dividend of $0.85 per share of common stock, payable on June 1, 2022, to shareholders of record on May 2, 2022.

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 programs, to finance indebtedness, and other general corporate purposes. See Note 3 for more information on available credit facilities.

Other Financing Matters. See Note 7 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 March 31, 2022, the ratio was approximately 56% for Pinnacle West and 49% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could "cross-default" other debt. See further discussion of "cross-default" provisions below.

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

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

On December 17, 2020, the ACC issued a financing order that, subject to specified parameters and procedures, increased APS's long-term debt limit from $5.9 billion to $7.5 billion, and authorized APS's short-term debt authorization equal to the sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power). On April 6, 2022, APS filed an application with the ACC to increase the long-term debt limit under the terms required by APS from $7.5 billion to $8.0 billion and to continue its authorization of short-term debt granted in the 2020 financing order. See Note 3 for further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of April 28, 2022, are shown below. We are disclosing these credit ratings to enhance understanding of our cost of short-term and long-term capital and our ability to access the markets for liquidity and long-term debt. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS's securities and/or result in an increase in the cost of, or limit access to, capital. Such revisions may also result in substantial additional cash or other collateral requirements related to certain derivative instruments, insurance policies, natural gas transportation, fuel supply, and other energy-related contracts. At this time, we believe we have sufficient available liquidity resources to respond to a potential downward revision to our credit ratings.

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

Contractual Obligations

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

- Pinnacle West and APS have material long-term debt obligations that mature at various dates through 2050 and bear interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using average rates at March 31, 2022. See Note 3.
- Pinnacle West and APS maintain committed revolving credit facilities. See Note 3 for short-term debt details.
- Fuel and purchased power commitments include purchases of coal, electricity, natural gas, renewable energy, nuclear fuel, and natural gas transportation. See Notes 4 and 8. Purchase obligations includes capital expenditures and other obligations. Commitments related to purchased power lease contracts are also considered fuel and purchased power commitments. See Note 8.
- APS holds certain contracts to purchase renewable energy credits in compliance with the RES. See Notes 4 and 8.
- APS is required to make payments to the noncontrolling interests related to the Palo Verde sale leaseback through 2033. See Note 6.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In preparing the financial statements in accordance with GAAP, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. There have been no changes to our critical accounting policies and estimates since our 2021 Form 10-K. See “Critical Accounting Policies” in Item 7 of the 2021 Form 10-K for further details about our critical accounting policies and estimates.

MARKET AND CREDIT RISKS

Market Risks

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

Interest Rate and Equity Risk

We have exposure to changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and the market value of fixed income securities held by our nuclear decommissioning trusts, other special use funds (see Note 11 and Note 12), and benefit plan assets. The nuclear decommissioning trusts, 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.

Commodity Price Risk

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

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

	Three Months Ended March 31,	
	2022	2021
Mark-to-market of net positions at beginning of period	$ 107	$ (13)
Increase in regulatory liability	190	30
Mark-to-market of net positions at end of period	$ 297	$ 17

We had no activities or amounts recognized in OCI during the three months ended March 31, 2022 and 2021.

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at March 31, 2022, by maturities and by the type of valuation that is performed to calculate the fair values, classified in their entirety based on the lowest level of input that is significant to the fair value measurement. See Note 1, “Derivative Accounting” and “Fair Value Measurements” in Item 8 of our 2021 Form 10-K and Note 11 for more discussion of our valuation methods.

Source of Fair Value	2022	2023	2024	2025	2026	Total Fair Value
Observable prices provided by other external sources	$ 171	$ 91	$ 26	$ —	$ —	$ 288
Prices based on unobservable inputs	6	3	—	—	—	9
Total by maturity	$ 177	$ 94	$ 26	$ —	$ —	$ 297

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 Condensed Consolidated Balance Sheets (dollars in millions):

	March 31, 2022 Gain (Loss)		December 31, 2021 Gain (Loss)	
	Price Up 10%	**Price Down 10%**	**Price Up 10%**	**Price Down 10%**
Mark-to-market changes reported in:				
Regulatory asset (liability) (a)				
Electricity	$ 8	$ (8)	$ —	$ —
Natural gas	65	(65)	50	(50)
Total	$ 73	$ (73)	$ 50	$ (50)

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

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Key Financial Drivers" and "Market and Credit Risks" in Item 2 above for a discussion of quantitative and qualitative disclosures about market risks.

Item 4. 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, as amended (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 March 31, 2022. Based on that evaluation, Pinnacle West's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, Pinnacle West's disclosure controls and procedures were effective.

APS's management, with the participation of APS's Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of APS's disclosure controls and procedures as of March 31, 2022. Based on that evaluation, APS's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, APS's disclosure controls and procedures were effective.

(b) Changes in Internal Control Over Financial Reporting

The term "internal control over financial reporting" (defined in SEC Rule 13a-15(f)) refers to the process of a company that is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

No change in Pinnacle West's or APS's internal control over financial reporting occurred during the fiscal quarter ended March 31, 2022, that materially affected, or is reasonably likely to materially affect, Pinnacle West's or APS's internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

See "Business of Arizona Public Service Company — Environmental Matters" in Item 1 of the 2021 Form 10-K with regard to pending or threatened litigation and other matters.

See Note 4 for ACC and FERC-related matters.

See Note 8 for information regarding environmental matters, Superfund-related matters and other disputes.

Item 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A — Risk Factors in the 2021 Form 10-K, which could materially affect the business, financial condition, cash flows or future results of Pinnacle West and APS. The risks described in the 2021 Form 10-K are not the only risks facing Pinnacle West and APS. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect the business, financial condition, cash flows and/or operating results of Pinnacle West and APS.

The risk factor below is an update to our 2021 Form 10-K.

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

General economic factors that are beyond the Company's control impact the Company's forecasts and actual performance. These factors include interest rates; recession; inflation; deflation; unemployment trends; sanctions, trade restrictions, military interventions and the threat or possibility of war; terrorism or other global or national unrest; and political or financial instability. In particular, while inflation has been relatively flat in recent years, during 2021 and 2022, the United States' economy has experienced a substantial rise in the inflation rate. There is increased uncertainty in the near-term outlook as to whether the rise in inflation will continue. Increases in inflation raise the Company's costs for commodities, labor, materials and services. A failure to recover through our rates increased costs caused by increased inflation could have a material adverse impact on our financial condition, results of operations or cash flows.

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

(a) Exhibits

Exhibit No.	Registrant(s)	Description
31.1	Pinnacle West	Certificate of Jeffrey B. Guldner, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
31.2	Pinnacle West	Certificate of 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*	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*	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
101.INS	Pinnacle West APS	XBRL Instance Document - the instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.
101.SCH	Pinnacle West APS	XBRL Taxonomy Extension Schema Document
101.CAL	Pinnacle West APS	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	Pinnacle West APS	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	Pinnacle West APS	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	Pinnacle West APS	XBRL Taxonomy Definition Linkbase Document
104	Pinnacle West APS	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

*Furnished herewith as an Exhibit.

In addition, Pinnacle West and APS hereby incorporate the following Exhibits pursuant to Exchange Act Rule 12b-32 and Regulation §229.10(d) by reference to the filings set forth below:

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit(1)	Date Filed
3.1	Pinnacle West	Pinnacle West Capital Corporation Bylaws, amended as of February 19, 2020	3.1 to Pinnacle West/APS February 25, 2020 Form 8-K Report, File Nos. 1-8962 and 1-4473	2/25/2020
3.2	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 Nos. 1-8962 and 1-4473	8/7/2008
3.3	APS	Articles of Incorporation, restated as of May 25, 1988	4.2 to APS's Form S-3 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report, File No. 1-4473	9/29/1993
3.4	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
3.5	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 Nos. 1-8962 and 1-4473	2/20/2009

(1) Reports filed under File Nos. 1-4473 and 1-8962 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Dated: May 4, 2022

By: /s/ Theodore N. Geisler
Theodore N. Geisler
Senior Vice President and
Chief Financial Officer
(Principal Financial Officer and
Officer Duly Authorized to sign this Report)

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Dated: May 4, 2022

By: /s/ Theodore N. Geisler
Theodore N. Geisler
Senior Vice President and
Chief Financial Officer
(Principal Financial Officer and
Officer Duly Authorized to sign this Report)

Exhibit 31.1

CERTIFICATION

I, Jeffrey B. Guldner, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q 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: May 4, 2022

/s/ Jeffrey B. Guldner

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

Exhibit 31.2

CERTIFICATION

I, Theodore N. Geisler, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q 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: May 4, 2022

/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 Quarterly Report on Form 10-Q 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: May 4, 2022

/s/ Jeffrey B. Guldner

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

Exhibit 31.4

CERTIFICATION

I, Theodore N. Geisler, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q 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: May 4, 2022

/s/ Theodore N. Geisler

Theodore N. Geisler
Senior Vice President and Chief Financial Officer

Exhibit 32.1

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 Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation for the quarter ended March 31, 2022 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West Capital Corporation.

Date: May 4, 2022

/s/ Jeffrey B. Guldner
Jeffrey B. Guldner
Chairman of the Board, 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 Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation for the quarter ended March 31, 2022 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West Capital Corporation.

Date: May 4, 2022

/s/ Theodore N. Geisler
Theodore N. Geisler
Senior Vice President and Chief Financial Officer

Exhibit 32.2

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 Quarterly Report on Form 10-Q of Arizona Public Service Company for the quarter ended March 31, 2022 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Arizona Public Service Company.

Date: May 4, 2022

/s/ Jeffrey B. Guldner
Jeffrey B. Guldner
Chairman of the Board, 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 Quarterly Report on Form 10-Q of Arizona Public Service Company for the quarter ended March 31, 2022 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Arizona Public Service Company.

Date: May 4, 2022

/s/ Theodore N. Geisler
Theodore N. Geisler
Senior Vice President and Chief Financial Officer