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 June 30, 2021

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 July 29, 2021:	112,785,588
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of July 29, 2021:	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, 2020 ("2020 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, supply chain, expenses, 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, the general economy or social conditions, customer and sales growth (or decline), the effects of energy conservation measures and distributed generation, and technological advancements;
- power plant and transmission system performance and outages;
- competition in retail and wholesale power markets;
- regulatory and judicial decisions, developments and proceedings;
- new legislation, ballot initiatives and regulation, including those relating to environmental requirements, regulatory 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, terrorist attack, physical attack, severe storms, droughts, or other catastrophic events, such as fires, explosions, pandemic health events, or similar occurrences;
- the development of new technologies which may affect electric sales or delivery;
- the cost of debt and equity capital and the ability to access capital markets when required;
- environmental, economic and other concerns surrounding coal-fired generation, including regulation of greenhouse gas emissions;
- volatile fuel and purchased power costs;
- the investment performance of the assets of our nuclear decommissioning trust, pension, and other postretirement benefit plans and the resulting impact on future funding requirements;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;
- potential shortfalls in insurance coverage;
- new accounting requirements or new interpretations of existing requirements;
- generation, transmission and distribution facility and system conditions and operating costs;
- the ability to meet the anticipated future need for additional generation and associated transmission facilities in our region;
- the willingness or ability of our counterparties, power plant participants and power plant 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 2020 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 June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
OPERATING REVENUES (NOTE 2)	$ 1,000,249	$ 929,590	$ 1,696,724	$ 1,591,520
OPERATING EXPENSES				
Fuel and purchased power	269,835	238,382	468,062	426,903
Operations and maintenance	229,690	219,392	459,745	440,710
Depreciation and amortization	158,750	152,482	316,570	306,561
Taxes other than income taxes	59,495	56,768	118,978	113,536
Other expenses	4,093	692	7,449	1,514
Total	721,863	667,716	1,370,804	1,289,224
OPERATING INCOME	278,386	261,874	325,920	302,296
OTHER INCOME (DEDUCTIONS)				
Allowance for equity funds used during construction	9,990	8,811	19,197	16,508
Pension and other postretirement non-service credits — net	28,175	14,142	55,966	28,053
Other income (Note 9)	12,207	16,670	24,636	29,239
Other expense (Note 9)	(5,184)	(4,036)	(9,037)	(8,820)
Total	45,188	35,587	90,762	64,980
INTEREST EXPENSE				
Interest charges	62,777	62,690	124,715	121,924
Allowance for borrowed funds used during construction	(5,199)	(4,749)	(10,193)	(8,825)
Total	57,578	57,941	114,522	113,099
INCOME BEFORE INCOME TAXES	265,996	239,520	302,160	254,177
INCOME TAXES	46,560	41,061	42,210	20,852
NET INCOME	219,436	198,459	259,950	233,325
Less: Net income attributable to noncontrolling interests (Note 6)	3,739	4,874	8,612	9,747
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 215,697	$ 193,585	$ 251,338	$ 223,578
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	112,882	112,638	112,855	112,616
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	113,223	112,879	113,158	112,871
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING				
Net income attributable to common shareholders — basic	$ 1.91	$ 1.72	$ 2.23	$ 1.99
Net income attributable to common shareholders — diluted	$ 1.91	$ 1.71	$ 2.22	$ 1.98

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 June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
NET INCOME	$ 219,436	$ 198,459	$ 259,950	$ 233,325
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Derivative instruments:				
Net unrealized gain (loss), net of tax benefit (expense) of $(286), $513, $(372) and $805	870	(1,549)	1,132	(1,257)
Reclassification of net realized gain, net of tax expense of $0, $87, $0 and $481	—	262	—	282
Pension and other postretirement benefit activity, net of tax benefit (expense) $(21), $334, $(357) and $90	64	(1,009)	1,086	196
Total other comprehensive income	934	(2,296)	2,218	(779)
COMPREHENSIVE INCOME	220,370	196,163	262,168	232,546
Less: Comprehensive income attributable to noncontrolling interests	3,739	4,874	8,612	9,747
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 216,631	$ 191,289	$ 253,556	$ 222,799

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

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

	June 30, 2021	December 31, 2020
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 14,146	$ 59,968
Customer and other receivables	357,130	313,576
Accrued unbilled revenues	223,918	132,197
Allowance for doubtful accounts (Note 2)	(22,769)	(19,782)
Materials and supplies (at average cost)	340,672	314,745
Fossil fuel (at average cost)	25,074	19,552
Income tax receivable	—	6,792
Assets from risk management activities (Note 7)	82,309	2,931
Deferred fuel and purchased power regulatory asset (Note 4)	300,912	175,835
Other regulatory assets (Note 4)	119,890	115,878
Other current assets	81,901	76,627
Total current assets	1,523,183	1,198,319
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 11 and 12)	1,223,088	1,138,435
Other special use funds (Notes 11 and 12)	358,436	254,509
Other assets	112,091	92,922
Total investments and other assets	1,693,615	1,485,866
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	21,236,805	20,837,885
Accumulated depreciation and amortization	(7,278,877)	(7,110,310)
Net	13,957,928	13,727,575
Construction work in progress	1,062,911	937,384
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	96,101	98,036
Intangible assets, net of accumulated amortization	279,911	282,570
Nuclear fuel, net of accumulated amortization	109,110	113,645
Total property, plant and equipment	15,505,961	15,159,210
DEFERRED DEBITS		
Regulatory assets (Note 4)	1,173,977	1,133,987
Operating lease right-of-use assets (Note 15)	718,948	505,064
Assets for pension and other postretirement benefits (Note 5)	407,821	502,992
Other	38,073	34,983
Total deferred debits	2,338,819	2,177,026
TOTAL ASSETS	$ 21,061,578	$ 20,020,421

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

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

	June 30, 2021	December 31, 2020
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 377,157	$ 318,585
Accrued taxes	183,037	159,551
Accrued interest	56,864	56,962
Common dividends payable	93,610	93,531
Short-term borrowings (Note 3)	504,700	169,000
Current maturities of long-term debt (Note 3)	150,000	—
Customer deposits	44,419	48,340
Liabilities from risk management activities (Note 7)	1,512	7,557
Liabilities for asset retirements (Note 16)	15,646	15,586
Operating lease liabilities (Note 15)	128,673	74,785
Regulatory liabilities (Note 4)	327,612	229,088
Other current liabilities	140,038	187,448
Total current liabilities	2,023,268	1,360,433
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 3)	6,315,927	6,314,266
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,192,169	2,135,403
Regulatory liabilities (Note 4)	2,443,312	2,450,169
Liabilities for asset retirements (Note 16)	716,344	689,497
Liabilities for pension benefits (Note 5)	163,207	166,484
Liabilities from risk management activities (Note 7)	—	11,062
Customer advances	247,531	221,032
Coal mine reclamation	172,357	170,097
Deferred investment tax credit	187,720	191,372
Unrecognized tax benefits	6,002	5,834
Operating lease liabilities (Note 15)	547,164	361,336
Other	211,678	190,643
Total deferred credits and other	6,887,484	6,592,929
COMMITMENTS AND CONTINGENCIES (NOTE 8)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 112,819,703 and 112,760,051 issued at respective dates	2,692,015	2,677,482
Treasury stock at cost; 36,153 and 72,006 shares at respective dates	(3,079)	(6,289)
Total common stock	2,688,936	2,671,193
Retained earnings	3,089,266	3,025,106
Accumulated other comprehensive loss	(60,578)	(62,796)
Total shareholders' equity	5,717,624	5,633,503
Noncontrolling interests (Note 6)	117,275	119,290
Total equity	5,834,899	5,752,793
TOTAL LIABILITIES AND EQUITY	$ 21,061,578	$ 20,020,421

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)

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 259,950	$ 233,325
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	350,536	343,173
Deferred fuel and purchased power	(135,905)	(26,473)
Deferred fuel and purchased power amortization	10,828	(4,815)
Allowance for equity funds used during construction	(19,197)	(16,508)
Deferred income taxes	30,231	22,229
Deferred investment tax credit	(3,651)	(3,386)
Stock compensation	13,484	9,130
Changes in current assets and liabilities:		
Customer and other receivables	(41,138)	7,767
Accrued unbilled revenues	(91,721)	(63,413)
Materials, supplies and fossil fuel	(31,449)	10,295
Income tax receivable	6,792	4,605
Other current assets	(14,021)	(24,896)
Accounts payable	66,558	17,772
Accrued taxes	23,486	6,588
Other current liabilities	(39,638)	(45,334)
Change in other long-term assets	(118,036)	(4,885)
Change in other long-term liabilities	45,241	(96,142)
Net cash flow provided by operating activities	312,350	369,032
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(681,148)	(676,973)
Contributions in aid of construction	32,104	31,295
Allowance for borrowed funds used during construction	(10,193)	(8,825)
Proceeds from nuclear decommissioning trusts sales and other special use funds	587,842	391,859
Investment in nuclear decommissioning trusts and other special use funds	(588,982)	(393,000)
Other	10,809	3,123
Net cash flow used for investing activities	(649,568)	(652,521)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	150,000	1,088,886
Short-term borrowing and (repayments) — net	354,700	184,225
Short-term debt borrowings under revolving credit facility	—	751,690
Short-term debt repayments under revolving credit facility	(19,000)	(758,690)
Dividends paid on common stock	(183,500)	(172,566)
Repayment of long-term debt	—	(800,000)
Common stock equity issuance — net of purchases	(176)	(2,204)
Distributions to noncontrolling interests	(10,628)	(11,372)
Net cash flow provided by financing activities	291,396	279,969
NET DECREASE IN CASH AND CASH EQUIVALENTS	(45,822)	(3,520)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	59,968	10,283
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 14,146	$ 6,763

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 June 30, 2021							
	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, April 1, 2021	112,791,565	$2,687,052	(44,338)	$ (3,776)	$ 3,060,752	$ (61,512)	$ 124,164	$ 5,806,680
Net income		—		—	215,697	—	3,739	219,436
Other comprehensive income		—		—	—	934	—	934
Dividends on common stock ($1.66 per share)		—		—	(187,181)	—	—	(187,181)
Issuance of common stock	28,138	4,963		—	—	—	—	4,963
Reissuance of treasury stock for stock-based compensation and other		—	8,185	697	—	—	—	697
Other		—		—	(2)	—	—	(2)
Capital activities by noncontrolling interests		—		—	—	—	(10,628)	(10,628)
Balance, June 30, 2021	112,819,703	$2,692,015	(36,153)	$ (3,079)	$ 3,089,266	$ (60,578)	$ 117,275	$ 5,834,899

	Three Months Ended June 30, 2020							
	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, April 1, 2020	112,563,610	$2,664,387	(72,302)	$ (7,000)	$ 2,867,610	$ (55,579)	$ 127,414	$ 5,596,832
Net income		—		—	193,585	—	4,874	198,459
Other comprehensive loss		—		—	—	(2,296)	—	(2,296)
Dividends on common stock ($1.57 per share)		—		—	(176,086)	—	—	(176,086)
Issuance of common stock	27,514	1,131		—	—	—	—	1,131
Purchase of treasury stock (a)		—	(12,346)	(924)	—	—	—	(924)
Reissuance of treasury stock for stock-based compensation and other		—	48,665	4,734	—	—	—	4,734
Other		—		—	—	—	(1)	(1)
Capital activities by noncontrolling interests		—		—	—	—	(11,372)	(11,372)
Balance, June 30, 2020	112,591,124	$2,665,518	(35,983)	$ (3,190)	$ 2,885,109	$ (57,875)	$ 120,915	$ 5,610,477

(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.

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

Six Months Ended June 30, 2021

	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, Jan 1, 2021	112,760,051	$2,677,482	(72,006)	$ (6,289)	$ 3,025,106	$ (62,796)	$ 119,290	$ 5,752,793
Net income		—		—	251,338	—	8,612	259,950
Other comprehensive income		—		—	—	2,218	—	2,218
Dividends on common stock ($1.66 per share)		—		—	(187,176)	—	—	(187,176)
Issuance of common stock	59,652	14,533			—	—	—	14,533
Purchase of treasury stock (a)		—	(17,437)	(1,333)	—	—	—	(1,333)
Reissuance of treasury stock for stock-based compensation and other		—	53,290	4,543	—	—	—	4,543
Other					(2)	—	1	(1)
Capital activities by noncontrolling interests		—		—	—	—	(10,628)	(10,628)
Balance, June 30, 2021	112,819,703	$2,692,015	(36,153)	$ (3,079)	$ 3,089,266	$ (60,578)	$ 117,275	$ 5,834,899

Six Months Ended June 30, 2020

	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, Jan 1, 2020	112,540,126	$2,659,561	(103,546)	$ (9,427)	$ 2,837,610	$ (57,096)	$ 122,540	$ 5,553,188
Net income		—		—	223,578	—	9,747	233,325
Other comprehensive loss		—		—	—	(779)	—	(779)
Dividends on common stock ($1.57 per share)		—		—	(176,079)	—	—	(176,079)
Issuance of common stock	50,998	5,957		—	—	—	—	5,957
Purchase of treasury stock (a)		—	(33,070)	(3,010)	—	—	—	(3,010)
Reissuance of treasury stock for stock-based compensation and other		—	100,633	9,247	—	—	—	9,247
Capital activities by noncontrolling interests		—		—	—	—	(11,372)	(11,372)
Balance, June 30, 2020	112,591,124	$2,665,518	(35,983)	$ (3,190)	$ 2,885,109	$ (57,875)	$ 120,915	$ 5,610,477

(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 June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
OPERATING REVENUES (NOTE 2)	$1,000,249	$ 929,590	$1,696,724	$1,591,520
OPERATING EXPENSES				
Fuel and purchased power	269,835	238,382	468,062	426,903
Operations and maintenance	226,698	216,221	453,099	434,486
Depreciation and amortization	158,728	152,460	316,528	306,518
Taxes other than income taxes	59,478	56,758	118,950	113,516
Other expenses	4,093	692	7,449	1,514
Total	718,832	664,513	1,364,088	1,282,937
OPERATING INCOME	281,417	265,077	332,636	308,583
OTHER INCOME (DEDUCTIONS)				
Allowance for equity funds used during construction	9,990	8,811	19,197	16,508
Pension and other postretirement non-service credits — net	28,234	14,421	56,071	28,683
Other income (Note 9)	11,563	13,272	23,523	24,905
Other expense (Note 9)	(4,261)	(3,859)	(7,611)	(8,527)
Total	45,526	32,645	91,180	61,569
INTEREST EXPENSE				
Interest charges	59,930	56,802	119,318	112,538
Allowance for borrowed funds used during construction	(5,199)	(4,749)	(10,193)	(8,825)
Total	54,731	52,053	109,125	103,713
INCOME BEFORE INCOME TAXES	272,212	245,669	314,691	266,439
INCOME TAXES	48,725	43,677	51,044	24,229
NET INCOME	223,487	201,992	263,647	242,210
Less: Net income attributable to noncontrolling interests (Note 6)	3,739	4,874	8,612	9,747
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 219,748	$ 197,118	$ 255,035	$ 232,463

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 June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
NET INCOME	$ 223,487	$ 201,992	$ 263,647	$ 242,210
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Derivative instruments:				
Net unrealized gain, net of tax benefit of $0, $0, $0 and $292	—	—	—	292
Reclassification of net realized gain, net of tax expense $0, $87, $0 and $481	—	262	—	282
Pension and other postretirement benefits activity, net of tax benefit (expense) $(53), $361, $(357) and $124	159	(1,090)	1,086	(77)
Total other comprehensive income	159	(828)	1,086	497
COMPREHENSIVE INCOME	223,646	201,164	264,733	242,707
Less: Comprehensive income attributable to noncontrolling interests	3,739	4,874	8,612	9,747
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 219,907	$ 196,290	$ 256,121	$ 232,960

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

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

	June 30, 2021	December 31, 2020
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	$ 21,233,344	$ 20,834,424
Accumulated depreciation and amortization	(7,275,617)	(7,107,058)
Net	13,957,727	13,727,366
Construction work in progress	1,062,911	937,384
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	96,101	98,036
Intangible assets, net of accumulated amortization	279,755	282,415
Nuclear fuel, net of accumulated amortization	109,110	113,645
Total property, plant and equipment	15,505,604	15,158,846
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 11 and 12)	1,223,088	1,138,435
Other special use funds (Notes 11 and 12)	358,436	254,509
Other assets	68,248	46,010
Total investments and other assets	1,649,772	1,438,954
CURRENT ASSETS		
Cash and cash equivalents	11,954	57,310
Customer and other receivables	357,023	312,644
Accrued unbilled revenues	223,918	132,197
Allowance for doubtful accounts (Note 2)	(22,769)	(19,782)
Materials and supplies (at average cost)	340,672	314,745
Fossil fuel (at average cost)	25,074	19,552
Assets from risk management activities (Note 7)	82,309	2,931
Deferred fuel and purchased power regulatory asset (Note 4)	300,912	175,835
Other regulatory assets (Note 4)	119,890	115,878
Other current assets	51,482	47,593
Total current assets	1,490,465	1,158,903
DEFERRED DEBITS		
Regulatory assets (Note 4)	1,173,977	1,133,987
Operating lease right-of-use assets (Note 15)	717,411	503,475
Assets for pension and other postretirement benefits (Note 5)	400,414	495,673
Other	37,210	34,413
Total deferred debits	2,329,012	2,167,548
TOTAL ASSETS	$ 20,974,853	$ 19,924,251

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

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

	June 30, 2021	December 31, 2020
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	2,871,696	2,871,696
Retained earnings	3,284,989	3,216,955
Accumulated other comprehensive loss	(39,832)	(40,918)
Total shareholder equity	6,295,015	6,225,895
Noncontrolling interests (Note 6)	117,275	119,290
Total equity	6,412,290	6,345,185
Long-term debt less current maturities (Note 3)	5,819,198	5,817,945
Total capitalization	12,231,488	12,163,130
CURRENT LIABILITIES		
Short-term borrowings (Note 3)	495,000	—
Accounts payable	369,905	311,699
Accrued taxes	193,409	148,970
Accrued interest	56,202	56,322
Common dividends payable	93,500	93,500
Customer deposits	44,419	48,340
Liabilities from risk management activities (Note 7)	1,512	7,557
Liabilities for asset retirements (Note 16)	15,646	15,586
Operating lease liabilities (Note 15)	128,578	74,695
Regulatory liabilities (Note 4)	327,612	229,088
Other current liabilities	142,926	190,420
Total current liabilities	1,868,709	1,176,177
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,192,580	2,143,673
Regulatory liabilities (Note 4)	2,443,312	2,450,169
Liabilities for asset retirements (Note 16)	716,344	689,497
Liabilities for pension benefits (Note 5)	146,728	148,943
Liabilities from risk management activities (Note 7)	—	11,062
Customer advances	247,531	221,032
Coal mine reclamation	172,357	170,097
Deferred investment tax credit	187,720	191,372
Unrecognized tax benefits	39,995	39,410
Operating lease liabilities (Note 15)	545,534	359,653
Other	182,555	160,036
Total deferred credits and other	6,874,656	6,584,944
COMMITMENTS AND CONTINGENCIES (NOTE 8)		
TOTAL LIABILITIES AND EQUITY	$ 20,974,853	$ 19,924,251

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)

	Six Months Ended June 30,	
	2021	**2020**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 263,647	$ 242,210
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	350,494	343,130
Deferred fuel and purchased power	(135,905)	(26,473)
Deferred fuel and purchased power amortization	10,828	(4,815)
Allowance for equity funds used during construction	(19,197)	(16,508)
Deferred income taxes	23,161	15,233
Deferred investment tax credit	(3,651)	(3,386)
Changes in current assets and liabilities:		
Customer and other receivables	(41,963)	824
Accrued unbilled revenues	(91,721)	(63,413)
Materials, supplies and fossil fuel	(31,449)	10,295
Income tax receivable	—	7,313
Other current assets	(12,636)	(19,752)
Accounts payable	66,192	17,915
Accrued taxes	44,439	14,551
Other current liabilities	(39,749)	(40,381)
Change in other long-term assets	(114,154)	(7,356)
Change in other long-term liabilities	46,327	(91,983)
Net cash flow provided by operating activities	314,663	377,404
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(681,148)	(676,973)
Contributions in aid of construction	32,104	31,295
Allowance for borrowed funds used during construction	(10,193)	(8,825)
Proceeds from nuclear decommissioning trusts sales and other special use funds	587,842	391,859
Investment in nuclear decommissioning trusts and other special use funds	(588,982)	(393,000)
Other	2,986	(169)
Net cash flow used for investing activities	(657,391)	(655,813)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	—	591,936
Short-term borrowings and (repayments) — net	495,000	219,900
Short-term debt borrowings under revolving credit facility	—	540,000
Short-term debt repayments under revolving credit facility	—	(540,000)
Repayment of long-term debt	—	(350,000)
Dividends paid on common stock	(187,000)	(176,000)
Distributions to noncontrolling interests	(10,628)	(11,372)
Net cash flow provided by financing activities	297,372	274,464
NET DECREASE IN CASH AND CASH EQUIVALENTS	(45,356)	(3,945)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	57,310	10,169
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 11,954	$ 6,224

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 June 30, 2021						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, April 1, 2021	71,264,947	$ 178,162	$ 2,871,696	$ 3,252,244	$ (39,991)	$ 124,164	$ 6,386,275
Net Income		—	—	219,748	—	3,739	223,487
Other comprehensive income		—	—	—	159	—	159
Dividends on common stock		—	—	(187,000)	—	—	(187,000)
Other		—	—	(3)	—	—	(3)
Capital activities by noncontrolling activities		—	—	—	—	(10,628)	(10,628)
Balance, June 30, 2021	71,264,947	$ 178,162	$ 2,871,696	$ 3,284,989	$ (39,832)	$ 117,275	$ 6,412,290

	Three Months Ended June 30, 2020						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, April 1, 2020	71,264,947	$ 178,162	$ 2,721,696	$ 3,047,269	$ (34,197)	$ 127,414	$ 6,040,344
Net Income		—	—	197,118	—	4,874	201,992
Other comprehensive loss		—	—	—	(828)	—	(828)
Dividends on common stock		—	—	(176,000)	—	—	(176,000)
Other		—	—	2	—	(1)	1
Capital activities by noncontrolling activities		—	—	—	—	(11,372)	(11,372)
Balance, June 30, 2020	71,264,947	$ 178,162	$ 2,721,696	$ 3,068,389	$ (35,025)	$ 120,915	$ 6,054,137

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)

	Six Months Ended June 30, 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		—	—	255,035	—	8,612	263,647
Other comprehensive income		—	—	—	1,086	—	1,086
Dividends on common stock		—	—	(187,000)			(187,000)
Other		—	—	(1)	—	1	—
Capital activities by noncontrolling activities		—	—		—	(10,628)	(10,628)
Balance, June 30, 2021	71,264,947	$ 178,162	$ 2,871,696	$ 3,284,989	$ (39,832)	$ 117,275	$ 6,412,290

	Six Months Ended June 30, 2020						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, January 1, 2020	71,264,947	$ 178,162	$ 2,721,696	$ 3,011,927	$ (35,522)	$ 122,540	$ 5,998,803
Net Income		—	—	232,463	—	9,747	242,210
Other comprehensive income		—	—	—	497	—	497
Dividends on common stock		—	—	(176,000)	—	—	(176,000)
Other		—	—	(1)	—	—	(1)
Capital activities by noncontrolling activities		—	—	—	—	(11,372)	(11,372)
Balance, June 30, 2020	71,264,947	$ 178,162	$ 2,721,696	$ 3,068,389	$ (35,025)	$ 120,915	$ 6,054,137

The accompanying notes are an integral part of the 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 2020 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. The order provides 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 has 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 has left all other aspects of the AFUDC formula composite rate calculation unchanged. This change impacts the AFUDC composite rate in both 2020 and 2021 but does not impact prior years. Furthermore, the change in the composite rate calculation does not impact our accounting treatment for these costs. The change will not have a material impact on our financial statements. See Note 1 in our 2020 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):

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Cash paid (received) during the period for:		
Income taxes, net of refunds	$ (788)	$ (3,028)
Interest, net of amounts capitalized	112,010	107,417
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 105,515	$ 87,815
Dividends accrued but not yet paid	93,610	88,066

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

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Cash paid (received) during the period for:		
Income taxes, net of refunds	$ 3,317	$ —
Interest, net of amounts capitalized	107,044	100,991
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 105,515	$ 87,815
Dividends accrued but not yet paid	93,500	88,000

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 June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Retail Electric Revenue				
Residential	$ 531,717	$ 515,128	$ 872,555	$ 840,201
Non-Residential	420,995	381,121	735,778	684,472
Wholesale Energy Sales	18,007	15,927	35,604	30,595
Transmission Services for Others	22,579	14,766	41,572	30,693
Other Sources	6,951	2,648	11,215	5,559
Total operating revenues	$ 1,000,249	$ 929,590	$ 1,696,724	$ 1,591,520

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 15 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 and six months ended June 30, 2021 were $980 million and $1,663 million, respectively and for the three and six months ended June 30, 2020 were $915 million and $1,563 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 and six months ended June 30, 2021 our revenues that do not qualify as revenue from contracts with customers were $20 million and $34 million, respectively, and for the three and six months ended June 30, 2020 were $15 million and $29 million, respectively. This relates primarily to certain regulatory cost recovery mechanisms that are considered alternative revenue programs. We recognize revenue associated with alternative revenue programs when specific events permitting recognition are completed. Certain amounts associated with alternative revenue programs will subsequently be billed to customers; however, we do not reclassify billed amounts into revenue from contracts with customers. See Note 4 for a discussion of our regulatory cost recovery mechanisms.

Contract Assets and Liabilities from Contracts with Customers

There were no material contract assets, contract liabilities, or deferred contract costs recorded on the Condensed Consolidated Balance Sheets as of June 30, 2021 or December 31, 2020.

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.

On March 13, 2020, due to the COVID-19 pandemic we voluntarily suspended disconnections of customers for nonpayment. The suspension of customer disconnections was extended from March 13, 2020 through December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021 and certain customers with past due balances were placed on eight-month payment arrangements. During this time our disconnection policies were also impacted by the Summer Disconnection Moratorium. These circumstances and the on-going COVID-19 pandemic have impacted our allowance for doubtful accounts, including our write-off factor. 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. See Note 4 for additional details.

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

	June 30, 2021	December 31, 2020
Allowance for doubtful accounts, balance at beginning of period	$ 19,782	$ 8,171
Bad debt expense	10,048	20,633
Actual write-offs	(7,061)	(9,022)
Allowance for doubtful accounts, balance at end of period	$ 22,769	$ 19,782

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 May 5, 2020, Pinnacle West refinanced its 364-day $50 million term loan agreement with a new 364-day $31 million term loan agreement that would have matured May 4, 2021. Borrowings under the agreement bore interest at Eurodollar Rate plus 1.40% per annum. Pinnacle West repaid this agreement on April 27, 2021.

On December 23, 2020, Pinnacle West entered into a $150 million term loan facility that matures June 30, 2022. The proceeds were received on January 4, 2021 and used for general corporate purposes.

On May 28, 2021, Pinnacle West replaced its $200 million revolving credit facility that would have matured on July 11, 2023, with a new $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 June 30, 2021, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding under the credit facility and $9.7 million of outstanding commercial paper borrowings.

APS

On May 28, 2021, APS replaced its two $500 million revolving credit facilities that would have matured in June 2022 and July 2023, with two new $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 June 30, 2021, APS had no outstanding borrowings under its revolving credit facilities, no letters of credit outstanding under the credit facilities and $495 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.

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

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 June 30, 2021		As of December 31, 2020	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 646,729	$ 654,095	$ 496,321	$ 509,050
APS	5,819,198	6,746,984	5,817,945	7,103,791
Total	$ 6,465,927	$ 7,401,079	$ 6,314,266	$ 7,612,841

4. Regulatory Matters

COVID-19 Pandemic

Due to the COVID-19 pandemic, APS voluntarily suspended disconnections of customers for nonpayment and waived late payment fees beginning March 13, 2020 until December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021 and customers were automatically placed on eight-month payment arrangements if they had past due balances at the end of the disconnection period of $75 or greater. APS will continue to waive late payment fees until October 15, 2021. APS has experienced and is continuing to experience an increase in bad debt expense associated with the COVID-19 pandemic, the Summer Disconnection Moratorium (defined below) and the related write-offs of customer delinquent accounts. In February 2021, due to COVID-19 APS delayed the annual reset of the PSA. Rather than the increase being effective February 2021, the PSA reset was implemented with 50% of the increase effective April 2021 and the remaining 50% increase effective November 2021 (see below for discussion of EIS, TEAM Phase II and PSA).

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 Demand Side Management ("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 approved amount of $36 million was the result of the kWh credit being based on historic consumption, which was different than actual consumption in the refund period. The difference was recorded to the DSM balancing account and was included in the 2021 DSM Implementation Plan, which was approved by the ACC on June 13, 2021 (see below for discussion of the DSM Adjustor Charge).

In 2020, APS spent more than $15 million to assist customers and local non-profits and community organizations to help with the impact of the COVID-19 pandemic, with $12.4 million of these dollars directly committed to bill assistance programs (the "COVID Customer Support Fund"). The COVID Customer Support Fund was comprised of a series of voluntary commitments of funds that are not recoverable through rates throughout 2020 of approximately $8.8 million. An additional $3.6 million in bill credits for limited income customers was ordered by the ACC in December 2020 of which 50%, up to a maximum of $2.5 million, was committed to be funds that are not recoverable through rates with the remaining being deferred for potential future recovery in rates. Included in the COVID Customer Support Fund were programs that assisted customers that had a delinquency of two or more months with a one-time credit of $100, an expanded credit of $300 for limited income customers, programs to assist extra small and small non-residential customers with a one-time credit of $1,000, and other targeted programs allocated to assist with other COVID-19 needs in support of utility bill assistance. The December 2020 ACC order further assisted delinquent limited income customers with an additional bill credit of up to $250 or their delinquent balance, whichever was less. APS has distributed all funds for all COVID Customer Support Fund programs combined. Beyond the COVID Customer Support Fund, APS has also provided $2.7 million to assist local non-profits and community organizations working to mitigate the impacts of the COVID-19 pandemic.

2019 Retail Rate Case Filing with the Arizona Corporation Commission

In accordance with the requirements of the 2019 rate review order described below, APS filed an application with the ACC on October 31, 2019 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 selective catalytic reduction ("SCR") project that is currently the subject of a separate proceeding (see "SCR Cost Recovery" below). It also reflects a net credit to base rates of approximately $115 million primarily due to the prospective inclusion of rate refunds currently provided through the 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 twelve months ended June 30, 2019, adjusted as described below;
- an original cost rate base of $8.87 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

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

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- 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 in this rate case. The ACC Staff recommends, among other things, a (i) $89.7 million revenue increase, (ii) average annual customer bill increase of 2.7%, (iii) 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) recovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project and (vi) recovery of the rate base effects of the construction and ongoing consideration of the deferral of the Ocotillo modernization project. RUCO recommends, among other things, a (i) $20.8 million revenue decrease, (ii) average annual customer bill decrease of 0.63%, (iii) return on equity of 8.74%, (iv) a 0% return on the increment of fair value rate base, (v) 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) recovery of the deferral and rate base effects of the construction and operating costs of the Ocotillo modernization project. Upon conclusion of APS's rate case and the completion of the deferral mechanisms, approximately $110 million of on-going operating costs related to the Four Corners SCR project and the Ocotillo modernization project will start to be reflected on APS's income statement.

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 Power Plant 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 Generating Station, 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.

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 schedule concluded on April 30, 2021. In May 2021, the ACC declined to re-open the evidentiary record in APS's pending rate case to take additional evidence on topics raised by certain ACC Commissioners, including adjustor cost recovery mechanisms.

On August 2, 2021, the Administrative Law Judge issued a Recommended Opinion and Order in APS's rate case (the "2019 Rate Case ROO"). The 2019 Rate Case ROO recommends, among other things, a (i) $111 million base revenue decrease, (ii) return on equity for original cost rate base of 9.16%, (iii) a 0.15% 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 0.10% reduction to return on equity resulting in an effective fair value return of 0.05%, (iv) 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) 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 and (vi) a 15% disallowance of annual amortization of Navajo Plant regulatory asset recovery. 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 Generating Station. These amounts would be recoverable from APS's customers through the RES. APS expects to file an exception regarding the disallowance of the SCR cost deferrals and plant investments that was recommended in the 2019 Rate Case ROO and APS is continuing to evaluate any additional exceptions it may file. The 2019 Rate Case ROO will be discussed at an upcoming ACC open meeting. APS cannot predict the outcome of this proceeding.

2016 Retail Rate Case Filing with the Arizona Corporation Commission

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates. On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, 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. The average annual customer bill impact under the 2017 Settlement Agreement was calculated as an increase of 3.28% (the average annual bill impact for a typical APS residential customer was calculated as an increase of 4.54%).

Other key provisions of the agreement include the following:

- an 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 Power Plant ("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 with the purpose of expanding access to rooftop solar for low and moderate income Arizonans, recoverable through the Arizona Renewable Energy Standard and Tariff ("RES"), to be no less than $10 million per year in capital costs, and not more than $15 million per year in capital costs;
- an increase to the per kWh cap for the environmental improvement surcharge from $0.00016 to $0.00050 and the addition of a balancing account;
- rate design changes, including:
    - a change in the on-peak time of use period from noon-7 p.m. to 3 p.m.-8 p.m. Monday through Friday, excluding holidays;
    - non-grandfathered distributed generation ("DG") customers would be required to select a rate option that has time of use rates and either a new grid access charge or demand component;
    - a Resource Comparison Proxy ("RCP") for exported energy of 12.9 cents per kWh in year one; and
- an agreement by APS not to pursue any new self-build generation (with certain exceptions) having an in-service date prior to January 1, 2022 (extended to December 31, 2027 for combined-cycle generating units), unless expressly authorized by the ACC.

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

On August 15, 2017, the ACC approved (by a vote of 4-1) the 2017 Settlement Agreement without material modifications. On August 18, 2017, the ACC issued a final written Opinion and Order reflecting its decision in APS's general retail rate case (the "2017 Rate Case Decision"), which is subject to requests for rehearing and potential appeal. The new rates went into effect on August 19, 2017.

On January 3, 2018, an APS customer filed a petition with the ACC that was determined by the ACC Staff to be a complaint filed pursuant to Arizona Revised Statute §40-246 (the "Complaint"). The Complaint was later amended alleging that the rates and charges in the 2017 Rate Case Decision are not just and reasonable. The ACC held a hearing on this matter, and the Administrative Law Judge issued a Recommended Opinion and Order recommending that the Complaint be dismissed. On July 3, 2019, the Administrative Law Judge issued an amendment to the Recommended Opinion and Order that incorporated the requirements of the rate review of the 2017 Rate Case Decision (see below discussion regarding the rate review). On July 10, 2019, the ACC adopted the Administrative Law Judge's amended Recommended Opinion and Order along with several ACC Commissioner amendments and an amendment incorporating the results of the rate review and resolved the Complaint.

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.

ACC Review of APS 2017 Rate Case Decision

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

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

- APS must file a rate case no later than October 31, 2019, using a June 30, 2019 test year;
- until the conclusion of the rate case being filed no later than October 31, 2019, APS must provide information on customer bills that shows how much a customer would pay on their most economical rate given their actual usage during each month;
- APS customers can switch rate plans during an open enrollment period of six months;
- APS must identify customers whose bills have increased by more than 9% and that are not on the most economical rate and provide such customers with targeted education materials and an opportunity to switch rate plans;
- APS must provide grandfathered net metering customers on legacy demand rates an opportunity to switch to another legacy rate to enable such customers to fully benefit from legacy net metering rates;
- APS must fund and implement a supplemental customer education and outreach program to be developed with and administered by ACC Staff and a third-party consultant; and
- APS must fund and organize, along with the third-party consultant, a stakeholder group to suggest better ways to communicate the impact of changes to adjustor cost recovery mechanisms (see below for discussion on cost recovery mechanisms), including more effective ways to educate customers on rate plans and to reduce energy usage.

APS filed its rate case on October 31, 2019 (see "2019 Retail Rate Case Filing with the Arizona Corporation Commission" above for more information). APS does not believe that the implementation of the other key provisions of the amended order regarding the rate review will have a material impact on its financial position, results of operations or cash flows.

On May 19, 2020, the ACC Staff filed a third-party consultant's report which evaluated the effectiveness of APS's customer outreach and education program related to the 2017 Rate Case Decision. On May 29, 2020, the Chairman of the ACC filed a letter with the ACC in response to this report and is alleging that APS is out of compliance with the 2017 Rate Case Decision and is over-earning. The Chairman proposed that the current rates should be classified as interim rates and customers held harmless if APS's activities have caused the rates set in the 2017 Rate Case Decision to not be just and reasonable. Also, on May 29, 2020, a second commissioner filed a letter with the ACC agreeing with the Chairman's assertions and further asserting that the 2017 Rate Case Decision should be re-opened. On June 18, 2020, at an ACC Open Meeting, the matters raised in these letters were discussed. The ACC did not vote to move forward with any adjustments to APS's current rates. On November 4, 2020, the ACC voted to administratively close this docket.

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 residential distributed energy requirement for 2020 contained in the RES rules. On September 23, 2020, the ACC approved the 2020 RES Implementation Plan, including a waiver of the residential distributed energy requirements for the 2020 implementation year. 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 residential distributed energy requirement for 2021 contained in the RES rules. 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 a waiver of the residential distributed energy requirements for the 2021 implementation year. As part of the approval, the ACC authorized APS to collect $68.3 million through the Renewable Energy Adjustment Charge to support APS's RES programs.

On May 21, 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. The adopted rules included substantial changes since the original Recommended Opinion and Order, and thus will require supplemental rulemaking before taking effect. APS cannot predict the outcome of this matter. 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's budget proposal supports existing approved projects and commitments and requests a permanent waiver of the residential and non-residential distributed energy requirements for 2022 contained in the RES rules. The ACC has not yet ruled on the 2022 RES Implementation Plan.

Demand Side Management Adjustor Charge. The ACC Electric Energy Efficiency Standards require APS to submit a DSM Plan annually for review by and approval of the ACC. Verified energy savings from APS's resource savings projects can be counted toward compliance with the Electric Energy Efficiency Standards; however, APS is not allowed to count savings from systems savings projects toward determination of the achievement of performance incentives, nor may APS include savings from these system savings projects in the calculation of its 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 demand side management portfolio to better meet system and customer needs by focusing on peak demand reductions, storage, load shifting and demand response programs in addition to traditional energy savings measures. The 2018 DSM Plan 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.

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 approved amount was the result of the kWh credit being based on historic consumption which was different than actual consumption in the refund period. The difference was recorded to the DSM balancing account and was included in the 2021 DSM Implementation Plan, which was approved by the ACC on June 13, 2021.

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 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 this request on June 8, 2021.

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 2021 and 2020 (dollars in thousands):

	Six Months Ended June 30,	
	2021	2020
Beginning balance	$ 175,835	$ 70,137
Deferred fuel and purchased power costs — current period	135,905	26,473
Amounts (charged) refunded to customers	(10,828)	4,815
Ending balance	$ 300,912	$ 101,425

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.

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

On November 30, 2020, APS filed its PSA rate for the PSA year beginning February 1, 2021. That rate was $0.003544 per kWh and 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, with 50% of the rate increase effective in April 2021 and the remaining 50% of the increase effective in November 2021. The PSA rate implemented on April 1, 2021 was $0.001544 per kWh and 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 will be implemented to a rate of $0.003544 per kWh and will consist 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, which is currently underway, to better understand the factors that contributed to the increase. APS cannot predict the outcome of this audit.

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. On December 29, 2020, the ACC Staff filed its report and recommended the storage costs be included in the PSA once the systems are in-service. On January 12, 2021, the ACC approved this application but did not rule on the 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 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 for qualified environmental improvements made during the prior calendar year, and the new charge becomes effective April 1 unless suspended by the ACC. There is an overall cap of $0.0005 per kWh (approximately $13 million to $14 million per year). APS's February 1, 2021 application requested an increase in the charge to

$10.3 million, or $1.5 million over the prior-period charge and it became effective with the first billing cycle in April 2021.

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 at FERC. Settlement or litigated resolution of disputed issues could require an extended period of time and could have a significant effect on the Retail Transmission Charges because any adjustment, though applied prospectively, may be calculated to account for previously over- or under-collected amounts. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected.

On March 7, 2018, APS made a filing to make modifications to its annual transmission formula to provide transmission customers the benefit of the reduced federal corporate income tax rate resulting from the Tax Cuts and Jobs Act ("Tax Act") beginning in its 2018 annual transmission formula rate update filing. These modifications were approved by FERC on May 22, 2018 and reduced APS's transmission rates compared to the rate that would have gone into effect absent these changes. On March 17, 2020, APS made a filing to make further modifications to its annual transmission formula to provide additional transparency for excess and deficient accumulated deferred income taxes resulting from the Tax Act, as well as for future local, state, and federal statutory tax rate changes. This filing is pending with FERC.

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 twelve-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 twelve-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 twelve-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 are currently 2.5 cents for both lost residential and non-residential kWh as set forth in the 2017 Settlement Agreement. The LFCR adjustment has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWhs lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. DG sales losses are determined from the metered output from the DG units.

On February 15, 2018, APS filed its 2018 annual LFCR adjustment, requesting that effective May 1, 2018, the LFCR be adjusted to $60.7 million. On February 6, 2019, the ACC approved the 2018 annual LFCR adjustment to become effective March 1, 2019. On February 15, 2019, APS filed its 2019 annual LFCR adjustment, requesting that effective May 1, 2019, the annual LFCR recovery amount be reduced to $36.2 million (a $24.5 million decrease from previous levels). On July 10, 2019, the ACC approved APS's 2019 LFCR adjustment as filed, effective with the next billing cycle of July 2019. On February 14, 2020, APS filed its 2020 annual LFCR adjustment, requesting that effective May 1, 2020, the annual LFCR recovery amount be reduced to $26.6 million (a $9.6 million decrease from previous levels). 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.

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

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

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

On August 13, 2018, APS filed a second request with the ACC that addressed the return of an additional $86.5 million in tax savings to customers related to the amortization of non-depreciation related excess deferred taxes previously collected from customers ("TEAM Phase II"). The ACC approved this request on March 13, 2019, effective the first billing cycle in April 2019 through the 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 will be recorded as a part of the balancing account and will be addressed for recovery as part of APS's 2019 ACC rate case. Both the timing of the reduction in revenues refunded through TEAM Phase II and the offsetting income tax benefit are recognized based upon our seasonal kWh sales pattern.

On April 10, 2019, APS filed a third request with the ACC that addressed the amortization of depreciation related excess deferred taxes over a 28.5-year period consistent with IRS normalization rules ("TEAM Phase III"). On October 29, 2019, the ACC approved TEAM Phase III providing both (i) a one-time bill credit of $64 million, which was credited to customers on their December 2019 bills, and (ii) a monthly bill credit effective the first billing cycle in December 2019 which will provide an additional benefit of $39.5 million to customers through December 31, 2020. 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 APS's 2019 pending 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 are recognized based upon APS's seasonal kWh sales pattern.

Net Metering

APS's 2017 Rate Case Decision provides that payments by utilities for energy exported to the grid from DG solar facilities will be determined using a RCP methodology, a method that is based on the most recent five-year rolling average price that APS pays for utility-scale solar projects, while a forecasted avoided cost methodology is being developed. The price established by this RCP method will be updated annually (between general retail rate cases) but will not be decreased by more than 10% per year. Once the avoided cost methodology is developed, the ACC will determine in APS's subsequent rate cases which method (or a combination of methods) is appropriate to determine the actual price to be paid by APS for exported distributed energy.

In addition, the ACC made the following determinations:

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

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future general retail rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies. A first-year export energy price of 12.9 cents per kWh was included in the 2017 Settlement Agreement and became effective on September 1, 2017.

In accordance with the 2017 Rate Case Decision, APS filed its request for a third-year export energy price of 10.5 cents per kWh on May 1, 2019. This price also reflects the 10% annual reduction discussed above. The new rate rider became effective on October 1, 2019. 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. APS's export energy price will remain at 10.5 cents per kWh until October 1, 2021.

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

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

Subpoena from 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.

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

On February 7, 2017, Burns opened a new ACC docket and indicated that its purpose is to study and rectify problems with transparency and disclosure regarding financial contributions from regulated monopolies or other stakeholders who may appear before the ACC that may directly or indirectly benefit an ACC Commissioner, a candidate for ACC Commissioner, or key ACC Staff. As part of this docket, Burns set March 24, 2017 as a deadline for the production of all information previously requested through the subpoenas.

Neither APS nor Pinnacle West produced the information requested and instead objected to the subpoena. On March 10, 2017, Burns filed suit against APS and Pinnacle West in the Superior Court of Arizona for Maricopa County in an effort to enforce his subpoenas. On March 30, 2017, APS filed a motion to dismiss Burns' suit against APS and Pinnacle West. In response to the motion to dismiss, the court stayed the suit and ordered Burns to file a motion to compel the production of the information sought by the subpoenas with the ACC. On June 20, 2017, the ACC denied the motion to compel.

On August 4, 2017, Burns amended his complaint to add all of the ACC Commissioners and the ACC itself as defendants. All defendants moved to dismiss the amended complaint. On February 15, 2018, the Superior Court dismissed Burns' amended complaint. On March 6, 2018, Burns filed an objection to the proposed final order from the Superior Court and a motion to further amend his complaint. The Superior Court permitted Burns to amend his complaint to add a claim regarding his attempted investigation into whether his fellow commissioners should have been disqualified from voting on APS's 2017 rate case. Burns filed his second amended complaint, and all defendants filed responses opposing the second amended complaint and requested that it be dismissed. Oral argument occurred in November 2018 regarding the motion to dismiss. On December 18, 2018, the trial court granted the defendants' motions to dismiss and entered final judgment on January 18, 2019.

On February 13, 2019, Burns filed a notice of appeal. On July 12, 2019, Burns filed his opening brief in the Arizona Court of Appeals. APS filed its answering brief on October 21, 2019. The Arizona Court of Appeals originally granted the request for oral argument; however, on March 31, 2020, the court vacated the date scheduled for oral argument given the COVID-19 pandemic. The court determined that the matter could be submitted without oral argument and has taken the matter under advisement and will issue a decision without oral argument.

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. Both APS and the ACC filed responses opposing the motion and asserting that the matter is moot. 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 grant of review by the Arizona Supreme Court is discretionary. Pinnacle West and APS cannot predict the outcome of this matter.

Information Requests from Arizona Corporation Commissioners

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

Energy Modernization Plan

On January 30, 2018, former ACC Commissioner Tobin proposed the Energy Modernization Plan, which consisted of a series of energy policies tied to clean energy sources such as energy storage, biomass, energy efficiency, electric vehicles, and expanded energy planning through the integrated resource plan ("IRP") process. In August 2018, the ACC directed ACC Staff to open a new rulemaking docket which will address a wide range of energy issues, including the Energy Modernization Plan proposals. The rulemaking will consider possible modifications to existing ACC rules, such as the RES, Electric and Gas Energy Efficiency Standards, Net Metering, Resource Planning, and the Biennial Transmission Assessment, as well as the development of new rules regarding forest bioenergy, electric vehicles, interconnection of distributed generation, baseload security, blockchain technology and other technological developments, retail competition, and other energy-related topics.

On April 25, 2019, the ACC Staff issued an initial set of draft energy rules and held various workshops to incorporate feedback from stakeholders and ACC Commissioners from April 2019 through July 2020. At the March 11-12, 2020 workshop, the ACC Staff committed to filing a final draft of proposed rules by 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 is defined as a clean energy resource. The proposed rules also require 50% of retail energy served be renewable by the end of 2035. A new energy efficiency standard was not included in the proposed rules. APS would be required to obtain approval of its action plan included in its IRP and seek recovery of prudently incurred costs in a rate process. If approved by the ACC Commissioners, the rules would require 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, the ACC Staff proposed changing the IRP planning horizon from 15 years to 10 years.

The ACC discussed the final draft energy rules at several different meetings in 2020. On October 14, 2020, the ACC passed one amendment to ACC Staff's final draft energy rules that would have required electric utilities to obtain 35% of peak load (as measured in 2020) by 2030 from DSM resources, including traditional energy efficiency, demand response and other programs aimed at reducing energy usage, peak demand management and load shifting. This standard aligned with the proposed rules' three-year resource planning cycle and allowed recovery of costs through existing mechanisms until the ACC issues a decision in a future rate proceeding. On October 29, 2020, the ACC approved an amendment that would have required electric utilities to reduce their carbon emissions over 2016-2018 levels by 50% by 2032; 75% by 2040; and 100% by 2050. The ACC also approved an amendment that required utilities to install energy storage systems with an aggregate capacity equal to 5% of each utility's 2020 peak demand by 2035, of which 40% must be derived from customer-owned or customer-leased distributed storage. Another approved amendment modified the resource planning process, including requirements for the ACC to approve a utility's load forecast and resource plan, and for a utility to perform an all-source request for information to guide its resource plan. 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 May 2021, the ACC adopted clean energy rules based on a series of ACC amendments. The adopted rules include 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 differ substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures will be required before the rules become effective. 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. In March of 2018, the ACC reviewed the 2017 IRPs of its jurisdictional utilities and voted to not acknowledge any of the plans. APS does not believe that this lack of acknowledgment will have a material impact on our financial position, results of operations or cash flows. Based on an ACC decision, APS was originally required to file its next IRP by April 1, 2020. On February 20, 2020, the ACC extended the deadline for all utilities to file their IRP's from April 1, 2020 to June 26, 2020. 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 March 2021, the ACC Staff requested additional time to prepare its assessment of utility IRPs. The ACC has taken no action on APS's IRP. APS cannot predict the outcome of this matter. 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 power purchase agreements 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. APS is evaluating how the revised regulations may impact its operations.

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. ACC stakeholder meetings were held in September 2019, October 2019 and January 2020 regarding 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 threshold (June 1 – October 15) for disconnection moratoriums. The ACC held two public comment sessions on the draft rules and will conduct a final vote before the rules become effective. The Summer Disconnection Moratorium will remain in effect until the ACC formalizes the final rules package.

Due to the COVID-19 pandemic, APS voluntarily suspended disconnections of customers for nonpayment and waived late payment fees beginning March 13, 2020 until December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021 and customers were automatically placed on eight-month payment arrangements if they had past due balances at the end of the disconnection period of $75 or greater. APS will continue to waive late payment fees until October 15, 2021. APS has experienced and is continuing to experience an increase in bad debt expense associated with the COVID-19 pandemic. See "COVID-19 Pandemic" above for more information.

Retail Electric Competition Rules

On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. An ACC special open meeting workshop was held on December 3, 2018. No substantive action was taken, but interested parties were asked to submit written comments and respond to a list of questions from ACC Staff. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACC's retail electric competition rules. Interested parties filed comments to the ACC Staff report and a stakeholder meeting and workshop to discuss the retail electric competition rules was held on July 30, 2019. ACC Commissioners submitted additional questions regarding this matter. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACC's retail electric competition rules. The ACC held a workshop on February 25-26, 2020 on further consideration and discussion of the 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 Commissioners are continuing to explore the retail electric competition rules. APS cannot predict whether these efforts will result in any changes and, if changes to the rules results, what impact these rules would have on APS.

Rate Plan Comparison Tool 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. APS developed a new tool for comparing customers' rate plan options. APS had an independent third party verify that the new rate comparison tool works correctly. In February 2020, APS launched the new online rate comparison tool, which is now available for its customers. 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 if any action will be taken by the ACC at this time.

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, $24 million of which is being 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. Consistent with the 2017 Rate Case Decision, the request was narrow in scope and addressed only costs associated with this specific environmental compliance equipment. The SCR Adjustment request provided that there would be a $67.5 million annual revenue impact that would be applied as a percentage of base rates for all applicable customers. Also, as provided for in the 2017 Rate Case Decision, APS requested that the adjustment become effective no later than January 1, 2019. The hearing for this matter occurred in September 2018. At the hearing, APS accepted ACC Staff's recommendation of a lower annual revenue impact of approximately $58.5 million. The Administrative Law Judge issued a Recommended Opinion and Order finding that the costs for the SCR project were prudently incurred and recommending authorization of the $58.5 million annual revenue requirement related to the installation and operation of the SCRs. Exceptions to the Recommended Opinion and Order were filed by the parties and intervenors on December 7, 2018. The ACC has not issued a decision on this matter. APS included the costs for the SCR project in the retail rate base in its 2019 Retail Rate Case filing with the ACC. On March 18, 2020, the ACC agreed to take administrative notice to include in the pending rate case portions of the record in this prior proceeding that are relevant to the SCRs.

On August 2, 2021, the 2019 Rate Case ROO recommended a disallowance of approximately $399 million of SCR plant investments and $61 million of SCR cost deferrals. The ACC has not issued a decision on this matter, but if the recommendation regarding the Four Corners SCR project in the 2019 Rate Case ROO is adopted and ordered by the ACC, APS would be required to record a write-off related to the SCR cost deferrals. As of June 30, 2021, the SCR cost deferral balance is approximately $75 million net of accumulated deferred income taxes. In addition, if the recommendation regarding the SCR plant investment disallowance in the 2019 Rate Case ROO is adopted and ordered by the ACC, the amount of any loss will be determined based on the value of the SCR plant investment assets at the time the disallowance is probable and estimable and could also be affected by other regulatory and legal considerations. As of June 30, 2021, the value of the SCR plant investments is approximately $320 million, net of accumulated deferred income taxes. If a disallowance of all or a portion of the SCR plant investments is determined to be estimable and probable, or if regulatory recovery of all or a portion of the deferred costs is determined to no longer be probable, it is reasonably possible that APS will recognize a material loss on the SCR investments and cost deferrals. For the period ended June 30, 2021, based on the fact that the 2019 Rate Case ROO is not a final decision and that APS intends to file exceptions to the 2019 Rate Case ROO related to the recommended disallowance of SCR plant investments and cost deferrals, among other factors, APS has not recorded any adjustments to write-off or write-down the SCR plant investments or cost deferrals. The pollution control assets are used and useful and are required to operate Four Corners and APS believes that these SCR investments were prudently incurred. APS cannot predict the final outcome of the decision on this matter nor reasonably estimate the amount of any potential loss.

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. Cholla Unit 4 was retired on December 24, 2020.

Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS has been recovering a return on and of the net book value of the unit in base rates. Pursuant to the 2017 Settlement Agreement described above, APS will be allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs ($48.9 million as of June 30, 2021), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. The 2017 Settlement Agreement also shortened the depreciation lives of Cholla Units 1 and 3 to 2025.

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.

APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant over its previously estimated life through 2026. APS will seek continued recovery in rates for the book value of its remaining investment in the plant ($67 million as of June 30, 2021) plus a return on the net book value as well as other costs related to retirement and closure, including the Navajo coal reclamation regulatory asset ($17.5 million as of June 30, 2021). APS believes it will be allowed recovery of the net book value, retirement and closure costs, in addition to a return on its investment. In accordance with GAAP, in the second quarter of 2017, APS's remaining net book value of its interest in the Navajo Plant was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of this interest, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted. On August 2, 2021, the 2019 Rate Case ROO recommended that APS record 15% of the annual amortization of the regulatory asset as a non-operating expense. If the recommendation regarding the Navajo Plant in the 2019 Rate Case ROO is adopted and ordered by the ACC, APS does not expect this to have a material impact on its financial statements.

Regulatory Assets and Liabilities

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

	Amortization Through	June 30, 2021 Current	June 30, 2021 Non-Current	December 31, 2020 Current	December 31, 2020 Non-Current
Pension	(a)	$ —	$ 496,372	$ —	$ 469,953
Deferred fuel and purchased power (b) (c)	2022	300,912	—	175,835	—
Income taxes — allowance for funds used during construction ("AFUDC") equity	2051	7,169	161,279	7,169	158,776
Retired power plant costs	2033	28,182	100,123	28,181	114,214
Ocotillo deferral	N/A	—	124,919	—	95,723
SCR deferral	N/A	—	95,171	—	81,307
Deferred property taxes	2027	8,569	45,342	8,569	49,626
Lost fixed cost recovery (b)	2022	53,087	—	41,807	—
Deferred compensation	2036	—	35,806	—	36,195
Four Corners cost deferral	2024	8,077	20,037	8,077	24,075
Income taxes — investment tax credit basis adjustment	2049	1,113	23,807	1,113	24,291
Palo Verde VIEs (Note 6)	2046	—	21,174	—	21,255
Coal reclamation	2026	1,068	16,465	1,068	16,999
Loss on reacquired debt	2038	1,648	10,128	1,689	10,877
Mead-Phoenix transmission line contributions in aid of construction ("CIAC")	2050	332	9,214	332	9,380
Tax expense adjustor mechanism (b)	2021	7,956	—	6,226	—
Demand side management (b)	2022	—	7,269	—	7,268
Tax expense of Medicare subsidy	2024	1,235	3,167	1,235	3,704
TCA balancing account (b)	2023	—	1,903	—	—
Deferred fuel and purchased power — mark-to-market (Note 7)	2024	—	—	3,341	9,244
PSA interest	2022	133	—	4,355	—
Other	Various	1,321	1,801	2,716	1,100
Total regulatory assets (d)		$ 420,802	$ 1,173,977	$ 291,713	$ 1,133,987

(a) This asset represents the future recovery of pension benefit obligations through retail rates. If these costs are disallowed by the ACC, this regulatory asset would be charged to other comprehensive income ("OCI") and result in lower future revenues. See Note 5.
(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."

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

		June 30, 2021		December 31, 2020	
	Amortization Through	Current	Non-Current	Current	Non-Current
Excess deferred income taxes — ACC - Tax Act (a)	2046	$ 41,381	$ 993,982	$ 41,330	$ 1,012,583
Excess deferred income taxes — FERC - Tax Act (a)	2058	7,240	225,995	7,240	229,147
Asset retirement obligations	2057	—	567,900	—	506,049
Other postretirement benefits	(d)	47,798	314,218	37,705	349,588
Removal costs	(c)	69,348	61,601	52,844	103,008
Deferred fuel and purchased power — mark-to-market (Note 7)	2024	82,082	27,305	—	—
Income taxes — change in rates	2050	2,839	65,319	2,839	66,553
Four Corners coal reclamation	2038	5,461	49,904	5,460	49,435
Income taxes — deferred investment tax credit	2049	2,231	47,677	2,231	48,648
Spent nuclear fuel	2027	6,510	41,815	6,768	44,221
Renewable energy standard (b)	2022	30,665	—	39,442	103
Property tax deferral	N/A	—	16,188	—	13,856
Demand side management (b)	2022	3,149	12,457	10,819	—
Sundance maintenance	2031	556	12,312	2,989	11,508
FERC transmission true up	2023	7,547	3,511	6,598	3,008
TCA balancing account (b)	2023	10,750	159	2,902	4,672
Tax expense adjustor mechanism (b) (e)	2021	7,148	—	7,089	—
Deferred gains on utility property	2022	2,423	333	2,423	1,544
Active union medical trust	N/A	—	2,347	—	6,057
Other	Various	484	289	409	189
Total regulatory liabilities		$ 327,612	$ 2,443,312	$ 229,088	$ 2,450,169

(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) Pursuant to Decision 77852, the ACC has authorized APS to return to customers up to $7 million of liability recorded to the TEAM balancing account through December 31, 2021. Should new base rates become effective prior to December 31, 2021, any remaining unreturned balance is anticipated to be included in the new base rates.

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.

Under the HRA, included in the other postretirement benefit plan, the Company provides a subsidy to retirees to defray the cost of a Medicare supplemental policy. In prior years, we had been assuming a 4.75% escalation of these benefits; however, actual escalation has been significantly less than this assumption. Accordingly, during 2020 and for future periods, the escalation assumption was reduced to 2.00%. This escalation factor assumption change, among other factors, resulted in an increase in the over-funded status of the other postretirement benefit plan as of December 31, 2020. As a result, on January 4, 2021, we initiated the transfer of approximately $106 million of assets from the other postretirement benefit plan into the Active Union Employee Medical Account. The Active Union Employee Medical Account is an existing trust account that holds assets restricted for paying active union employee medical costs (see Note 12). The transfer of other postretirement benefit plan assets into the Active Union Employee Medical Account permits access to approximately $106 million of assets for the sole purpose of paying active union employee medical benefits. This transfer of assets into the Active Union Employee Medical Account is consistent with the terms of a similar 2018 transaction.

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 June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020	2021	2020	2021	2020
Service cost — benefits earned during the period	$ 14,939	$ 13,859	$ 30,618	$ 28,116	$ 4,341	$ 5,401	$ 8,898	$ 11,118
Non-service costs (credits):								
Interest cost on benefit obligation	24,614	29,522	49,283	59,283	4,095	6,417	8,257	12,929
Expected return on plan assets	(50,706)	(46,915)	(101,314)	(93,721)	(10,361)	(10,019)	(20,722)	(20,038)
Amortization of:								
Prior service credit	—	—	—	—	(9,427)	(9,394)	(18,854)	(18,788)
Net actuarial loss (gain)	3,989	8,295	7,974	17,306	(2,641)	—	(5,046)	—
Net periodic benefit cost/(benefit)	$ (7,164)	$ 4,761	$ (13,439)	$ 10,984	$ (13,993)	$ (7,595)	$ (27,467)	$ (14,779)
Portion of cost/(benefit) charged to expense	$ (8,614)	$ 271	$ (16,625)	$ 1,613	$ (9,608)	$ (5,056)	$ (19,136)	$ (10,512)

Contributions

We have not made voluntary contributions to our pension plan year-to-date in 2021. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to $100 million in 2021 and zero in 2022 and 2023. We do not expect to make any contributions over this period to our other postretirement benefit plans.

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. Prior to April 1, 2021, the lease terms allowed APS the right to retain the assets through 2023 under one lease and 2033 under the other two leases. On April 1, 2021, APS executed an amended lease agreement with one of the VIE lessor trust entities relating to the lease agreement with the term ending in 2023. The amendment extends the lease term for this lease through 2033 and changes the lease payment. As a result of this amendment, APS will now retain the assets through 2033 under all three lease agreements. APS will be required to make payments relating to the three leases in total of approximately $21 million annually for the period 2021 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 and six months ended June 30, 2021 of $4 million and $9 million, respectively, and for the three and six months ended June 30, 2020 of $5 million and $10 million, respectively, entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

Our Condensed Consolidated Balance Sheets at June 30, 2021 and December 31, 2020 include the following amounts relating to the VIEs (dollars in thousands):

	June 30, 2021	December 31, 2020
Palo Verde sale leaseback property, plant and equipment, net of accumulated depreciation	$ 96,101	$ 98,036
Equity — Noncontrolling interests	117,275	119,290

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 $307 million beginning in 2021, 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 in 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.

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**	**June 30, 2021**	**December 31, 2020**
Power	GWh	368	368
Gas	Billion cubic feet	189	205

Gains and Losses from Derivative Instruments

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

Commodity Contracts	Financial Statement Location	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Loss Reclassified from Accumulated OCI into Income (Effective Portion Realized) (a)	Fuel and purchased power (b)	$ —	$ (349)	$ —	$ (763)

(a) During the three and six months ended June 30, 2021 and 2020, we had no gains or losses reclassified from accumulated OCI to earnings related to discontinued cash flow hedges.
(b) Amounts are before the effect of PSA deferrals.

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

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

Commodity Contracts	Financial Statement Location	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Net Gain (Loss) Recognized in Income	Fuel and purchased power (a)	$ 95,116	$ (4,894)	$ 121,975	$ (34,971)

(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.

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 and other assets lines of our Condensed Consolidated Balance Sheets.

As of June 30, 2021: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheets
Current assets	$ 83,677	$ (1,368)	$ 82,309	$ —	$ 82,309
Investments and other assets	27,305	—	27,305	—	27,305
Total assets	110,982	(1,368)	109,614	—	109,614
Current liabilities	(1,595)	1,368	(227)	(1,285)	(1,512)
Deferred credits and other	—	—	—	—	—
Total liabilities	(1,595)	1,368	(227)	(1,285)	(1,512)
Total	$ 109,387	$ —	$ 109,387	$ (1,285)	$ 108,102

(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 that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions or collateral posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $1,285.

As of December 31, 2020: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheets
Current assets	$ 5,870	$ (2,939)	$ 2,931	$ —	$ 2,931
Investments and other assets	3,150	(1,332)	1,818	—	1,818
Total assets	9,020	(4,271)	4,749	—	4,749
Current liabilities	(9,211)	2,939	(6,272)	(1,285)	(7,557)
Deferred credits and other	(12,394)	1,332	(11,062)	—	(11,062)
Total liabilities	(21,605)	4,271	(17,334)	(1,285)	(18,619)
Total	$ (12,585)	$ —	$ (12,585)	$ (1,285)	$ (13,870)

(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 $1,285.

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 June 30, 2021, we have two counterparties for which our exposure represents approximately 35% of Pinnacle West's $110 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).

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

	June 30, 2021
Aggregate fair value of derivative instruments in a net liability position	$ 1,595
Cash collateral posted	—
Additional cash collateral in the event credit-risk-related contingent features were fully triggered	—

We also have energy-related non-derivative instrument contracts with investment grade credit-related contingent features, which could also require us to post additional collateral of approximately $87 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 six claims pursuant to the terms of the August 18, 2014 settlement agreement, for six separate time periods during July 1, 2011 through June 30, 2019. The DOE has approved and paid $99.7 million for these claims (APS's share is $29.0 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 Rate Case Decision, this regulatory liability is being refunded to customers (see Note 4). On November 2, 2020, APS filed its seventh 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 15, 2021, the DOE approved a payment of $12.1 million (APS's share is $3.5 million) and on April 16, 2021, 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 $22.4 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 $63.3 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 June 30, 2021, our fuel and purchased power commitments have increased from the information provided in our 2020 Form 10-K. The increase is primarily due to new purchased power and energy storage commitments of approximately $624 million. The majority of the changes relate to 2026 and thereafter.

Other than the item described above, there have been no material changes, as of June 30, 2021, outside the normal course of business in contractual obligations from the information provided in our 2020 Form 10-K. See Note 3 for discussion regarding changes in our short-term and long-term debt obligations. See Note 6 for discussion regarding changes to our contractual obligations related to the Palo Verde sale leaseback transactions.

Superfund-Related Matters

The Comprehensive Environmental Response Compensation and Liability Act ("Superfund" or "CERCLA") establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who released, generated, transported to or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible ("PRPs"). PRPs may be strictly, and often are jointly and severally, liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 ("OU3") in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study ("RI/FS"). Based upon discussions between the OU3 working group parties and EPA, along with the results of recent technical analyses prepared by the OU3 working group to supplement the RI/FS for OU3, APS anticipates finalizing the RI/FS during the fourth quarter of 2021. We estimate that our costs related to this investigation and study will be approximately $3 million. We anticipate incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

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

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, $24 million of which is being returned to customers as restitution.

Four Corners SCR Cost Recovery

As part of APS's rate case filing in 2019, APS included recovery of the deferral and rate base effects of the Four Corners SCR project. On August 2, 2021, the 2019 Rate Case ROO recommended a disallowance of approximately $399 million of SCR plant investments and $61 million of SCR cost deferrals. The ACC has not issued a decision on this matter, but if the recommendation regarding the Four Corners SCR project in the 2019 Rate Case ROO is adopted and ordered by the ACC, APS would be required to record a write-off related to the SCR cost deferrals. As of June 30, 2021, the SCR cost deferral balance is approximately $75 million net of accumulated deferred income taxes. In addition, if the recommendation regarding the SCR plant investment disallowance in the 2019 Rate Case ROO is adopted and ordered by the ACC, the amount of any loss will be determined based on the value of the SCR plant investment assets at the time the disallowance is probable and estimable and could also be affected by other regulatory and legal considerations. As of June 30, 2021, the value of the SCR plant investments is approximately $320 million, net of accumulated deferred income taxes. If a disallowance of all or a portion of the SCR plant investments is determined to be estimable and probable, or if regulatory recovery of all or a portion of the deferred costs is determined to no longer be probable, it is reasonably possible that APS will recognize a material loss on the SCR investments and cost deferrals. For the period ended June 30, 2021, based on the fact that the 2019 Rate Case ROO is not a final decision and that APS intends to file exceptions to the 2019 Rate Case ROO related to the recommended disallowance of SCR plant investments and cost deferrals, among other factors, APS has not recorded any adjustments to write-off or write-down the SCR plant investments or cost deferrals. The pollution control assets are used and useful and are required to operate Four Corners and APS believes that these SCR investments were prudently incurred. APS cannot predict the final outcome of the decision on this matter nor reasonably estimate the amount of any potential loss.

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. In addition, EPA issued a final rule for Regional Haze compliance at Cholla that does not involve the installation of new pollution controls and that will replace an earlier BART determination for this facility. See below for details of the Cholla BART approval.

Four Corners. Based on EPA's final standards, APS's 63% share of the cost of required controls for Four Corners Units 4 and 5 was approximately $400 million, which has been incurred. In addition, APS and El Paso Electric Company ("El Paso") entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in Four Corners Units 4 and 5. 4CA purchased the El Paso interest on July 6, 2016. Navajo Transitional Energy Company, LLC ("NTEC") purchased the interest from 4CA on July 3, 2018. See "Four Corners — 4CA Matter" below for a discussion of the NTEC purchase. The cost of the pollution controls related to the 7% interest is approximately $45 million, which was assumed by NTEC through its purchase of the 7% interest.

Cholla. In early 2017, EPA approved a final rule containing a revision to Arizona's State Implementation Plan ("SIP") for Cholla that implemented BART requirements for this facility, which did not require the installation of any new pollution control capital improvements. In conjunction with the closure of Cholla Unit 2 in 2015, APS has committed to ceasing coal combustion within Units 1 and 3 by April 2025. PacifiCorp retired Cholla Unit 4 at the end of 2020. (See "Cholla" in Note 4 for information regarding future plans for Cholla and details related to the resulting regulatory asset).

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

Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

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

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

- Based on an August 21, 2018 D.C. Circuit decision, which vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments, EPA recently proposed corresponding changes to federal CCR regulations. On July 29, 2020, EPA took final action on new regulations establishing revised deadlines for initiating the closure of unlined CCR surface impoundments, April 11, 2021 at the latest. All APS disposal units subject to these closure requirements were closed as of April 11, 2021.

- 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.

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 $27 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 initiated an assessment of corrective measures on January 14, 2019 and expects such assessment will continue through late-2021. As part of this assessment, APS continues to gather additional groundwater data and perform remedial evaluations as to the CCR disposal units at Cholla and Four Corners undergoing corrective action. In addition, APS will solicit input from the public, host public hearings, and select remedies as part of this process. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from $10 million to $15 million, which would be incurred over 30 years. The analysis needed to perform a similar cost estimate for Cholla remains ongoing at this time. As APS continues to implement the CCR rule's corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until we have fully completed the corrective action assessment process, we cannot predict any ultimate impacts to the Company; however, at this time we do not believe the cost estimates for Cholla and any potential change to the cost estimate for Four Corners would have a material impact on our financial position, results of operations or cash flows.

Clean Power Plan/Affordable Clean Energy Regulations. On June 19, 2019, EPA took final action on its proposals to repeal EPA's 2015 Clean Power Plan ("CPP") and replace those regulations with a new rule, the Affordable Clean Energy ("ACE") regulations. EPA originally finalized the CPP on August 3, 2015, and 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. 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 in response to the court's recent ACE decision.

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. On January 22, 2021, the environmental groups filed a petition for review of the EAB's decision with the U.S. Court of Appeals for the Ninth Circuit. The September 2019 permit remains in effect pending this appeal. The parties are presently engaged in mediation to settle this dispute. We cannot predict the outcome of this appeal proceeding, the ongoing mediation, and, if such appeal is successful, whether that outcome 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 June 30, 2021, the note has a remaining balance of $18 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.

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

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 June 30, 2021, standby letters of credit totaled $5.3 million and would have expired in 2021, subsequently in April of 2021 an extension was effective that reset the expiration dates to 2022. As of June 30, 2021, surety bonds expiring through 2022 totaled $16 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 June 30, 2021. 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 June 30, 2021 are immaterial in amount (approximately $2 million) and the PTC Guarantees (approximately $38 million as of June 30, 2021) are currently expected to be terminated ten years following the commercial operation date of the applicable project.

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 June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Other income:				
Interest income	$ 1,687	$ 2,755	$ 3,635	$ 6,032
Investment gains - net	—	2,826	—	2,826
Debt return on Four Corners SCR deferrals (Note 4)	4,089	4,249	8,175	7,389
Debt return on Ocotillo modernization project (Note 4)	6,391	6,703	12,783	12,847
Miscellaneous	40	137	43	145
Total other income	$ 12,207	$ 16,670	$ 24,636	$ 29,239
Other expense:				
Non-operating costs	(4,102)	(2,290)	(6,039)	(4,948)
Investment gains (losses) — net	(431)	—	(774)	60
Miscellaneous	(651)	(1,746)	(2,224)	(3,932)
Total other expense	$ (5,184)	$ (4,036)	$ (9,037)	$ (8,820)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Other income:				
Interest income	$ 1,047	$ 2,183	$ 2,528	$ 4,524
Debt return on Four Corners SCR deferrals (Note 4)	4,089	4,249	8,175	7,389
Debt return on Ocotillo modernization project (Note 4)	6,391	6,703	12,783	12,847
Miscellaneous	36	137	37	145
Total other income	$ 11,563	$ 13,272	$ 23,523	$ 24,905
Other expense:				
Non-operating costs	(3,615)	(2,113)	(5,392)	(4,595)
Miscellaneous	(646)	(1,746)	(2,219)	(3,932)
Total other expense	$ (4,261)	$ (3,859)	$ (7,611)	$ (8,527)

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 June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Net income attributable to common shareholders	$ 215,697	$ 193,585	$ 251,338	$ 223,578
Weighted average common shares outstanding — basic	112,882	112,638	112,855	112,616
Net effect of dilutive securities:				
Contingently issuable performance shares and restricted stock units	341	241	303	255
Weighted average common shares outstanding — diluted	113,223	112,879	113,158	112,871
Earnings per weighted-average common share outstanding				
Net income attributable to common shareholders — basic	$ 1.91	$ 1.72	$ 2.23	$ 1.99
Net income attributable to common shareholders — diluted	$ 1.91	$ 1.71	$ 2.22	$ 1.98

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 2020 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.

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

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.

Fair Value Tables

The following table presents the fair value at June 30, 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	$ —	$ 84,594	$ 26,388	$ (1,368)	(a)	$ 109,614
Nuclear decommissioning trust:						
Equity securities	22,749	—	—	(9,506)	(b)	13,243
U.S. commingled equity funds	—	—	—	702,836	(c)	702,836
U.S. Treasury debt	167,584	—	—	—		167,584
Corporate debt	—	150,681	—	—		150,681
Mortgage-backed securities	—	119,481	—	—		119,481
Municipal bonds	—	59,876	—	—		59,876
Other fixed income	—	9,387	—	—		9,387
Subtotal nuclear decommissioning trust	190,333	339,425	—	693,330		1,223,088
Other special use funds:						
Equity securities	19,904	—	—	952	(b)	20,856
U.S. Treasury debt	324,418	—	—	—		324,418
Municipal bonds	—	13,162	—	—		13,162
Subtotal other special use funds	344,322	13,162	—	952		358,436
Total assets	$ 534,655	$ 437,181	$ 26,388	$ 692,914		$ 1,691,138
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (1,586)	$ (9)	$ 83	(a)	$ (1,512)

(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.

The following table presents the fair value at December 31, 2020 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	$ —	$ 9,016	$ 4	$ (4,271)	(a)	$ 4,749
Nuclear decommissioning trust:						
Equity securities	29,796	—	—	(17,828)	(b)	11,968
U.S. commingled equity funds	—	—	—	610,055	(c)	610,055
U.S. Treasury debt	164,514	—	—	—		164,514
Corporate debt	—	149,509	—	—		149,509
Mortgage-backed securities	—	99,623	—	—		99,623
Municipal bonds	—	89,705	—	—		89,705
Other fixed income	—	13,061	—	—		13,061
Subtotal nuclear decommissioning trust	194,310	351,898	—	592,227		1,138,435
Other special use funds:						
Equity securities	37,337	—	—	504	(b)	37,841
U.S. Treasury debt	203,220	—	—	—		203,220
Municipal bonds	—	13,448	—	—		13,448
Subtotal other special use funds	240,557	13,448	—	504		254,509
Total assets	$ 434,867	$ 374,362	$ 4	$ 588,460		$ 1,397,693
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (20,498)	$ (1,107)	$ 2,986	(a)	$ (18,619)

(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 $18.2 million as of June 30, 2021 and $27.1 million as of December 31, 2020, 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 mine 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 2020 and 2019, APS was reimbursed $14 million and $15 million, respectively, for prior year active union employee medical claims from the active union employee medical account. The account is invested primarily in fixed income securities. In accordance with the ratemaking treatment, APS has deferred the unrealized gains and losses (including credit losses) in other regulatory liabilities. Activities relating to active union employee medical account investments are included within the other special use funds in the table below. On January 4, 2021, an additional $106 million of investments were transferred from APS other postretirement benefit trust assets into the active union employee medical account (see Note 5).

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):

	June 30, 2021					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 725,585	$ 19,904	$ 745,489		$ 510,432	$ —
Available for sale-fixed income securities	507,009	337,580	844,589	(a)	31,269	(1,357)
Other	(9,506)	952	(8,554)	(b)	—	—
Total	$ 1,223,088	$ 358,436	$ 1,581,524		$ 541,701	$ (1,357)

(a) As of June 30, 2021, the amortized cost basis of these available-for-sale investments is $815 million.
(b) Represents net pending securities sales and purchases.

	December 31, 2020					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 639,851	$ 37,337	$ 677,188		$ 421,666	$ —
Available for sale-fixed income securities	516,412	216,668	733,080	(a)	46,581	(398)
Other	(17,828)	504	(17,324)	(b)	—	—
Total	$ 1,138,435	$ 254,509	$ 1,392,944		$ 468,247	$ (398)

(a) As of December 31, 2020, the amortized cost basis of these available-for-sale investments is $687 million.
(b) Represents net pending securities sales and purchases.

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 June 30,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2021			
Realized gains	$ 1,406	$ —	$ 1,406
Realized losses	(1,146)	—	(1,146)
Proceeds from the sale of securities (a)	190,340	17,524	207,864
2020			
Realized gains	$ 4,500	$ —	$ 4,500
Realized losses	(1,621)	—	(1,621)
Proceeds from the sale of securities (a)	176,942	19,830	196,772

(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.

	Six Months Ended June 30,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2021			
Realized gains	$ 4,374	$ —	$ 4,374
Realized losses	(5,294)	—	(5,294)
Proceeds from the sale of securities (a)	425,068	162,774	587,842
2020			
Realized gains	$ 7,813	$ —	$ 7,813
Realized losses	(3,848)	—	(3,848)
Proceeds from the sale of securities (a)	355,138	36,721	391,859

(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 June 30, 2021, is as follows (dollars in thousands):

	Nuclear Decommissioning Trust	Coal Reclamation Escrow Account	Active Union Employee Medical Account	Total
Less than one year	$ 28,151	$ 26,123	$ 40,263	$ 94,537
1 year – 5 years	133,054	35,880	162,728	331,662
5 years – 10 years	131,462	2,676	61,288	195,426
Greater than 10 years	214,342	8,622	—	222,964
Total	$ 507,009	$ 73,301	$ 264,279	$ 844,589

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 June 30					
Balance March 31, 2021	$ (59,703)		$ (1,809)		$ (61,512)
OCI (loss) before reclassifications	(1,125)		870		(255)
Amounts reclassified from accumulated other comprehensive loss	1,189	(a)	—		1,189
Balance June 30, 2021	$ (59,639)		$ (939)		$ (60,578)
Balance March 31, 2020	$ (55,317)		$ (262)		$ (55,579)
OCI (loss) before reclassifications	(2,008)		(1,549)		(3,557)
Amounts reclassified from accumulated other comprehensive loss	999	(a)	262	(b)	1,261
Balance June 30, 2020	$ (56,326)		$ (1,549)		$ (57,875)

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Six Months Ended June 30					
Balance December 31, 2020	$ (60,725)		$ (2,071)		$ (62,796)
OCI (loss) before reclassifications	(1,125)		1,132		7
Amounts reclassified from accumulated other comprehensive loss	2,211	(a)	—		2,211
Balance June 30, 2021	$ (59,639)		$ (939)		$ (60,578)
Balance December 31, 2019	$ (56,522)		$ (574)		$ (57,096)
OCI (loss) before reclassifications	(2,008)		(1,257)		(3,265)
Amounts reclassified from accumulated other comprehensive loss	2,204	(a)	282	(b)	2,486
Balance June 30, 2020	$ (56,326)		$ (1,549)		$ (57,875)

(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		Derivative Instruments		Total
Three Months Ended June 30					
Balance March 31, 2021	$ (39,991)		$ —		$ (39,991)
OCI (loss) before reclassifications	(914)		—		(914)
Amounts reclassified from accumulated other comprehensive loss	1,073	(a)	—		1,073
Balance June 30, 2021	$ (39,832)		$ —		$ (39,832)
Balance March 31, 2020	$ (33,935)		$ (262)		$ (34,197)
OCI (loss) before reclassifications	(1,951)		—		(1,951)
Amounts reclassified from accumulated other comprehensive loss	861	(a)	262	(b)	1,123
Balance June 30, 2020	$ (35,025)		$ —		$ (35,025)

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Six Months Ended June 30					
Balance December 31, 2020	$ (40,918)		$ —		$ (40,918)
OCI (loss) before reclassifications	(914)		—		(914)
Amounts reclassified from accumulated other comprehensive loss	2,000	(a)	—		2,000
Balance June 30, 2021	$ (39,832)		$ —		$ (39,832)
Balance December 31, 2019	$ (34,948)		$ (574)		$ (35,522)
OCI (loss) before reclassifications	(1,951)		292		(1,659)
Amounts reclassified from accumulated other comprehensive loss	1,874	(a)	282	(b)	2,156
Balance June 30, 2020	$ (35,025)		$ —		$ (35,025)

(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.

14. Income Taxes

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

Federal income tax laws require the amortization of a majority of the balance over the remaining regulatory life of the related property. As a result of the modifications made to the annual transmission formula rate during the second quarter of 2018, the Company began amortization of FERC jurisdictional net excess deferred tax liabilities in 2018. On March 13, 2019, the ACC approved the Company's proposal to amortize non-depreciation related net excess deferred tax liabilities subject to its jurisdiction over a twelve-month period. As a result, the Company began amortization in March 2019. The Company recorded $14 million of income tax benefit related to the amortization of these non-depreciation related net excess deferred tax liabilities as of March 31, 2020, with these non-depreciation related net excess deferred tax liabilities being fully amortized as of March 31, 2020. On October 29, 2019, the ACC approved the Company's proposal to amortize depreciation related net excess deferred tax liabilities subject to its jurisdiction over a 28.5-year period with amortization to retroactively begin as of January 1, 2018. The Company recorded $14 million of income tax benefit related to amortization of these depreciation related net excess deferred tax liabilities for the periods ending June 30, 2021 and June 30, 2020. See Note 4 for more details.

Net income associated with the Palo Verde sale leaseback VIEs is not subject to tax. As a result, there is no income tax expense associated with the VIEs recorded on the Pinnacle West Consolidated and APS Consolidated Statements of Income. See Note 6 for additional details related to the Palo Verde sale leaseback VIEs.

As of the balance sheet date, the tax year ended December 31, 2017 and all subsequent tax years remain subject to examination by the IRS. With a few exceptions, the Company is no longer subject to state income tax examinations by tax authorities for years before 2016.

15. Leases

We lease certain land, buildings, vehicles, equipment and other property through operating rental agreements with varying terms, provisions, and expiration dates. APS also has certain purchased power agreements that qualify as lease arrangements. Our leases have remaining terms that expire in 2021 through 2050. Substantially all of our leasing activities relate to APS.

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. These lessor trust entities have been deemed VIEs for which APS is the primary beneficiary. As the primary beneficiary, APS consolidated these lessor trust entities. The impacts of these sale leaseback transactions are excluded from our lease disclosures as lease accounting is eliminated upon consolidation. See Note 6 for a discussion of VIEs.

On May 1, 2021, APS had a new purchased power lease contract that commenced. The lease term ends on October 31, 2027. This lease allows APS the right to the generation capacity from a natural-gas fueled generator during the months of May through October over the contract term. APS does not operate or maintain the leased asset. APS controls the dispatch of the leased asset during the months of May through October and is required to pay a fixed monthly capacity payment during these periods of use. For these types of leased assets APS has elected to combine both the lease and non-lease payment components and accounts for the entire fixed payment as a lease obligation. This purchased power lease contract is accounted for as an operating lease. The contract does not contain a purchase option or a term extension option. In addition to the fixed monthly capacity payment, APS must also pay variable charges based on the actual production volume of the asset. The variable consideration is not included in the measurement of our lease obligation.

The following tables provide information related to our lease costs (dollars in thousands):

	Three Months Ended June 30, 2021			**Three Months Ended June 30, 2020**		
	Purchased Power Lease Contracts	Land, Property & Equipment Leases	Total	Purchased Power Lease Contracts	Land, Property & Equipment Leases	Total
Operating lease cost	$ 29,514	$ 4,598	$ 34,112	$ 17,221	$ 4,651	$ 21,872
Variable lease cost	40,539	256	40,795	40,821	255	41,076
Short-term lease cost	—	1,260	1,260	—	996	996
Total lease cost	$ 70,053	$ 6,114	$ 76,167	$ 58,042	$ 5,902	$ 63,944

	Six Months Ended June 30, 2021			**Six Months Ended June 30, 2020**		
	Purchased Power Lease Contracts	Land, Property & Equipment Leases	Total	Purchased Power Lease Contracts	Land, Property & Equipment Leases	Total
Operating lease cost	$ 29,514	$ 9,239	$ 38,753	$ 17,221	$ 9,304	$ 26,525
Variable lease cost	62,027	510	62,537	61,394	498	61,892
Short-term lease cost	—	2,249	2,249	—	1,786	1,786
Total lease cost	$ 91,541	$ 11,998	$ 103,539	$ 78,615	$ 11,588	$ 90,203

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

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

	June 30, 2021		
Year	Purchased Power Lease Contracts	Land, Property & Equipment Leases	Total
2021 (remaining six months of 2021)	$ 95,596	$ 7,762	$ 103,358
2022	103,744	11,872	115,616
2023	106,161	9,544	115,705
2024	108,634	6,955	115,589
2025	111,166	5,181	116,347
2026	75,099	3,989	79,088
Thereafter	39,106	34,444	73,550
Total lease commitments	639,506	79,747	719,253
Less imputed interest	25,803	17,613	43,416
Total lease liabilities	$ 613,703	$ 62,134	$ 675,837

We recognize lease assets and liabilities upon lease commencement. At June 30, 2021, we have lease arrangements that have been executed, but have not yet commenced. These arrangements primarily relate to energy storage agreements, with lease commencement dates expected to begin in June 2022 with terms ending through December 2042. We expect the total fixed consideration paid for these arrangements, which includes both lease and nonlease payments, will approximate $392 million over the term of the arrangements.

The following tables provide other additional information related to operating lease liabilities (dollars in thousands):

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Cash paid for amounts included in the measurement of lease liabilities — operating cash flows:	$ 13,068	$ 7,624
Right-of-use operating lease assets obtained in exchange for operating lease liabilities	248,694	434,997

	June 30, 2021	December 31, 2020
Weighted average remaining lease term	6 years	6 years
Weighted average discount rate (a)	1.72 %	1.69 %

(a) Most of our lease agreements do not contain an implicit rate that is readily determinable. For these agreements we use our incremental borrowing rate to measure the present value of lease liabilities. We determine our incremental borrowing rate at lease commencement based on the rate of interest that we would have to pay to borrow, on a collateralized basis over a similar term, an amount equal to the lease payments in a similar economic environment. We use the implicit rate when it is readily determinable.

16. Asset Retirement Obligations

During the six months ended June 30, 2021, the Company revised its cost estimates for existing Asset Retirement Obligations (ARO) at Cholla related to updated estimates for the closure of ponds and facilities, which resulted in an increase to the ARO of $11.1 million. (See additional details in Notes 4 and 8.)

The following schedule shows the change in our asset retirement obligations for the six months ended June 30, 2021 (dollars in thousands):

	2021
Asset retirement obligations at January 1, 2021	$ 705,083
Changes attributable to:	
Accretion expense	18,828
Settlements	(2,853)
Estimated cash flow revisions	10,932
Asset retirement obligations at June 30, 2021	$ 731,990

In accordance with regulatory accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal. See detail of regulatory liabilities in Note 4.

17. New Accounting Standard

ASU 2021-05, Leases: Certain Leases with Variable Lease Payments

In July 2021, a new accounting standard was issued that amends the lease accounting guidance. The amended guidance will require lessors to account for certain lease transactions, that contain variable lease payments, as operating leases. The amendments are intended to eliminate the recognition of any day-one loss associated with certain sales-type and direct-financing lease transactions. The changes do not impact lessee accounting. The new guidance is effective for us on January 1, 2022 and may be adopted using either a retrospective or prospective approach. As we typically are not the lessor in these type of lease transactions, we do not expect the adoption of this guidance will have a material impact on our financial statements.

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 2020 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 $21 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

The COVID-19 pandemic continues to be an evolving situation. The Company is operating under long-standing pandemic and business continuity plans that exist to address situations including pandemics like COVID-19. We are focused on ensuring the health and safety of our employees, contractors and the general public by helping limit the spread of this virus and ensuring continued, safe and reliable electric service for APS customers.

We identified business-critical positions in our operations and support organizations, with backup personnel ready to assist if an issue arose. Additionally, efforts to ensure the health and safety of our employees resulted in bifurcated control rooms, thus reducing the number of employees in mission-critical locations. We also established COVID-19 safety protocols, social distancing practices and offering virtual options whenever possible. The Company also took rapid action to implement an all Company COVID-19 hotline, a focused COVID-19 team, and procured on-site COVID-19 testing at key facilities early in the pandemic. Through this testing, case management and contact tracing, the Company has been able to significantly limit COVID-19 transmission in the workplace. As a result of these efforts, we were able to maintain the continuity of the essential services that we provide to our customers, while also managing the spread of the virus and promoting the health, physical and mental well-being and safety of our employees, customers and communities. In the summer of 2021, the Company began transitioning employees that were previously working remotely back to the workplace on a limited basis and began the reduction of our COVID-19 safety protocols and restrictions.

Essential planned work and capital investments are continuing during the pandemic with priority to support fire mitigation and summer storm efforts, as well as heat related outages. APS has measures in place to continue to monitor resource needs and supply chain adequacy. At this time, APS does not believe it has any material supply chain risks due to COVID-19 that would impact its ability to serve customers' needs.

The Company's operations and maintenance expenses, exclusive of bad debt expense, increased by approximately $3.4 million for the period ended June 30, 2021 due to costs for personal protective equipment and other health and safety-related costs related to COVID-19. We expect the Company's operation and maintenance expenses will continue to be impacted for 2021 by the need for additional personal protective equipment and other health and safety-related costs related to COVID-19.

While the total expected impact of COVID-19 on future sales is currently unknown, APS experienced higher electric residential sales and lower electric commercial and industrial sales from the outset of the pandemic through April 2021. Beginning in May 2021, electric sales to commercial and industrial customers increased to levels in line with pre-COVID sales. APS cannot predict whether sales from commercial and industrial customers has fully recovered, but it expects sales trends to continue normalizing during 2021 as business activity continues to recover and more people return to work. Based on past experience, a 1% variation in our annual kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $20 million.

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

On June 30, 2020, FERC issued an order granting a waiver request related to the existing AFUDC rate calculation beginning March 1, 2020 through February 28, 2021. On February 23, 2021, this waiver was extended until September 30, 2021. The order provides 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 has 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 has left all other aspects of the AFUDC formula composite rate calculation unchanged. This change impacts the AFUDC composite rate in both 2020 and 2021, but does not impact prior years. Furthermore, the change in the composite rate calculation does not impact our accounting treatment for these costs. The change did not have a material impact on our financial statements. See Note 1.

Due to the COVID-19 pandemic, APS voluntarily suspended disconnections of customers for nonpayment and waived late payment fees beginning March 13, 2020 until December 31, 2020. The suspension of disconnection of customers for nonpayment ended on January 1, 2021 and customers were automatically placed on eight-month payment arrangements if they had past due balances at the end of the disconnection period of $75 or greater. APS will continue to waive late payment fees until October 15, 2021. APS has experienced and is continuing to experience an increase in bad debt expense associated with the COVID-19 pandemic, the Summer Disconnection Moratorium and the related write-offs of customer delinquent accounts. APS currently estimates that the Summer Disconnection Moratorium, the suspension of disconnections during the COVID-19 pandemic and the increased bad debt expense associated with this will result in a negative impact to its 2021 operating results of approximately $20 million to $30 million pre-tax above the impact of disconnections on its operating results for years that did not have the Summer Disconnection Moratorium or COVID-19 pandemic. These estimated impact amounts for 2021 depend on certain current assumptions, including, but not limited to, customer behaviors, population and employment growth, and the impacts of COVID-19 on the economy. See Note 4.

In February 2021, due to COVID-19, APS delayed the annual reset of the PSA. Rather than the increase being effective February 2021, the PSA reset will be implemented with 50% of the increase effective April 2021 and the remaining 50% increase effective November 2021. See Note 4.

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

Strategic Overview

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

Clean Energy Commitment

We are committed to doing our part to make the future clean and carbon-free. Our vision for APS and Arizona presents an opportunity to engage with customers, communities, employees, policymakers, shareholders and others to achieve a shared, sustainable vision for Arizona. This 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 new 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. Our 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 provides 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 supports the Navajo Nation, where the Four Corners Power Plant is located, the communities surrounding the Cholla Power Plant and the Hopi Tribe, which is impacted by closure of the Navajo Plant. The CCT plan is currently pending ACC approval. See Note 4 for a discussion of the CCT plan.

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 approvals. Under seasonal operation, a single unit will remain on-line 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 intends to strengthen its already diverse energy mix by increasing its investments in carbon-free resources. Its near-term actions include competitive solicitations to procure clean energy resources such as solar, wind, energy storage, demand response and DSM resources, all of which lead to a cleaner grid.

APS has a diverse portfolio of existing and planned renewable resources, including solar, wind, geothermal, biomass and biogas. APS's clean energy strategy includes executing purchased power contracts for new facilities, ongoing development of distributed energy resources and procurement of new facilities to be owned by APS.

In September 2019, APS issued a 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 power purchase agreement for a wind resource that is expected to be in service in the fourth quarter of 2021. Also in September 2019, APS issued a RFP that sought competitive proposals for up to 150 MW of APS-owned solar resources, designed with the flexibility to add energy storage as a future option. Negotiations pursuant to this RFP were terminated in March 2021. 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 solicits both standalone energy storage and renewable energy plus energy storage resources and additional peaking capacity resources (collectively, the "December 2020 RFPs"). In April 2021, the all source RFP portion of the December 2020 RFPs was expanded to seek proposals for the development of a solar generating resource to be owned by APS and sited on APS land. Such resources are expected to be in service during 2023 and 2024.

The following table summarizes the resources in APS's renewable energy portfolio that are in operation and under development as of June 30, 2021. 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	247	—
Purchased Power Agreements Renewables:		
Solar	310	160
Wind (a)	289	110
Geothermal	10	—
Biomass	14	—
Biogas	3	—
Total Purchased Power Agreements	626	270
Total Distributed Energy: Solar (b)	1,162	52 (c)
Total Renewable Portfolio	2,035	322

(a) Includes 90 MW wind power purchase agreement that is currently in operation that will be decommissioned in 2021 and rebuilt in the same year, together with an additional 110 MW, for a total of 200 MW, as a result of a power purchase agreement executed in September 2020.
(b) Includes rooftop solar facilities owned by third parties. Distributed generation is produced in Direct Current and is converted to Alternating Current for reporting purposes.
(c) 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. Storage can provide capacity, improve power quality, be utilized for system regulation, integrate renewable generation and, in certain circumstances, be used to defer certain traditional infrastructure investments. Energy storage can also aid in integrating higher levels of renewables by storing excess energy when system demand is low and renewable production is high and then releasing the stored energy during peak demand hours later in the day and after sunset. APS is utilizing grid-scale energy storage projects to benefit customers, to increase renewable utilization, and to further our understanding of how storage works with other advanced technologies and the grid. We are preparing for additional energy storage in the future.

In early 2018, APS entered into a 15-year power purchase agreement for a 65 MW solar facility that charges a 50 MW solar-fueled battery. Service under the agreement was scheduled to begin in 2021; however, APS terminated the agreement, effective February 16, 2021, because project development could not be sufficiently advanced to support the expected in-service date. 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 by June 2022. On August 2, 2021, APS executed a contract for an additional 60 megawatts 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 all of APS's current APS-owned utility-scale solar facilities.

Additionally, in February 2019, APS signed two 20-year PPAs for energy storage totaling 150 MW. In April 2019, a battery module in APS's McMicken battery energy storage facility experienced an equipment failure, which prompted an internal investigation to determine the cause. APS completed its investigation of the McMicken battery incident and is working with all counterparties to ensure that the learnings from the investigation, and the corresponding safety requirements, are incorporated into all battery storage projects going forward, including the projects associated with the two above-referenced PPAs. These PPAs were also 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 both agreements is expected to begin in 2022.

APS currently plans to install at least 850 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. Currently, APS is seeking energy storage resources through the December 2020 RFPs. Such resources are expected to be in service during 2023 and 2024.

The following table summarizes the resources in APS's energy storage portfolio that are in operation and under development as of June 30, 2021. Agreements for the development and completion of future resources are subject to various conditions.

	Net Capacity in Operation (MW)	**Net Capacity Planned / Under Development (MW)**
APS Owned: Energy Storage	—	201
Purchase Power Agreements Energy Storage	—	150
Residential Energy Storage (a)	9	—
Total Energy Storage Portfolio	**9**	**351**

(a) This includes 9 MW of APS customer owned batteries and 0.3 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 June 2021, the average residential bill decreased by 6.7%, or $10.01, 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. Through the initiative and existing cost management practices, in 2020, APS met its goal of $20 million in cost savings. In 2021, APS continues to drive this initiative to identify opportunities to streamline its business processes and deliver sustainable cost savings.

Participation in the EIM continues to be an effective 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 visibility and 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 in discussions with the EIM operator, California Independent

System Operator, Inc. ("CAISO"), and other EIM participants about the feasibility of creating a voluntary day-ahead market to achieve more cost savings and use the region's renewable resources more efficiently.

Reliable

While our energy mix evolves, the obligation to deliver reliable service to our customers remains. Notwithstanding the challenges presented by the COVID-19 pandemic as well as the hottest summer on record, APS continued to provide reliable service to its customers in 2020, setting a new all-time high peak energy demand of 7,660 MW, exceeding the prior peak set in 2017 by nearly 300 MW and achieved strong reliability results.

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, 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. APS formally opposed those changes in front of FERC. 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. However, APS cannot predict the outcome of these proceedings. Nor can PNW or APS predict whether energy shortages, market priorities, and/or price spikes due to extreme weather conditions will have an impact on its financial position, results of operations or cash flows.

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

Customers are at the core of what APS does every day and its focus remains on its customers and the communities it serves. It is APS's goal to achieve an industry-leading best-in-class customer experience, including that APS improve its J.D. Power ("JDP") customer satisfaction ratings to the first quartile nationally. APS's focus on customer experience has resulted in a measurable increase in its customer satisfaction. Its mid-year 2021 JDP customer satisfaction score represents APS's highest overall satisfaction score on record and continued incremental improvement from 2020 year-end scores, which were among the most improved nationally.

APS also convened a customer advisory board and stakeholder committee in 2020 to serve as a vehicle for gathering valuable qualitative insights, directly from customers and stakeholders, that intends to keep APS apprised of customer needs, wants, and perspectives. Additionally, the customer advisory board is leveraged to identify and diagnose potential customer pain points and to help shape and co-create customer solutions. The customer advisory board has met several times in 2021, addressing rate plan simplification, bill redesign and customer construction communications, among other things.

APS is also focused on educating customers on rate plans through monthly bill analysis and communicating to customers their most economical plan. APS continues to see an increase in rate plan digital engagement, rate plan changes and rate comparison volumes on its website. As of June 30, 2021, 53.3% of its customers are on their most economical plan (as determined based on the time of the calculation).

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 July 1, 2021, APS has installed 256 dual-plug Level 2 charging stations at business customer locations with more stations expected to be added through 2022. The program provides charging equipment, installation, and maintenance to business customers, government agencies, and multifamily housing communities. In addition to the Level 2 charging stations, APS will begin construction of direct current fast charging stations that will be owned and operated by APS at five locations in Arizona. This project is projected to be completed during 2022, with each location including 2-150 kilowatt and 2-350 kilowatt DC fast charging stations. Charging at these stations will be accessible through the Electrify America charging network.

Additionally, as part of the 2020 DSM Plan, the ACC approved programs for electric vehicles, including a residential program to measure electric vehicle charging as well as 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 is actively participating in this process, which was submitted in April 2021 to the ACC for review and approval. The ACC will be holding workshops in August 2021 to discuss the TE Plan.

Hydrogen Production

Palo Verde, in partnership with Idaho National Laboratory ("INL") and Energy Harbor Corporation and Xcel Energy Incorporated, has been chosen by the DOE's Office of Nuclear Energy to participate in a hydrogen production project with the goal to improve the long-term economic competitiveness of the nuclear power industry. The multi-phase project is planned for 2020 through 2023. In the first phase, INL performed a technical and economic assessment of using electricity generated at Palo Verde to produce hydrogen.

Based on the experience from Palo Verde's utility partners' demonstration projects and from the Palo Verde-specific technical and economic assessment performed by INL, PNW Hydrogen LLC, a subsidiary of Pinnacle West, recently submitted a request for funding to the DOE's Office of Nuclear Energy to support moving forward with a hydrogen production pilot.

Carbon Capture

Carbon capture technologies can isolate CO2 and either sequester it permanently in geologic formations or convert it for use in products. Currently, almost all existing fossil fuel generators do not control carbon emissions the way they control emissions of other air pollutants such as sulfur dioxide or oxides of nitrogen. Carbon capture technologies are still in the demonstration phase and while they show promise, they are still being tested in real-world conditions. These technologies could offer the potential to keep in operation existing generators that otherwise would need to be retired. APS will continue to monitor this emerging technology.

Regulatory Overview

On October 31, 2019, APS filed an application with the ACC 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 is currently the subject of a separate proceeding (see "SCR Cost Recovery" in Note 4). It also reflects a net credit to base rates of approximately $115 million primarily due to the prospective inclusion of rate refunds currently provided through the TEAM. The proposed total 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 twelve months ended June 30, 2019, adjusted as described below;
- an original cost rate base of $8.87 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	45.3 %	4.1 %
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 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 in this rate case. The ACC Staff recommends, among other things, a (i) $89.7 million revenue increase, (ii) average annual customer bill increase of 2.7%, (iii) 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) recovery of the deferral and rate base effects of the construction and operating costs of the Four Corners SCR project and (vi) recovery of the rate base effects of the construction and ongoing consideration of the deferral of the Ocotillo modernization project. RUCO recommends, among other things, a (i) $20.8 million revenue decrease, (ii) average annual customer bill decrease of 0.63%, (iii) return on equity of 8.74%, (iv) a 0% return on the increment of fair value rate base, (v) 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) 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) 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 Power Plant 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 Generating Station, which would primarily be funded by customers.

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 schedule concluded on April 30, 2021. In May 2021, the ACC declined to re-open the evidentiary record in APS's pending rate case to take additional evidence on topics raised by certain ACC Commissioners, including adjustor cost recovery mechanisms.

On August 2, 2021, the Administrative Law Judge issued a Recommended Opinion and Order in APS's rate case (the "2019 Rate Case ROO"). The 2019 Rate Case ROO recommends, among other things, a (i) $111 million base revenue decrease, (ii) return on equity for original cost rate base of 9.16%, (iii) a 0.15% 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 0.10% reduction to return on equity resulting in an effective fair value return of 0.05%, (iv) 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" in Note 4 for additional information), (v) 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 and (vi) a 15% disallowance of annual amortization of Navajo Plant regulatory asset recovery. 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 Generating Station. These amounts would be recoverable from APS's customers through the RES. APS expects to file an exception regarding the disallowance of the SCR cost deferrals and plant investments that was recommended in the 2019 Rate Case ROO and APS is continuing to evaluate any additional exceptions it may file. The 2019 Rate Case ROO will be discussed at an upcoming ACC open meeting. APS cannot predict the outcome of this proceeding.

See Note 4 for information regarding additional regulatory matters.

Arizona Attorney General Matter

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, $24 million of which is being 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.

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.

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

El Dorado. El Dorado is a wholly-owned subsidiary of Pinnacle West. El Dorado owns debt investments and minority interests in several energy-related investments and Arizona community-based ventures. 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. 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. The investment will be made by El Dorado as investments are selected by the invisionAZ Fund.

Key Financial Drivers

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

Electric Operating Revenues. For the years 2018 through 2020, retail electric revenues comprised approximately 95% of our total operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, distributed energy additions, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery mechanisms. These revenue transactions are affected by the availability of excess generation or other energy resources and wholesale market conditions, including competition, demand and prices.

Actual and Projected Customer and Sales Growth. Retail customers in APS's service territory increased 2.2% for the six-month period ended June 30, 2021 compared with the prior-year period. For the three years 2018 through 2020, APS's customer growth averaged 2.0% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2021 and for 2021 through 2023 based on our assessment of steady population growth in Arizona.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 3.3% for the six-month period ended June 30, 2021 compared with the prior-year period. While steady customer growth was offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives, the main drivers of positive sales for this period were continued strong residential sales due to 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 is currently unknown, APS experienced higher electric residential sales and lower electric commercial and industrial sales from the outset of the pandemic through April 2021. Beginning in May 2021, electric sales to commercial and industrial customers increased to levels in line with pre-COVID sales. APS cannot predict whether sales from commercial and industrial customers has fully recovered, but it expects sales trends to continue normalizing during 2021 as business activity continues to recover and more people return to work.

For the three years 2018 through 2020, annual retail electricity sales were about flat, adjusted to exclude the effects of weather variations. We currently project that annual retail electricity sales in kWh will increase in the range of 1.0% to 2.0% for 2021 and for 2021 through 2023, including the effects of customer conservation, energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations and excluding the impacts of several new, large manufacturing facilities opening operations in Metro Phoenix. The impact of the new, large manufacturing facilities is likely to increase the expected annual sales growth rate as early as 2022, but demand from these customers remains uncertain at this point. 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 slower than expected growth of the Arizona economy, slower than expected ramp-up of the new data centers, or acceleration of the expected effects of customer conservation, energy efficiency, 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 distributed generation, and responses to retail price changes. Based on past experience, a 1% variation in our annual kWh sales projections attributable to such economic factors under normal business conditions can result in increases or decreases in annual net income of approximately $20 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 10.8% of the assessed value for 2020, 10.9% for 2019 and 11.0% for 2018. 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. On December 22, 2017, the Tax Act was enacted and was generally effective on January 1, 2018. Changes impacting the Company include a reduction in the corporate tax rate to 21%, revisions to the rules related to tax bonus depreciation, limitations on interest deductibility and an associated exception for certain public utilities, and requirements that certain excess deferred tax amounts of regulated utilities be normalized. See Note 14 for details of the impacts on the Company as of June 30, 2021. In APS's 2017 rate case decision, the ACC approved a Tax Expense Adjustor Mechanism which will be used to pass through the income tax effects to retail customers of the Tax Act. (See Note 4 for details of the TEAM.)

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 June 30, 2021 compared with three-month period ended June 30, 2020.

Our consolidated net income attributable to common shareholders for the three months ended June 30, 2021 was $216 million, compared with consolidated net income attributable to common shareholders of $194 million for the prior-year period. The results reflect an increase of approximately $25 million for the regulated electricity segment primarily due to higher revenue driven by customer usage and growth and the effects of weather, and higher pension and other postretirement non-service credits, partially offset by higher operations and maintenance expense, higher depreciation expense and higher income taxes, including lower amortization of excess deferred taxes.

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

	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 726	$ 690	$ 36
Operations and maintenance	(228)	(218)	(10)
Depreciation and amortization	(158)	(152)	(6)
Taxes other than income taxes	(60)	(57)	(3)
Pension and other postretirement non-service credits - net	28	14	14
All other income and expenses, net	18	19	(1)
Interest charges, net of allowance for borrowed funds used during construction	(58)	(58)	—
Income taxes	(47)	(41)	(6)
Less income related to noncontrolling interests (Note 6)	(4)	(5)	1
Regulated electricity segment income	217	192	25
All other	(1)	2	(3)
Net Income Attributable to Common Shareholders	$ 216	$ 194	$ 22

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $36 million higher for the three months ended June 30, 2021 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)		
Higher retail revenue due to customer growth and changes in customer usage patterns, partially offset by the impacts of energy efficiency and distributed generation	$ 39	$ 12	$ 27
Effects of weather	9	3	6
Higher renewable energy regulatory surcharges, partially offset by operations and maintenance costs	2	(1)	3
Higher transmission revenues (Note 4)	1	—	1
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	19	20	(1)
Miscellaneous items, net	(2)	(2)	—
Total	$ 68	$ 32	$ 36

Operations and maintenance. Operations and maintenance expenses increased $10 million for the three months ended June 30, 2021 compared with the prior-year period primarily because of:

- An increase of $12 million related to employee benefits;
- An increase of $4 million primarily related to a decreased recovery from contributions of administrative and general costs from Palo Verde owners;
- An increase of $3 million primarily related to costs for renewable energy and similar regulatory programs, which are partially offset in operating revenues and purchased power;
- A decrease of $6 million primarily related to customer support funds, personal protective equipment and other health and safety-related costs for COVID-19 response;
- A decrease of $5 million for costs related to transmission and distribution; and
- An increase of $2 million for corporate resources and other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $6 million higher for the three months ended June 30, 2021 compared to the prior-year period primarily due to increased plant in service of $7 million, partially offset by the regulatory deferrals for the Ocotillo modernization project and the Four Corners SCR project of $1 million.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $14 million higher for the three months ended June 30, 2021 compared to the prior-year period primarily due to actual market returns exceeding estimated returns in 2020.

Income taxes. Income taxes were $6 million higher for the three months ended June 30, 2021 compared with the prior-year period primarily due to higher pre-tax income.

Operating Results — Six-month period ended June 30, 2021 compared with six-month period ended June 30, 2020.

Our consolidated net income attributable to common shareholders for the six months ended June 30, 2021 was $251 million, compared with consolidated net income attributable to common shareholders of $224 million for the prior-year period. The results reflect an increase of approximately $32 million for the regulated electricity segment, primarily due to higher revenue driven by higher customer growth and usage, lower refunds in the current year related to the Tax Act, the effects of weather and higher transmission revenue, and higher pension and other postretirement non-service credits, partially offset by higher income taxes, including lower amortization of excess deferred taxes, higher operations and maintenance expense and higher depreciation expense.

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

	Six Months Ended June 30,		
	2021	2020	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 1,222	$ 1,162	$ 60
Operations and maintenance	(458)	(439)	(19)
Depreciation and amortization	(317)	(307)	(10)
Taxes other than income taxes	(118)	(113)	(5)
Pension and other postretirement non-service credits - net	56	28	28
All other income and expenses, net	33	34	(1)
Interest charges, net of allowance for borrowed funds used during construction	(114)	(113)	(1)
Income taxes	(42)	(21)	(21)
Less income related to noncontrolling interests (Note 6)	(9)	(10)	1
Regulated electricity segment income	253	221	32
All other	(2)	3	(5)
Net Income Attributable to Common Shareholders	$ 251	$ 224	$ 27

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $60 million higher for the six months ended June 30, 2021 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)		
Higher retail revenue due to customer growth and changes in customer usage patterns, partially offset by the impacts of energy efficiency and distributed generation	$ 40	$ 13	$ 27
Lower refunds in the current year related to the Tax Act (Note 4)	17	—	17
Effects of weather	14	4	10
Higher transmission revenues (Note 4)	5	—	5
Higher renewable energy regulatory surcharges, partially offset by operations and maintenance costs	3	(1)	4
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	25	27	(2)
Miscellaneous items, net	(3)	(2)	(1)
Total	$ 101	$ 41	$ 60

Operations and maintenance. Operations and maintenance expenses increased $19 million for the six months ended June 30, 2021 compared with the prior-year period primarily because of:

- An increase of $19 million related to employee benefits;
- An increase of $9 million in fossil generation costs primarily due to higher planned outages and higher operating costs;
- An increase of $3 million primarily related to costs for renewable energy and similar regulatory programs, which are partially offset in operating revenues and purchased power;
- A decrease of $5 million primarily related to customer support funds, personal protective equipment and other health and safety-related costs for COVID-19 response; and
- A decrease of $7 million for corporate resources and other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $10 million higher for the six months ended June 30, 2021 compared to the prior-year period primarily due to increased plant in service of $13 million, partially offset by the regulatory deferrals for the Ocotillo modernization project and the Four Corners SCR project of $3 million.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $28 million higher for the six months ended June 30, 2021 compared to the prior-year period primarily due to actual market returns exceeding estimated returns in 2020.

Income taxes. Income taxes were $21 million higher for the six months ended June 30, 2021 compared with the prior-year period primarily due to lower amortization of excess deferred taxes and higher pre-tax income, partially offset by a net operating loss carryback benefit that the Company recognized during the first quarter of 2021.

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 June 30, 2021, APS's common equity ratio, as defined, was 51%. Its total shareholder equity was approximately $6.3 billion, and total capitalization was approximately $12.3 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $4.9 billion, assuming APS's total capitalization remains the same. This restriction does not materially affect Pinnacle West's ability to meet its ongoing cash needs or ability to pay dividends to shareholders.

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

Our consolidated change in cash and cash equivalents for the period ended June 30, 2021 compared to December 31, 2020 was a decrease of $46 million. The change is primarily driven by cash used for capital expenditures, fuel and purchased power and operations and maintenance cost, which is partially offset by higher cash receipts of electric revenues, increased short-term debt borrowings and lower long-term debt repayments. The following tables present net cash provided by (used for) operating, investing and financing activities (dollars in millions):

Pinnacle West Consolidated

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020	Net Change
Net cash flow provided by operating activities	$ 313	$ 370	$ (57)
Net cash flow used for investing activities	(650)	(653)	3
Net cash flow provided by financing activities	291	280	11
Net change in cash and cash equivalents	$ (46)	$ (3)	$ (43)

Arizona Public Service Company

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020	Net Change
Net cash flow provided by operating activities	$ 315	$ 378	$ (63)
Net cash flow used for investing activities	(657)	(656)	(1)
Net cash flow provided by financing activities	297	274	23
Net change in cash and cash equivalents	$ (45)	$ (4)	$ (41)

Operating Cash Flows

Six-month period ended June 30, 2021 compared with six-month period ended June 30, 2020. Pinnacle West's consolidated net cash provided by operating activities was $313 million in 2021, compared to $370 million in 2020, a decrease of $57 million in net cash provided by operating activities primarily due to $109 million higher fuel and purchased power costs and $10 million higher payments for operations and maintenance cost, partially offset by $18 million higher cash receipts from electric revenues and $45 million other changes in working capital.

Retirement plans and other postretirement benefits. Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. 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 124% funded as of January 1, 2021 and 117% as of January 1, 2020. Under GAAP, the qualified pension plan was 104% funded as of January 1, 2021 and 97% funded as of January 1, 2020. See Note 5 for additional details. The assets in the plan are comprised of fixed-income, equity, real estate, and short-term investments. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We have not made voluntary contributions to our pension plan in 2021. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to $100 million in 2021 and zero in 2022 and 2023. We do not expect to make any contributions over this period to our other postretirement benefit plans. We continue to monitor COVID-19 and its impact on our retirement plans and other postretirement benefits but we believe, due to our liability driven investment strategy, which helps to minimize the impact of market volatility on our plan's funded status, our pension plan's funded status, as measured for GAAP purposes, is still above 95% funded as of June 30, 2021.

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

Investing Cash Flows

Six-month period ended June 30, 2021 compared with six-month period ended June 30, 2020. Pinnacle West's consolidated net cash used for investing activities was $650 million in 2021, compared to $653 million in 2020, a decrease of $3 million primarily related to investing cash activity related to 4CA, partially offset by increased capital expenditures.

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

Capital Expenditures
(dollars in millions)

	Estimated for the Year Ended December 31,		
	2021	**2022**	**2023**
APS			
Generation:			
Clean:			
Nuclear Generation	$ 114	$ 116	$ 125
Renewables and Energy Storage Systems ("ESS") (a)	200	276	281
Other Generation (b)	203	190	187
Distribution	577	556	549
Transmission	185	181	179
Other (c)	221	181	179
Total APS	$ 1,500	$ 1,500	$ 1,500

(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

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 renewable 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

Six-month period ended June 30, 2021 compared with six-month period ended June 30, 2020. Pinnacle West's consolidated net cash provided by financing activities was $291 million in 2021, compared to $280 million in 2020, an increase of $11 million in net cash provided. The increase in net cash provided by financing activities is primarily due to lower long-term debt repayments of $800 million, partially offset by $939 million in lower issuances of long-term debt and a net increase in short-term borrowing of $158 million, partially offset by higher dividend payment of $11 million.

APS's consolidated net cash provided by financing activities was $297 million in 2021, compared to $274 million in 2020, an increase of $23 million in net cash provided. The increase in net cash provided by financing activities is primarily due to lower long-term debt repayments of $350 million, partially offset by $592 million in lower issuances of long-term debt and a net increase in short-term borrowing of $275 million, partially offset by higher dividend payment of $11 million.

Significant Financing Activities. On June 23, 2021, the Pinnacle West Board of Directors declared a dividend of $0.83 per share of common stock, payable on September 1, 2021 to shareholders of record on August 2, 2021.

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.

On May 5, 2020, Pinnacle West refinanced its 364-day $50 million term loan agreement with a new 364-day $31 million term loan agreement that would have matured May 4, 2021. Borrowings under the agreement bore interest at Eurodollar Rate plus 1.40% per annum. Pinnacle West repaid this agreement on April 27, 2021.

On December 23, 2020, Pinnacle West entered into a $150 million term loan facility that matures 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 May 28, 2021, Pinnacle West replaced its $200 million revolving credit facility that would have matured on July 11, 2023, with a new $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 June 30, 2021, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding under the credit facility and $9.7 million of outstanding commercial paper borrowings.

On May 28, 2021, APS replaced its two $500 million revolving credit facilities that would have matured in June 2022 and July 2023, with two new $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 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. 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 June 30, 2021, APS had no outstanding borrowings under its revolving credit facilities, no letters of credit outstanding under the credit facilities and $495 million of outstanding commercial paper borrowings.

See "Financial Assurances" in Note 8 for a discussion of separate outstanding letters of credit and surety bonds.

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 June 30, 2021, the ratio was approximately 55% for Pinnacle West and 50% 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).

Credit Ratings

The ratings of securities of Pinnacle West and APS as of July 29, 2021 are shown below. We are disclosing these credit ratings to enhance understanding of our cost of short-term and long-term capital and our ability to access the markets for liquidity and long-term debt. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS's securities and/or result in an increase in the cost of, or limit access to, capital. Such revisions may also result in substantial additional cash or other collateral requirements related to certain derivative instruments, insurance policies, natural gas transportation, fuel supply, and other energy-related contracts. At this time, we believe we have sufficient available liquidity resources to respond to a downward revision to our credit ratings.

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

Off-Balance Sheet Arrangements

See Note 6 for a discussion of the impacts on our financial statements of consolidating certain VIEs.

Contractual Obligations

As of June 30, 2021, our fuel and purchased power commitments have increased from the information provided in our 2020 Form 10-K. The increase is primarily due to new purchased power and energy storage commitments of approximately $624 million. The majority of the changes relate to 2026 and thereafter.

Other than the item described above, there have been no material changes, as of June 30, 2021, outside the normal course of business in contractual obligations from the information provided in our 2020 Form 10-K. See Note 3 for discussion regarding changes in our short-term and long-term debt obligations. See Note 6 for discussion regarding changes to our contractual obligations related to the Palo Verde sale leaseback transactions.

CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with GAAP, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. There have been no changes to our critical accounting policies since our 2020 Form 10-K. See “Critical Accounting Policies” in Item 7 of the 2020 Form 10-K for further details about our critical accounting policies.

OTHER ACCOUNTING MATTERS

In July 2021, a new accounting standard, ASU 2021-05, was issued that amends lessor’s accounting treatment for certain lease transactions with variable lease payments. The new guidance will be effective for us on January 1, 2022, with no expected material impacts. See Note 17 for additional information related to this new accounting standard.

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):

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Mark-to-market of net positions at beginning of period	$ (13)	$ (71)
Decrease in regulatory asset	122	1
Recognized in OCI:		
Mark-to-market losses realized during the period	—	1
Change in valuation techniques	—	—
Mark-to-market of net positions at end of period	$ 109	$ (69)

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at June 30, 2021 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 2020 Form 10-K and Note 11 for more discussion of our valuation methods.

Source of Fair Value	2021	2022	2023	2024	2025	Total Fair Value
Observable prices provided by other external sources	$ 40	$ 30	$ 10	$ 3	$ —	$ 83
Prices based on unobservable inputs	26	—	—	—	—	26
Total by maturity	$ 66	$ 30	$ 10	$ 3	$ —	$ 109

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):

	June 30, 2021 Gain (Loss)		December 31, 2020 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	$ 6	$ (6)	$ 4	$ (4)
Natural gas	47	(47)	49	(49)
Total	$ 53	$ (53)	$ 53	$ (53)

(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 June 30, 2021. 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 June 30, 2021. 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 June 30, 2021 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 2020 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 2020 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 2020 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.

Item 5. OTHER INFORMATION

In July and August 2021, the Company entered into an amended Key Executive Employment and Severance Agreements ("KEESA") with Ms. Maria Lacal, Executive Vice President and Chief Nuclear Officer of Palo Verde Generating Station, APS, Mr. Theodore Geisler, Senior Vice President and Chief Financial Officer of Pinnacle West and APS, and Mr. Robert E. Smith, Executive Vice President General Counsel and Chief Development Officer of Pinnacle West and APS and other select officers. The KEESA was amended to better align it with current market practice, including adding the following provisions: (i) providing for a Section 280G "net better" cutback provision; and (ii) providing for the severance benefits to also apply in the event of certain involuntary terminations that occur within six months prior to a Change of Control (as defined in the KEESA). The foregoing description of the terms of the KEESA does not purport to be complete, and is qualified in its entirety by reference to the full text thereof, a copy of which is filed as Exhibit 10.4 to this Form 10-Q, and incorporated herein by reference.

Item 6. EXHIBITS

(a) Exhibits

Exhibit No.	Registrant(s)	Description
10.1	Pinnacle West	Amended and Restated Five-Year Credit Agreement dated as of May 28, 2021, among Pinnacle West, as Borrower, Barclays Bank PLC, as Agent, Co-Sustainability Structuring Agent and Issuing Bank, and the lenders and other parties thereto
10.2	Pinnacle West APS	Amended and Restated Five-Year Credit Agreement dated as of May 28, 2021, among APS, as Borrower, Barclays Bank PLC, as Agent, Co-Sustainability Structuring Agent and Issuing Bank, and the lenders and other parties thereto
10.3	Pinnacle West APS	Five-Year Credit Agreement dated as of May 28, 2021, among APS, as Borrower, Barclays Bank PLC, as Agent, Co-Sustainability Structuring Agent and Issuing Bank, and the lenders and other parties thereto
10.4	Pinnacle West APS	Key Executive Employment and Severance Agreement between Pinnacle West and certain executive officers of Pinnacle West and its subsidiaries
10.5	Pinnacle West APS	Four Corners Project Co-Tenancy Agreement, conformed copy up through and including Amendment No. 13, dated June 25, 2021, among APS, Public Service Company of New Mexico, SRP, Tucson Electric Power Company and Navajo Transitional Energy Company, LLC
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: August 5, 2021

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: August 5, 2021

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)