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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2019

OR

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

For the transition period from to

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

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

PINNACLE WEST CAPITAL CORPORATION

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

Emerging growth company ☐

ARIZONA PUBLIC SERVICE COMPANY

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

Emerging growth company ☐

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

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

PINNACLE WEST CAPITAL CORPORATION	Number of shares of common stock, no par value, outstanding as of April 24, 2019: 112,277,359
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of April 24, 2019: 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" 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, 2018 ("2018 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:

- our ability to manage capital expenditures and operations and maintenance costs while maintaining reliability and customer service levels;
- variations in demand for electricity, including those due to weather, seasonality, the general economy, customer and sales growth (or decline), and the effects of energy conservation measures and distributed generation;
- power plant and transmission system performance and outages;
- competition in retail and wholesale power markets;
- regulatory and judicial decisions, developments and proceedings;
- new legislation, ballot initiatives and regulation, including those relating to environmental requirements, regulatory policy, nuclear plant operations and potential deregulation of retail electric markets;
- fuel and water supply availability;
- our ability to achieve timely and adequate rate recovery of our costs, including returns on and of debt and equity capital investment;
- our ability to meet renewable energy and energy efficiency mandates and recover related costs;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- current and future economic conditions in Arizona, including in real estate markets;
- the direct or indirect effect on our facilities or business from cybersecurity threats or intrusions, data security breaches, terrorist attack, physical attack, severe storms, droughts, or other catastrophic events, such as fires, explosions, pandemic health events or similar occurrences;
- the development of new technologies which may affect electric sales or delivery;
- the cost of debt and equity capital and the ability to access capital markets when required;
- environmental, economic and other concerns surrounding coal-fired generation, including regulation of greenhouse gas emissions;
- volatile fuel and purchased power costs;
- the investment performance of the assets of our nuclear decommissioning trust, pension, and other postretirement benefit plans and the resulting impact on future funding requirements;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;
- potential shortfalls in insurance coverage;
- new accounting requirements or new interpretations of existing requirements;
- generation, transmission and distribution facility and system conditions and operating costs;
- the ability to meet the anticipated future need for additional generation and associated transmission facilities in our region;
- the willingness or ability of our counterparties, power plant participants and power plant land owners to meet contractual or other obligations or 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 2018 Form 10-K, in Part II, Item 1A of this report, and in Part I, Item 2 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" of this report, which readers should review carefully before placing any reliance on our financial statements or disclosures. Neither Pinnacle West nor APS assumes any obligation to update these statements, even if our internal estimates change, except as required by law.

PART I — FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

INDEX TO FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

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

	Three Months Ended March 31,	
	2019	2018
OPERATING REVENUES (NOTE 2)	$ 740,530	$ 692,714
OPERATING EXPENSES		
Fuel and purchased power	230,588	197,110
Operations and maintenance	245,634	265,682
Depreciation and amortization	148,707	144,825
Taxes other than income taxes	55,090	53,600
Other expenses	427	163
Total	680,446	661,380
OPERATING INCOME	60,084	31,334
OTHER INCOME (DEDUCTIONS)		
Allowance for equity funds used during construction	11,188	14,079
Pension and other postretirement non-service credits - net	5,114	12,859
Other income (Note 9)	7,169	3,985
Other expense (Note 9)	(4,358)	(3,229)
Total	19,113	27,694
INTEREST EXPENSE		
Interest charges	60,653	58,954
Allowance for borrowed funds used during construction	(6,665)	(6,755)
Total	53,988	52,199
INCOME BEFORE INCOME TAXES	25,209	6,829
INCOME TAXES	2,418	(1,265)
NET INCOME	22,791	8,094
Less: Net income attributable to noncontrolling interests (Note 6)	4,873	4,873
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 17,918	$ 3,221
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	112,337	112,017
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	112,735	112,493
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING		
Net income attributable to common shareholders — basic	$ 0.16	$ 0.03
Net income attributable to common shareholders — diluted	$ 0.16	$ 0.03

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

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

	Three Months Ended March 31,	
	2019	2018
NET INCOME	$ 22,791	$ 8,094
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Derivative instruments:		
Net unrealized loss, net of tax expense of $0 and $96	—	(96)
Reclassification of net realized loss, net of tax benefit of $108 and $82	328	409
Pension and other postretirement benefits activity, net of tax expense of $288 and $443	879	900
Total other comprehensive income	1,207	1,213
COMPREHENSIVE INCOME	23,998	9,307
Less: Comprehensive income attributable to noncontrolling interests	4,873	4,873
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 19,125	$ 4,434

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

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

	March 31, 2019	December 31, 2018
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 6,109	$ 5,766
Customer and other receivables	249,568	267,887
Accrued unbilled revenues	114,077	137,170
Allowance for doubtful accounts	(2,455)	(4,069)
Materials and supplies (at average cost)	280,857	269,065
Fossil fuel (at average cost)	26,294	25,029
Assets from risk management activities (Note 7)	763	1,113
Deferred fuel and purchased power regulatory asset (Note 4)	7,583	37,164
Other regulatory assets (Note 4)	127,642	129,738
Other current assets	65,951	56,128
Total current assets	876,389	924,991
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Notes 11 and 12)	919,309	851,134
Other special use funds (Notes 11 and 12)	238,207	236,101
Other assets	99,446	103,247
Total investments and other assets	1,256,962	1,190,482
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	18,763,499	18,736,628
Accumulated depreciation and amortization	(6,398,512)	(6,366,014)
Net	12,364,987	12,370,614
Construction work in progress	1,233,018	1,170,062
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	104,808	105,775
Intangible assets, net of accumulated amortization	267,998	262,902
Nuclear fuel, net of accumulated amortization	142,610	120,217
Total property, plant and equipment	14,113,421	14,029,570
DEFERRED DEBITS		
Regulatory assets (Note 4)	1,321,507	1,342,941
Operating lease right-of-use assets (Note 16)	193,897	—
Assets for other postretirement benefits (Note 5)	52,674	46,906
Other	39,257	129,312
Total deferred debits	1,607,335	1,519,159
TOTAL ASSETS	$ 17,854,107	$ 17,664,202

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

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

	March 31, 2019	December 31, 2018
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 263,656	$ 277,336
Accrued taxes	199,949	154,819
Accrued interest	50,074	61,107
Common dividends payable	—	82,675
Short-term borrowings (Note 3)	244,050	76,400
Current maturities of long-term debt (Note 3)	250,000	500,000
Customer deposits	87,263	91,174
Liabilities from risk management activities (Note 7)	33,289	35,506
Liabilities for asset retirements	22,823	19,842
Operating lease liabilities (Note 16)	65,435	—
Regulatory liabilities (Note 4)	260,404	165,876
Other current liabilities	114,361	184,229
Total current liabilities	1,591,304	1,648,964
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 3)	4,886,108	4,638,232
DEFERRED CREDITS AND OTHER		
Deferred income taxes	1,811,689	1,807,421
Regulatory liabilities (Note 4)	2,272,082	2,325,976
Liabilities for asset retirements	712,885	706,703
Liabilities for pension benefits (Note 5)	384,492	443,170
Liabilities from risk management activities (Note 7)	14,844	24,531
Customer advances	155,894	137,153
Coal mine reclamation	214,037	212,785
Deferred investment tax credit	200,052	200,405
Unrecognized tax benefits	26,042	22,517
Operating lease liabilities (Note 16)	53,704	—
Other	149,249	147,640
Total deferred credits and other	5,994,970	6,028,301
COMMITMENTS AND CONTINGENCIES (SEE NOTE 8)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 112,340,322 and 112,159,896 issued at respective dates	2,644,063	2,634,265
Treasury stock at cost; 63,271 and 58,135 shares at respective dates	(5,586)	(4,825)
Total common stock	2,638,477	2,629,440
Retained earnings	2,659,086	2,641,183
Accumulated other comprehensive loss	(46,501)	(47,708)
Total shareholders' equity	5,251,062	5,222,915
Noncontrolling interests (Note 6)	130,663	125,790
Total equity	5,381,725	5,348,705
TOTAL LIABILITIES AND EQUITY	$ 17,854,107	$ 17,664,202

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

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

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 22,791	$ 8,094
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	167,801	163,566
Deferred fuel and purchased power	16,709	(18,950)
Deferred fuel and purchased power amortization	12,872	20,002
Allowance for equity funds used during construction	(11,188)	(14,079)
Deferred income taxes	3,620	(229)
Deferred investment tax credit	(353)	(147)
Stock compensation	12,074	10,537
Changes in current assets and liabilities:		
Customer and other receivables	15,476	89,518
Accrued unbilled revenues	23,093	(6,555)
Materials, supplies and fossil fuel	(13,057)	(16,607)
Other current assets	(10,115)	(664)
Accounts payable	26,593	(25,738)
Accrued taxes	45,130	45,984
Other current liabilities	(86,250)	(12,030)
Change in other long-term assets	(65,470)	(3,765)
Change in other long-term liabilities	13,706	(72,065)
Net cash flow provided by operating activities	173,432	166,872
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(259,792)	(361,037)
Contributions in aid of construction	7,938	8,569
Allowance for borrowed funds used during construction	(6,665)	(6,755)
Proceeds from nuclear decommissioning trust sales and other special use funds	179,048	130,456
Investment in nuclear decommissioning trust and other special use funds	(179,618)	(131,027)
Other	4,576	(1,299)
Net cash flow used for investing activities	(254,513)	(361,093)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	497,324	—
Short-term borrowing and payments — net	172,650	263,500
Short-term debt borrowings under revolving credit facility	—	36,000
Short-term debt repayments under revolving credit facility	(5,000)	(25,000)
Dividends paid on common stock	(80,897)	(75,903)
Repayment of long-term debt	(500,000)	—
Common stock equity issuance - net of purchases	(2,653)	(2,828)
Net cash flow provided by financing activities	81,424	195,769
NET INCREASE IN CASH AND CASH EQUIVALENTS	343	1,548
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	5,766	13,892
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 6,109	$ 15,440

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)

	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, January 1, 2018	111,816,170	$ 2,614,805	(64,463)	$ (5,624)	$ 2,442,511	$ (45,002)	$ 129,040	$ 5,135,730
Net income		—		—	3,221	—	4,873	8,094
Other comprehensive income		—		—	—	1,213	—	1,213
Dividends on common stock		—		—	(16)	—	—	(16)
Issuance of common stock	145,793	5,456		—	—	—	—	5,456
Purchase of treasury stock (a)		—	(81,177)	(6,277)	—	—	—	(6,277)
Reissuance of treasury stock for stock-based compensation and other		—	116,543	9,470	—	—	1	9,471
Reclassification of income tax effects related to new tax reform (b)		—		—	8,552	(8,552)	—	—
Balance, March 31, 2018	111,961,963	$ 2,620,261	(29,097)	$ (2,431)	$ 2,454,268	$ (52,341)	$ 133,914	$ 5,153,671
Balance, January 1, 2019	112,159,896	$ 2,634,265	(58,135)	$ (4,825)	$ 2,641,183	$ (47,708)	$ 125,790	$ 5,348,705
Net income		—		—	17,918	—	4,873	22,791
Other comprehensive income		—		—	—	1,207	—	1,207
Dividends on common stock		—		—	(15)	—	—	(15)
Issuance of common stock	180,426	9,798		—	—	—	—	9,798
Purchase of treasury stock (a)		—	(75,791)	(6,882)	—	—	—	(6,882)
Reissuance of treasury stock for stock-based compensation and other		—	70,655	6,121	—	—	—	6,121
Balance, March 31, 2019	112,340,322	$ 2,644,063	(63,271)	$ (5,586)	$ 2,659,086	$ (46,501)	$ 130,663	$ 5,381,725

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

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

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

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

	Three Months Ended March 31,	
	2019	2018
OPERATING REVENUES	$ 740,530	$ 692,006
OPERATING EXPENSES		
Fuel and purchased power	230,588	202,010
Operations and maintenance	240,375	254,601
Depreciation and amortization	148,685	144,112
Taxes other than income taxes	55,078	53,242
Other expenses	427	163
Total	675,153	654,128
OPERATING INCOME	65,377	37,878
OTHER INCOME (DEDUCTIONS)		
Allowance for equity funds used during construction	11,188	14,079
Pension and other postretirement non-service credits - net	5,499	13,197
Other income (Note 9)	6,416	3,772
Other expense (Note 9)	(3,878)	(2,945)
Total	19,225	28,103
INTEREST EXPENSE		
Interest charges	56,665	56,158
Allowance for borrowed funds used during construction	(6,665)	(6,755)
Total	50,000	49,403
INCOME BEFORE INCOME TAXES	34,602	16,578
INCOME TAXES	1,453	2,106
NET INCOME	33,149	14,472
Less: Net income attributable to noncontrolling interests (Note 6)	4,873	4,873
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 28,276	$ 9,599

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

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

	Three Months Ended March 31,	
	2019	**2018**
NET INCOME	$ 33,149	$ 14,472
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Derivative instruments:		
Net unrealized loss, net of tax expense of $0 and $96	—	(96)
Reclassification of net realized loss, net of tax benefit of $108 and $82	328	409
Pension and other postretirement benefits activity, net of tax expense of $247 and $306	752	857
Total other comprehensive income	1,080	1,170
COMPREHENSIVE INCOME	34,229	15,642
Less: Comprehensive income attributable to noncontrolling interests	4,873	4,873
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 29,356	$ 10,769

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

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

	March 31, 2019	December 31, 2018
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	$ 18,760,012	$ 18,733,142
Accumulated depreciation and amortization	(6,395,265)	(6,362,771)
Net	12,364,747	12,370,371
Construction work in progress	1,233,018	1,170,062
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	104,808	105,775
Intangible assets, net of accumulated amortization	267,842	262,746
Nuclear fuel, net of accumulated amortization	142,610	120,217
Total property, plant and equipment	14,113,025	14,029,171
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Notes 11 and 12)	919,309	851,134
Other special use funds (Notes 11 and 12)	238,207	236,101
Other assets	42,090	40,817
Total investments and other assets	1,199,606	1,128,052
CURRENT ASSETS		
Cash and cash equivalents	6,080	5,707
Customer and other receivables	238,270	257,654
Accrued unbilled revenues	114,077	137,170
Allowance for doubtful accounts	(2,455)	(4,069)
Materials and supplies (at average cost)	280,857	269,065
Fossil fuel (at average cost)	26,294	25,029
Assets from risk management activities (Note 7)	763	1,113
Deferred fuel and purchased power regulatory asset (Note 4)	7,583	37,164
Other regulatory assets (Note 4)	127,642	129,738
Other current assets	44,417	35,111
Total current assets	843,528	893,682
DEFERRED DEBITS		
Regulatory assets (Note 4)	1,321,507	1,342,941
Operating lease right-of-use assets (Note 16)	191,957	—
Assets for other postretirement benefits (Note 5)	48,961	43,212
Other	38,299	128,265
Total deferred debits	1,600,724	1,514,418
TOTAL ASSETS	$ 17,756,883	$ 17,565,323

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

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

	March 31, 2019	December 31, 2018
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	2,721,696	2,721,696
Retained earnings	2,816,532	2,788,256
Accumulated other comprehensive loss	(26,027)	(27,107)
Total shareholder equity	5,690,363	5,661,007
Noncontrolling interests (Note 6)	130,663	125,790
Total equity	5,821,026	5,786,797
Long-term debt less current maturities (Note 3)	4,437,155	4,189,436
Total capitalization	10,258,181	9,976,233
CURRENT LIABILITIES		
Short-term borrowings (Note 3)	157,500	—
Current maturities of long-term debt (Note 3)	250,000	500,000
Accounts payable	257,124	266,277
Accrued taxes	230,591	176,357
Accrued interest	47,585	60,228
Common dividends payable	—	82,700
Customer deposits	87,263	91,174
Liabilities from risk management activities (Note 7)	33,289	35,506
Liabilities for asset retirements	22,823	19,842
Operating lease liabilities (Note 16)	65,267	—
Regulatory liabilities (Note 4)	260,404	165,876
Other current liabilities	114,665	178,137
Total current liabilities	1,526,511	1,576,097
DEFERRED CREDITS AND OTHER		
Deferred income taxes	1,815,368	1,812,664
Regulatory liabilities (Note 4)	2,272,082	2,325,976
Liabilities for asset retirements	712,885	706,703
Liabilities for pension benefits (Note 5)	367,296	425,404
Liabilities from risk management activities (Note 7)	14,844	24,531
Customer advances	155,894	137,153
Coal mine reclamation	214,037	212,785
Deferred investment tax credit	200,052	200,405
Unrecognized tax benefits	42,084	41,861
Operating lease liabilities (Note 16)	51,805	—
Other	125,844	125,511
Total deferred credits and other	5,972,191	6,012,993
COMMITMENTS AND CONTINGENCIES (SEE NOTE 8)		
TOTAL LIABILITIES AND EQUITY	$ 17,756,883	$ 17,565,323

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

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

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 33,149	$ 14,472
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	167,779	162,853
Deferred fuel and purchased power	16,709	(18,950)
Deferred fuel and purchased power amortization	12,872	20,002
Allowance for equity funds used during construction	(11,188)	(14,079)
Deferred income taxes	(1,205)	533
Deferred investment tax credit	(353)	(147)
Changes in current assets and liabilities:		
Customer and other receivables	16,541	90,647
Accrued unbilled revenues	23,093	(6,555)
Materials, supplies and fossil fuel	(13,057)	(16,747)
Other current assets	(9,598)	(1,237)
Accounts payable	30,774	(24,592)
Accrued taxes	54,234	54,106
Other current liabilities	(81,627)	(15,771)
Change in other long-term assets	(64,516)	3,722
Change in other long-term liabilities	14,525	(70,928)
Net cash flow provided by operating activities	188,132	177,329
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(259,446)	(355,039)
Contributions in aid of construction	7,938	8,569
Allowance for borrowed funds used during construction	(6,665)	(6,755)
Proceeds from nuclear decommissioning trust sales and other special use funds	179,048	130,456
Investment in nuclear decommissioning trust and other special use funds	(179,618)	(131,027)
Other	(1,140)	(1,183)
Net cash flow used for investing activities	(259,883)	(354,979)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	497,324	—
Short-term borrowings and payments — net	157,500	255,500
Short-term debt borrowings under revolving credit facility	—	25,000
Short-term debt repayments under revolving credit facility	—	(25,000)
Repayment of long-term debt	(500,000)	—
Dividends paid on common stock	(82,700)	(77,700)
Net cash flow provided by financing activities	72,124	177,800
NET INCREASE IN CASH AND CASH EQUIVALENTS	373	150
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	5,707	13,851
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 6,080	$ 14,001

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)

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, January 1, 2018	71,264,947	$ 178,162	$ 2,571,696	$ 2,533,954	$ (26,983)	$ 129,040	$ 5,385,869
Net income		—	—	9,599	—	4,873	14,472
Other comprehensive income		—	—	—	1,170	—	1,170
Other		—	—	—	—	1	1
Reclassification of income tax effects related to new tax reform (a)		—	—	5,038	(5,038)	—	—
Balance, March 31, 2018	71,264,947	$ 178,162	$ 2,571,696	$ 2,548,591	$ (30,851)	$ 133,914	$ 5,401,512
Balance, January 1, 2019	71,264,947	$ 178,162	$ 2,721,696	$ 2,788,256	$ (27,107)	$ 125,790	$ 5,786,797
Net income		—	—	28,276	—	4,873	33,149
Other comprehensive income		—	—	—	1,080	—	1,080
Balance, March 31, 2019	71,264,947	$ 178,162	$ 2,721,696	$ 2,816,532	$ (26,027)	$ 130,663	$ 5,821,026

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

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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Consolidation and Nature of Operations

The unaudited condensed consolidated financial statements include the accounts of Pinnacle West and our subsidiaries: APS, 4C Acquisition, LLC ("4CA"), Bright Canyon Energy Corporation ("BCE") and El Dorado Investment Company ("El Dorado"). See Note 8 for more information on 4CA matters. Intercompany accounts and transactions between the consolidated companies have been eliminated. The unaudited condensed consolidated financial statements for APS include the accounts of APS and the Palo Verde Generating Station ("Palo Verde") sale leaseback variable interest entities ("VIEs") (see Note 6 for further discussion). Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Amounts reported in our interim Condensed Consolidated Statements of Income are not necessarily indicative of amounts expected for the respective annual periods, due to the effects of seasonal temperature variations on energy consumption, timing of maintenance on electric generating units, 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 2018 Form 10-K.

Supplemental Cash Flow Information

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

	Three Months Ended March 31,	
	2019	2018
Cash paid during the period for:		
Income taxes, net of refunds	$ 1	$ —
Interest, net of amounts capitalized	63,764	56,026
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 95,879	$ 86,991
Right-of-use operating lease assets obtained in exchange for operating lease liabilities	2,293	—

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

	Three Months Ended March 31,	
	2019	2018
Cash paid during the period for:		
Income taxes, net of refunds	$ —	$ —
Interest, net of amounts capitalized	61,387	54,873
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 95,879	$ 86,944
Right-of-use operating lease assets obtained in exchange for operating lease liabilities	2,293	—

2. Revenue

Sources of Revenue

We derive our revenues from contracts with customers primarily from sales of electricity to our regulated retail customers. Our retail electric services and tariff rates are regulated by the ACC. Revenues from wholesale energy sales and transmission services for others represent energy and transmission sales to wholesale customers. Our wholesale activities and tariff rates are regulated by the United States Federal Energy Regulatory Commission ("FERC").

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

	Three Months Ended March 31,	
	2019	2018
Retail residential electric service	$ 351,566	$ 316,675
Retail non-residential electric service	332,668	343,189
Wholesale energy sales	36,452	12,089
Transmission services for others	15,249	14,845
Other sources	4,595	5,916
Total operating revenues	$ 740,530	$ 692,714

Revenue Activities

Our revenues are primarily derived from activities that are classified as revenues from contracts with customers. This includes sales of electricity to our regulated retail customers and wholesale and transmission activities. Our revenues from contracts with customers for the three months ended March 31, 2019 and 2018 were $721 million and $683 million, respectively.

We have certain revenues that do not meet the specific accounting criteria to be classified as revenues from contracts with customers. For the three months ended March 31, 2019 and 2018, our revenues that do not qualify as revenue from contracts with customers were $20 million and $10 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 March 31, 2019 or December 31, 2018.

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

At March 31, 2019, Pinnacle West had a 364-day $150 million revolving credit facility that matures June 27, 2019. Borrowings under the facility bear interest at LIBOR plus 0.70% per annum. At March 31, 2019, Pinnacle West had $49 million in outstanding borrowings under the facility.

At March 31, 2019, Pinnacle West had a $200 million revolving credit facility that matures in July 2023. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on Pinnacle West's senior unsecured debt credit ratings. The facility is available to support Pinnacle West's $200 million commercial paper program, for bank borrowings or for issuances of letters of credits. At March 31, 2019, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and $38 million of commercial paper borrowings.

APS

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

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

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

At March 31, 2019, APS had two revolving credit facilities totaling $1 billion, including a $500 million credit facility that matures in June 2022 and a $500 million facility that matures in July 2023. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings. These facilities are available to support APS's $500 million commercial paper program, for bank borrowings or for issuances of letters of credit. At March 31, 2019, APS had $158 million of commercial paper outstanding and no outstanding borrowings or letters of credit under its revolving credit facilities.

See "Financial Assurances" in Note 8 for a discussion of APS's 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 March 31, 2019		As of December 31, 2018	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 448,953	$ 446,835	$ 448,796	$ 443,955
APS	4,687,155	4,942,057	4,689,436	4,789,608
Total	$ 5,136,108	$ 5,388,892	$ 5,138,232	$ 5,233,563

4. Regulatory Matters

Retail Rate Case Filing with the Arizona Corporation Commission

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

Agreement provides for a net retail base rate increase of $94.6 million, excluding the transfer of adjustor balances, consisting of: (1) a non-fuel, non-depreciation, base rate increase of $87.2 million per year; (2) a base rate decrease of $53.6 million attributable to reduced fuel and purchased power costs; and (3) a base rate increase of $61.0 million due to changes in depreciation schedules. The average annual customer bill impact under the 2017 Settlement Agreement was calculated as an increase of 3.28% (the average annual bill impact for a typical APS residential customer was calculated as an increase of 4.54%).

Other key provisions of the agreement include the following:

- an agreement by APS not to file another general retail rate case application before June 1, 2019;
- an authorized return on common equity of 10.0%;
- a capital structure comprised of 44.2% debt and 55.8% common equity;
- a cost deferral order for potential future recovery in APS's next general retail rate case for the construction and operating costs APS incurs for its Ocotillo modernization project;
- a cost deferral and procedure to allow APS to request rate adjustments prior to its next general retail rate case related to its share of the construction costs associated with installing selective catalytic reduction ("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 battery 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, and not more than $15 million per year;
- 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 October 17, 2017, Warren Woodward (an intervener in APS's general retail rate case) filed a Notice of Appeal in the Arizona Court of Appeals, Division One. The notice raises a single issue related to the application of certain rate schedules to new APS residential customers after May 1, 2018. Mr. Woodward filed a second notice of appeal on November 13, 2017 challenging APS's $5 per month automated metering infrastructure opt-out program. Mr. Woodward's two appeals have been consolidated, and APS requested and was granted intervention. Mr. Woodward filed his opening brief on March 28, 2018. The ACC and APS filed responsive briefs on June 21, 2018. The Arizona Court of Appeals issued a Memorandum Decision on December 11, 2018 affirming the ACC decisions challenged by Mr. Woodward. Mr. Woodward filed a petition for review with the Arizona Supreme Court on January 9, 2019. Review by the Arizona Supreme Court is discretionary. APS cannot predict the outcome of this consolidated appeal but does not believe it will have a material impact on our financial position, results of operations or cash flows.

On January 3, 2018, an APS customer filed a petition with the ACC that was determined by the ACC Staff to be a complaint filed pursuant to Arizona Revised Statute §40-246 (the "Complaint") and not a request for rehearing. Arizona Revised Statute §40-246 requires the ACC to hold a hearing regarding any complaint alleging that a public service corporation is in violation of any commission order or that the rates being charged are not just and reasonable if the complaint is signed by at least twenty-five customers of the public service corporation. The Complaint alleged that APS is "in violation of commission order" [sic]. On February 13, 2018, the complainant filed an amended Complaint alleging that the rates and charges in the 2017 Rate Case Decision are not just and reasonable. The complainant requested that the ACC hold a hearing on the amended Complaint to determine if the average bill impact on residential customers of the rates and charges approved in the 2017 Rate Case Decision is greater than 4.54% (the average annual bill impact for a typical APS residential customer estimated by APS) and, if so, what effect the alleged greater bill impact has on APS's revenues and the overall reasonableness and justness of APS's rates and charges, in order to determine if there is sufficient evidence to warrant a full-scale rate hearing. The ACC held a hearing on this matter beginning in September 2018 and the hearing was concluded on October 1, 2018. Post-hearing briefing was concluded on December 14, 2018. On April 9, 2019, the Administrative Law Judge issued a Recommended Opinion and Order recommending that the Complaint be dismissed. On April 22, 2019, the Administrative Law Judge issued a proposed amendment to the Recommended Opinion and Order which proposes that APS credit back to customers the $5 million Demand Side Management Adjustor Charge ("DSMAC") funds used by APS to educate ratepayers on the new rates and that APS ratepayers will be held harmless from expenditures made by APS for targeted outreach and education in any future rate case. APS cannot predict the outcome of this matter.

On December 24, 2018, certain ACC Commissioners filed a letter stating that because the ACC had received a substantial number of complaints that the rate increase authorized by the 2017 Rate Case Decision was much more than anticipated, they believe there is a possibility that APS is earning more than was authorized by the 2017 Rate Case Decision. Accordingly, the ACC Commissioners requested the ACC Staff to perform a rate review of APS using calendar year 2018 as a test year and file a report by May 3, 2019. The ACC Commissioners also asked the ACC Staff to evaluate APS's efforts to educate its customers regarding the new rates approved in the 2017 Rate Case Decision. On January 9, 2019, the ACC Commissioners voted to open a docket for this matter. On April 23, 2019, the ACC Staff indicated that they may need some additional time beyond May 3, 2019 to file the requested report. APS does not believe that the rate review will have a material impact on our current financial position, results of operations or cash flows. However, depending upon the results of the rate review, the ACC may take further actions, including potentially reopening the 2017 Rate Case Decision. APS cannot predict the outcome of this matter.

Cost Recovery Mechanisms

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

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 utility compliance with the RES.

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

On November 20, 2017, APS filed an updated 2018 RES budget to include budget adjustments for APS Solar Communities (formerly known as AZ Sun II), which was approved as part of the 2017 Rate Case Decision. APS Solar Communities is a 3-year program authorizing APS to spend $10 million to $15 million in capital costs each year to install utility-owned DG systems for low to moderate income residential homes, buildings of non-profit entities, Title I schools and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES. On June 12, 2018, the ACC approved the 2018 RES Implementation Plan including a waiver of the distributed energy requirements for the 2018 implementation year.

On June 29, 2018, APS filed its 2019 RES Implementation Plan and proposed a budget of approximately $89.9 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the residential distributed energy requirement for 2019 contained in the RES rules. The ACC has not yet ruled on the 2019 RES Implementation Plan.

In September 2016, the ACC initiated a proceeding which will examine the possible modernization and expansion of the RES. On January 30, 2018, ACC Commissioner Tobin proposed a plan in this proceeding which would broaden the RES to include a series of energy policies tied to clean energy sources (the "Energy Modernization Plan"). The Energy Modernization Plan would replace the current RES standard with a new standard called the Clean Resource Energy Standard and Tariff ("CREST"), which incorporates the proposals in the Energy Modernization Plan. A set of draft CREST rules for the ACC's consideration was issued by Commissioner Tobin's office on July 5, 2018. See "Energy Modernization Plan" below for more information.

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

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

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

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 (liability) for 2019 and 2018 (dollars in thousands):

	Three Months Ended March 31,	
	2019	**2018**
Beginning balance	$ 37,164	$ 75,637
Deferred fuel and purchased power costs — current period	(16,709)	18,950
Amounts charged to customers	(12,872)	(20,002)
Ending balance	$ 7,583	$ 74,585

The PSA rate for the PSA year beginning February 1, 2017 was $(0.001348) per kWh, as compared to $0.001678 per kWh for the prior year. This rate was comprised of a forward component of $(0.001027) per kWh and a historical component of $(0.000321) per kWh. On August 19, 2017 the PSA rate was revised to $0.000555 per kWh as part of the 2017 Rate Case Decision. This new rate was comprised of a forward component of $0.000876 per kWh and a historical component of $(0.000321) per kWh.

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

On November 30, 2018, APS filed its PSA rate for the PSA year beginning February 1, 2019. That rate was $0.001658 per kWh and consisted of a forward component of $0.000536 per kWh and a historical component of $0.001122 per kWh. The 2019 PSA rate is a $0.002897 per kWh decrease compared to 2018. These rates went into effect as filed on February 1, 2019.

Transmission Rates, Transmission Cost Adjustor ("TCA") and Other Transmission Matters. In July 2008, FERC approved an Open Access Transmission Tariff for 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 (the "2012 Settlement Agreement"), however, an adjustment to rates to recover the Retail Transmission Charges will be made annually each June 1 and will go into effect automatically unless suspended by the ACC.

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

Effective June 1, 2017, APS's annual wholesale transmission rates for all users of its transmission system increased by approximately $35.1 million for the twelve-month period beginning June 1, 2017 in accordance with the FERC-approved formula. An adjustment to APS’s retail rates to recover FERC approved transmission charges went into effect automatically on June 1, 2017.

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

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

Lost Fixed Cost Recovery Mechanism. The LFCR mechanism permits APS to recover on an after-the-fact basis a portion of its fixed costs that would otherwise have been collected by APS in the kWh sales lost due to APS energy efficiency programs and to DG such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism were first established in the 2012 Settlement Agreement and amount to approximately 3.1 cents per residential kWh lost and 2.3 cents per non-residential kWh lost. These amounts were revised in the 2017 Settlement Agreement to 2.5 cents for both lost residential and non-residential kWh. The LFCR adjustment has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWhs lost from energy efficiency are based on a third-party evaluation of APS’s energy efficiency programs. DG sales losses are determined from the metered output from the DG units.

APS filed its 2017 LFCR adjustment on January 13, 2017 requesting an LFCR adjustment of $63.7 million. On April 5, 2017, the ACC approved the 2017 annual LFCR adjustment as filed, effective with the first billing cycle of April 2017. 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 (a $3 million per year decrease from 2017 levels). 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). The ACC has not yet ruled on APS’s 2019 LFCR adjustment request. Because the LFCR mechanism has a balancing account that trues up any under or over recoveries, the delay in implementation does not have an adverse effect on APS.

Tax Expense Adjustor Mechanism ("TEAM"). 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 reduces 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. The impact of TEAM Phase II is expected to be earnings neutral as 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 addresses the amortization of depreciation related excess deferred taxes over a 28.5 year period (“TEAM Phase III”). Over the first 36 months, TEAM Phase III is expected to return $34.5 million to customers annually, and APS has proposed this refund begin July 1, 2019. The Company is currently in the process of seeking IRS guidance affirming the amortization method and period applicable to these depreciation related excess deferred taxes. The ACC has not yet approved TEAM Phase III.

Net Metering

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

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

In addition, the ACC made the following determinations:

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

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

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

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.

Subpoena from Arizona Corporation Commissioner Robert Burns

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

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

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

On August 4, 2017, Commissioner Burns amended his complaint to add all of the ACC Commissioners and the ACC itself as defendants. All defendants moved to dismiss the amended complaint. On February 15, 2018, the Superior Court dismissed Commissioner Burns' amended complaint. On March 6, 2018, Commissioner Burns filed an objection to the proposed final order from the Superior Court and a motion to further amend his complaint. The Superior Court permitted Commissioner Burns to amend his complaint to add a claim regarding his attempted investigation into whether his fellow commissioners should have been disqualified from voting on APS's 2017 rate case. Commissioner Burns filed his second amended complaint, and all defendants filed responses opposing the second amended complaint and requested that it be dismissed. Oral argument occurred in November 2018 regarding the motion to dismiss. On December 18, 2018, the trial court granted the defendants' motions to dismiss and entered final judgment on January 18, 2019. On February 13, 2019, Commissioner Burns filed a notice of appeal. APS and Pinnacle West cannot predict the outcome of this matter.

Information Requests from Arizona Corporation Commissioners

On January 14, 2019, ACC Commissioner Kennedy opened a docket to investigate campaign expenditures and political participation of APS and Pinnacle West. In addition, on February 27, 2019, ACC Commissioners Burns and Dunn opened a new docket and requested documents from APS and Pinnacle West related to ACC elections and charitable contributions related to the ACC. On March 1, 2019, ACC Commissioner Kennedy issued a subpoena to APS seeking several categories of information for both Pinnacle West and APS including political contributions, lobbying expenditures, marketing and advertising expenditures, and contributions made to 501(c)(3) and 501(c)(4) entities, for the years 2013-2018. Pinnacle West and APS voluntarily responded to both sets of requests on March 29, 2019. APS received subsequent requests on these matters and continues to respond to such follow-on requests. Pinnacle West and APS cannot predict the outcome of these matters.

Renewable Energy Ballot Initiative

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

Energy Modernization Plan

On January 30, 2018, ACC Commissioner Tobin proposed the Energy Modernization Plan, which consists 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 plans ("IRP") process. The Energy Modernization Plan includes replacing the current RES standard with a new standard called the CREST, which incorporates the proposals in the Energy Modernization Plan. On July 5, 2018, ACC Commissioner Tobin's office issued a set of draft CREST rules for the ACC's consideration, which proposes an electricity generating portfolio of at least 80% clean energy sources (including nuclear generation) by 2050, a target of 3,000 megawatts of deployed energy storage by 2030, and a plan to implement a new Energy Efficiency Standard when the current standard sunsets in 2020.

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 Renewable Energy Standard, Electric and Gas Energy Efficiency Standards, Net Metering, Resource Planning, and the Biennial Transmission Assessment, as well as the development of new rules regarding forest bioenergy, electric vehicles, interconnection of distributed generation, baseload security, blockchain technology and other technological developments, retail competition, and other energy-related topics. On April 25, 2019, the ACC Staff issued a set of draft rules in regards to the Energy Modernization Plan and workshops were held on April 29, 2019 regarding these draft rules. On April 26, 2019, Commissioner Dunn issued a proposed set of rules with regards to the Energy Modernization Plan. APS cannot predict the outcome of this matter.

Integrated Resource Planning

ACC rules require utilities to develop fifteen-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. In March of 2018, the ACC reviewed the 2017 IRPs of its jurisdictional utilities and voted to not acknowledge any of the plans. APS does not believe that this lack of acknowledgment will have a material impact on our financial position, results of operations or cash flows. Based on an ACC decision, APS is required to file a Preliminary Resource Plan by April 1, 2019 and its final IRP by April 1, 2020. On February 25, 2019, APS filed a request to extend the deadline to file its Preliminary Integrated Resource Plan from April 1, 2019 to August 1, 2019. On April 24, 2019, the ACC approved this request.

Four Corners

SCE-Related Matters. On December 30, 2013, APS purchased Southern California Edison Company's ("SCE's") 48% ownership interest in each of Units 4 and 5 of Four Corners. The 2012 Settlement Agreement includes a procedure to allow APS to request rate adjustments prior to its next general retail rate case related to APS's acquisition of the additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners. APS made its filing under this provision on December 30, 2013. On December 23, 2014, the ACC approved rate adjustments resulting in a revenue increase of $57.1 million on an annual basis. This included the deferral for future recovery of all non-fuel operating costs for the acquired SCE interest in Four Corners, net of the non-fuel operating costs savings resulting from the closure of Units 1-3 from the date of closing of the purchase through its inclusion in rates. The 2012 Settlement Agreement also provided for deferral for future recovery of all unrecovered costs incurred in connection with the closure of Units 1-3. The deferral balance related to the acquisition of SCE's interest in Units 4 and 5 and the closure of Units 1-3 was $46 million as of March 31, 2019 and is being amortized in rates over a total of 10 years. The ACC's rate adjustment decision was appealed and on September 26, 2017, the Court of Appeals affirmed the ACC's decision on the Four Corners rate adjustment.

As part of APS's acquisition of SCE's interest in Units 4 and 5, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS established a regulatory asset of $12 million in 2015 in connection with the payment required under the terms of the Transmission Agreement. On July 1, 2016, FERC issued an order denying APS's request to recover the regulatory asset through its FERC-jurisdictional rates. APS and SCE completed the termination of the Transmission Agreement on July 6, 2016. APS made the required payment to SCE and wrote-off the $12 million regulatory asset and charged operating revenues to reflect the effects of this order in the second quarter of 2016. On July 29, 2016, APS filed a request for rehearing with FERC. In its order denying recovery, FERC also referred to its enforcement division a question of whether the agreement between APS and SCE relating to the settlement of obligations under the Transmission Agreement was a jurisdictional contract that should have been filed with FERC. On October 5, 2017, FERC issued an order denying APS's request for rehearing. FERC also upheld its prior determination that the agreement relating to the settlement was a jurisdictional contract and should have been filed with FERC. APS cannot predict whether or if the enforcement division will take any action. APS filed an appeal of FERC's July 1, 2016 and October 5, 2017 orders with the United States Court of Appeals for the Ninth Circuit on December 4, 2017. Oral argument for this proceeding is scheduled for May 15, 2019. APS cannot predict the outcome of the proceeding.

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 anticipates a decision later in 2019, however we cannot predict the outcome of the decision. APS may be required to record a charge to its results of operations if the ACC issues an unfavorable decision (see SCR deferral in the Regulatory Assets and Liabilities table below).

Cholla

On September 11, 2014, APS announced that it would close Unit 2 of 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") approves 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.

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 ($85 million as of March 31, 2019), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2’s remaining net book value was reclassified from property, plant and equipment to a regulatory asset. The 2017 Settlement Agreement also shortened the depreciation lives of Cholla Units 1 and 3 to 2026.

On March 20, 2019, APS announced that it has begun evaluating the feasibility and cost of converting a unit at the Cholla to burn biomass. Biomass is a fuel comprised of forest trimmings, and a converted unit at Cholla could assist in forest thinning, responsible forest management, an improved watershed, and a reduced wildfire risk. APS’s ability to operate a biomass power plant would depend on third-parties procuring forest biomass for fuel. APS will report the result of its evaluation by May 20, 2019. If converting a unit is more cost effective than alternatives, APS will seek ACC approval before moving forward with the Cholla conversion project. APS cannot predict the outcome of this matter.

Navajo Plant

The co-owners of the Navajo Generating Station (the "Navajo Plant") and the Navajo Nation agreed that the Navajo Plant will remain in operation until December 2019 under the existing plant lease. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017 that will allow for decommissioning activities to begin after the plant ceases operations in December 2019.

On February 14, 2017, the ACC opened a docket titled "ACC Investigation Concerning the Future of the Navajo Generating Station" with the stated goal of engaging stakeholders and negotiating a sustainable pathway for the Navajo Plant to continue operating in some form after December 2019. APS cannot predict the outcome of this proceeding.

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 ($85 million as of March 31, 2019) plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and may be material. APS believes it will be allowed recovery of the net book value, in addition to a return on its investment. In accordance with GAAP, in the second quarter of 2017, APS's remaining net book value of its interest in the Navajo Plant was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of this interest, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted.

Regulatory Assets and Liabilities

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

		March 31, 2019		December 31, 2018	
	Amortization Through	Current	Non-Current	Current	Non-Current
Pension	(a)	$ —	$ 723,307	$ —	$ 733,351
Retired power plant costs	2033	28,182	160,167	28,182	167,164
Income taxes — allowance for funds used during construction ("AFUDC") equity	2049	6,457	151,541	6,457	151,467
Deferred fuel and purchased power — mark-to-market (Note 7)	2023	29,340	14,360	31,728	23,768
Deferred fuel and purchased power (b) (c)	2020	7,583	—	37,164	—
Four Corners cost deferral	2024	8,077	38,209	8,077	40,228
Income taxes — investment tax credit basis adjustment	2047	1,079	25,475	1,079	25,522
Lost fixed cost recovery (b)	2020	29,698	—	32,435	—
Palo Verde VIEs (Note 6)	2046	—	20,170	—	20,015
Deferred compensation	2036	—	37,581	—	36,523
Deferred property taxes	2027	8,569	64,214	8,569	66,356
Loss on reacquired debt	2038	1,637	13,259	1,637	13,668
Tax expense of Medicare subsidy	2024	1,235	6,122	1,235	6,176
TCA balancing account (b)	2020	306	—	3,860	772
AG-1 deferral	2022	2,654	5,155	2,654	5,819
Mead-Phoenix transmission line CIAC	2050	332	9,961	332	10,044
Coal reclamation	2026	1,546	17,392	1,546	15,607
SCR deferral	N/A	—	30,581	—	23,276
Tax expense adjuster mechanism (c)	2019	5,451	—	—	—
Other	Various	3,079	4,013	1,947	3,185
Total regulatory assets (d)		$ 135,225	$ 1,321,507	$ 166,902	$ 1,342,941

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

		March 31, 2019		December 31, 2018	
	Amortization Through	Current	Non-Current	Current	Non-Current
Excess deferred income taxes - ACC - Tax Cuts and Jobs Act	(a)	$ 91,401	$ 1,178,216	$ —	$ 1,272,709
Excess deferred income taxes - FERC - Tax Cuts and Jobs Act	2058	6,302	243,418	6,302	243,691
Asset retirement obligations	2057	—	337,844	—	278,585
Removal costs	(b)	50,701	156,578	39,866	177,533
Other postretirement benefits	(c)	37,864	116,478	37,864	125,903
Income taxes — deferred investment tax credit	2047	2,164	51,027	2,164	51,120
Income taxes — change in rates	2048	2,764	69,954	2,769	70,069
Spent nuclear fuel	2027	7,190	54,866	6,503	57,002
Renewable energy standard (a)	2020	47,943	—	44,966	20
Demand side management (a)	2020	1,581	24,146	14,604	4,123
Sundance maintenance	2030	6,657	11,637	1,278	17,228
Deferred gains on utility property	2022	3,923	5,975	4,423	6,581
Four Corners coal reclamation	2038	1,858	17,690	1,858	17,871
Tax expense adjustor mechanism (a)	2020	14	—	3,237	—
Other	Various	42	4,253	42	3,541
Total regulatory liabilities		$ 260,404	$ 2,272,082	$ 165,876	$ 2,325,976

(a) See “Cost Recovery Mechanisms” discussion above.
(b) In accordance with regulatory accounting guidance, APS accrues removal costs for its regulated assets, even if there is no legal obligation for removal.
(c) See Note 5.

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 an other postretirement benefit plan for the employees of Pinnacle West and our subsidiaries. Pinnacle West uses a December 31 measurement date for its pension and other postretirement benefit plans. The market-related value of our plan assets is their fair value at the measurement dates.

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

	Pension Benefits		Other Benefits	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2019	2018	2019	2018
Service cost — benefits earned during the period	$ 12,543	$ 14,213	$ 4,714	$ 5,105
Non-service costs (credits):				
Interest cost on benefit obligation	34,352	31,007	7,526	7,101
Expected return on plan assets	(42,893)	(45,667)	(9,603)	(10,520)
Amortization of:				
Prior service cost (credit)	—	—	(9,455)	(9,461)
Net actuarial loss	11,239	7,782	—	—
Net periodic benefit cost (credit)	$ 15,241	$ 7,335	$ (6,818)	$ (7,775)
Portion of cost (credit) charged to expense	$ 8,244	$ 2,242	$ (4,817)	$ (5,605)

Contributions

We have made voluntary contributions of $90 million to our pension plan year-to-date in 2019. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to a total of $350 million during the 2019-2021 period. We do not expect to make any contributions over the next three years 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. APS will retain the assets through 2023 under one lease and 2033 under the other two leases. APS will be required to make payments relating to these leases of approximately $23 million annually through 2023, and $16 million annually for the period 2024 through 2033. At the end of the lease period, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors.

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

As a result of consolidation, we eliminate lease accounting and instead recognize depreciation expense, resulting in an increase in net income for the three months ended March 31, 2019 and 2018 of $5 million, entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

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

	March 31, 2019	December 31, 2018
Palo Verde sale leaseback property plant and equipment, net of accumulated depreciation	$ 104,808	$ 105,775
Equity — Noncontrolling interests	130,663	125,790

Assets of the VIEs are restricted and may only be used for payment to the noncontrolling interest holders. These assets are reported on our 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 $299 million beginning in 2019, and up to $456 million over the lease extension terms.

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

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 fuels. Derivative instruments that meet certain hedge accounting criteria may be designated as cash flow hedges and are used to limit our exposure to cash flow variability on forecasted transactions. The changes in market value of such instruments have a high correlation to price changes in the hedged transactions. Derivative instruments are also entered into for economic hedging purposes. While economic hedges may mitigate exposure to fluctuations in commodity prices, these instruments have not been designated as accounting hedges. Contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow are netted, which reduces both revenues and fuel and purchased power costs in our 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.

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

		Quantity	
Commodity	**Unit of Measure**	**March 31, 2019**	**December 31, 2018**
Power	GWh	1,146	250
Gas	Billion cubic feet	233	218

Gains and Losses from Derivative Instruments

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

		Three Months Ended March 31,	
Commodity Contracts	**Financial Statement Location**	**2019**	**2018**
Loss Reclassified from Accumulated OCI into Income (Effective Portion Realized) (a)	Fuel and purchased power (b)	$ (436)	$ (491)

(a) During the three months ended March 31, 2019 and 2018, 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 a net loss of $1 million before income taxes will be reclassified from accumulated OCI as an offset to the effect of market price changes for the related hedged transactions. In accordance with the PSA, most of these amounts will be recorded as either a regulatory asset or liability and have no immediate effect on earnings.

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

Commodity Contracts	Financial Statement Location	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
Net Loss Recognized in Income	Operating revenues	$ —	$ (1,219)
Net Gain (Loss) Recognized in Income	Fuel and purchased power (a)	8,170	(34,089)
Total		$ 8,170	$ (35,308)

(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. Additionally, in the event of a default, our master netting arrangements would allow for the offsetting of all transactions executed under the master netting arrangement. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, trade receivables and trade payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting tables presented below.

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

As of March 31, 2019: (dollars in thousands)	**Gross Recognized Derivatives (a)**	**Amounts Offset (b)**	**Net Recognized Derivatives**	**Other (c)**	**Amount Reported on Balance Sheets**
Current assets	$ 3,658	$ (2,857)	$ 801	$ (38)	$ 763
Investments and other assets	1,016	(881)	135	—	135
Total assets	4,674	(3,738)	936	(38)	898
Current liabilities	(34,487)	2,857	(31,630)	(1,659)	(33,289)
Deferred credits and other	(15,725)	881	(14,844)	—	(14,844)
Total liabilities	(50,212)	3,738	(46,474)	(1,659)	(48,133)
Total	$ (45,538)	$ —	$ (45,538)	$ (1,697)	$ (47,235)

(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 $1,659 and cash margin provided to counterparties of ($38).

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

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting.
(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $1,310 and cash margin provided to counterparties of $156.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by counterparties and have risk management contracts with many counterparties. As of March 31, 2019, Pinnacle West has no counterparties with positive exposures of greater than 10% of risk management assets. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of our trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these counterparties could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of financial institutions, major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. To manage credit risk, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

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

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

	March 31, 2019
Aggregate fair value of derivative instruments in a net liability position	$ 50,212
Cash collateral posted	—
Additional cash collateral in the event credit-risk-related contingent features were fully triggered (a)	47,874

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

We also have energy-related non-derivative instrument contracts with investment grade credit-related contingent features, which could also require us to post additional collateral of approximately $102 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 of $57.4 million 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. APS’s share of this amount is $16.7 million. Amounts recovered in the lawsuit and settlement were recorded as adjustments to a regulatory liability and had no impact on the amount of reported net income. In addition, the settlement agreement, as amended, provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2019.

APS has submitted four claims pursuant to the terms of the August 18, 2014 settlement agreement, for four separate time periods during July 1, 2011 through June 30, 2018. The DOE has approved and paid $74.2 million for these claims (APS’s share is $21.6 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). APS submitted its most recent claim pursuant to the terms of the August 18, 2014 settlement agreement to the DOE on October 31, 2018 in the amount of $10.2 million (APS's share is $3.0 million). On February 11, 2019 and April 10, 2019 (in response to APS's request for reconsideration), the DOE approved in total a payment of $10.2 million (APS’s share is $3.0 million).

Nuclear Insurance

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act ("Price-Anderson Act"), which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry-wide retrospective payment plan. In accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident of up to approximately $14.1 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 $13.6 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 $24.8 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 $71.2 million of collateral assurance within 20 business days of a rating downgrade to non-investment grade. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions, sublimits and exclusions.

Contractual Obligations

As of March 31, 2019, our fuel and purchased power commitments have increased approximately $180 million from the information provided in our 2018 Form 10-K. This change primarily relates to new purchased power commitments. The majority of the changes relate to 2024 and thereafter.

Other than the item described above, there have been no material changes, as of March 31, 2019, outside the normal course of business in contractual obligations from the information provided in our 2018 Form 10-K. See Note 3 for discussion regarding changes in our long-term debt obligations.

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 in the fall or winter of 2019. We estimate that our costs related to this investigation and study will be approximately $2 million. We anticipate incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

On August 6, 2013, Roosevelt Irrigation District ("RID") filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID's groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS's current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, 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. In addition, APS and certain other parties not named in the remaining RID service provider lawsuit may be brought into the litigation via third-party complaints filed by the current direct defendants. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of both conventional pollutants and greenhouse gases, water quality, wastewater discharges, solid waste, hazardous waste, and 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 new pollution control requirements on Four Corners and the Navajo Plant. EPA will require these plants to install pollution control equipment that constitutes best available retrofit technology ("BART") to lessen the impacts of emissions on visibility surrounding the plants. 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 is approximately $400 million, the majority of which has already 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 Coal Supply Agreement - 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.

Navajo Plant. APS estimates that its share of costs for upgrades at the Navajo Plant, based on EPA's Federal Implementation Plan ("FIP"), could be up to approximately $200 million; however, given the future plans for the Navajo Plant, we do not expect to incur these costs. See "Navajo Plant" in Note 4 for information regarding future plans for the Navajo Plant.

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

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 consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments, and are the subject of recent regulatory and judicial activities described below.

On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation ("WIIN") Act into law, which contains a number of provisions requiring EPA to modify the self-implementing provisions of the Agency's current CCR rules under Subtitle D. Such modifications include new EPA authority to directly enforce the CCR rules through the use of administrative orders and providing states, like Arizona, where the Cholla facility is located, the option of developing CCR disposal unit permitting programs, subject to EPA approval. For facilities in states that do not develop state-specific permitting programs, EPA is required to develop a federal permit program, pending the availability of congressional appropriations. By contrast, for facilities located within the boundaries of Native American tribal reservations, such as the Navajo Nation, where the Navajo Plant and Four Corners facilities are located, EPA is required to develop a federal permit program regardless of appropriated funds.

ADEQ has initiated a process to evaluate how to develop a state CCR permitting program that would cover electric generating units ("EGUs"), including Cholla. While APS has been working with ADEQ on the development of this program, we are unable to predict when Arizona will be able to finalize and secure EPA approval for a state-specific CCR permitting program. With respect to the Navajo Nation, APS has sought clarification as to when and how EPA would be initiating permit proceedings for facilities on the reservation, including Four Corners. We are unable to predict at this time when EPA will be issuing CCR management permits for the facilities on the Navajo Nation. At this time, it remains unclear how the CCR provisions of the WIIN Act will affect APS and its management of CCR.

Based upon utility industry petitions for EPA to reconsider the RCRA Subtitle D regulations for CCR, which were premised in part on the CCR provisions of the 2016 WIIN Act, on September 13, 2017 EPA agreed to evaluate whether to revise these federal CCR regulations. On July 17, 2018, EPA finalized a revision to its RCRA Subtitle D regulations for CCR, the "Phase I, Part I" revision to its CCR regulations, deferring for future action a number of other proposed changes contemplated in a March 1, 2018 proposal. For the final rule issued on July 17, 2018, EPA established nationwide health-based standards for certain constituents of CCR subject to groundwater corrective action and delayed the closure deadlines for certain unlined CCR surface impoundments by 18 months (for example, those disposal units required to undergo forced closure). These changes to the federal regulations governing CCR disposal are unlikely to have a material impact on APS. As for those aspects of the March 2018 rulemaking proposal for which EPA has yet to take final action, it remains unclear which specific provisions of the federal CCR rules will ultimately be modified, how they will be modified, or when such modification will occur.

Pursuant to a June 24, 2016 order by the D.C. Circuit Court of Appeals in the litigation by industry- and environmental-groups challenging EPA’s CCR regulations, EPA is required to complete a rulemaking proceeding in the near future concerning whether or not boron must be included on the list of groundwater constituents that might trigger corrective action under EPA’s CCR rules. Simultaneously with the issuance of EPA's proposed modifications to the federal CCR rules in response to industry petitions, on March 1, 2018, EPA issued a proposed rule seeking comment as to whether or not boron should be included on this list. EPA is not required to take final action approving the inclusion of boron. Should EPA take final action adding boron to the list of groundwater constituents that might trigger corrective action, any resulting corrective action measures may increase APS's costs of compliance with the CCR rule at our coal-fired generating facilities. At this time APS cannot predict the eventual results of this rulemaking proceeding concerning boron.

On August 21, 2018, the D.C. Circuit Court issued its decision on the merits in this litigation. The Court upheld the legality of EPA’s CCR regulations, though it vacated and remanded back to EPA a number of specific provisions, which are to be corrected in accordance with the Court’s order. Among the issues affecting APS’s management of CCR, the D.C. Circuit’s decision vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments, even where those unlined impoundments have not otherwise violated a regulatory location restriction or groundwater protection standard (i.e., otherwise triggering forced closure). At this time, it remains unclear how this D.C. Circuit Court decision will affect APS’s operations or any financial impacts, as EPA has yet to take regulatory action on remand to revise its 2015 CCR regulations consistent with the Court’s order.

Based on this decision, on December 17, 2018, certain environmental groups filed an emergency motion with the D.C. Circuit to either stay or summarily vacate EPA's July 17, 2018 final rule extending the closure-initiation deadline for certain unlined CCR surface impoundments until October 2020. In response, EPA filed a motion to remand but not vacate that deadline extension regulation. On March 13, 2019, the Court issued its ruling on the pending motions concerning the October 2020 deadline for closure initiation and granted remand without vacatur. This ruling allows the current October 2020 deadline to remain in effect while EPA completes a rulemaking to revise or reaffirm this deadline in accordance with the August 2018 D.C. Circuit decision concerning the closure of unlined CCR surface impoundments. We cannot predict the outcome of EPA’s remand rulemaking concerning the October 2020 deadline for closure initiation.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $22 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $15 million. The Navajo Plant currently disposes of CCR in a dry landfill storage area. APS estimates that its share of incremental costs to comply with the CCR rule for the Navajo Plant is approximately $1 million. Additionally, the CCR rule requires ongoing, phased groundwater monitoring. By October 17, 2017, electric utility companies that own or operate CCR disposal units, such as APS, must have collected sufficient groundwater sampling data to initiate a detection monitoring program. To the extent that certain threshold constituents are identified through this initial detection monitoring at levels above the CCR rule's standards, the rule required the initiation of an assessment monitoring program by April 15, 2018.

APS recently 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, all such units must cease operating and initiate closure by October of 2020. APS currently estimates that the additional incremental costs to complete this corrective action and closure work, along with the costs to develop replacement CCR disposal capacity, could be approximately $5 million for both Cholla and Four Corners. APS initiated an assessment of corrective measures on January 14, 2019, and anticipates completing this assessment during the summer of 2019. During this assessment, APS will gather additional groundwater data, solicit input from the public, host public hearings, and select remedies. As such, this $5 million cost estimate may change based upon APS's performance of the CCR rule's corrective action assessment process. 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 any potential change to the cost estimate would have a material impact on our financial position, results of operations or cash flows.

Clean Power Plan. On June 2, 2014, EPA issued two proposed rules to regulate greenhouse gas ("GHG") emissions from modified and reconstructed EGUs pursuant to Section 111(b) of the Clean Air Act and existing fossil fuel-fired power plants pursuant to Clean Air Act Section 111(d). On August 3, 2015, EPA finalized carbon pollution standards for EGUs, the "Clean Power Plan". On October 10, 2017, EPA issued a proposal to repeal the Clean Power Plan and proposed replacement regulations on August 21, 2018. In addition, judicial challenges to the Clean Power Plan are pending before the D.C. Circuit, though that litigation is currently in abeyance while EPA develops regulatory action to potentially repeal and replace that regulation.

EPA's pending proposal to regulate carbon emissions from EGUs replaces the Clean Power Plan with standards that are based entirely upon measures that can be implemented to improve the heat rate of steam-electric power plants, specifically coal-fired EGUs. In contrast with the Clean Power Plan, EPA's proposed "Affordable Clean Energy Rule" would not involve utility-level generation dispatch shifting away from coal-fired generation and toward renewable energy resources and natural gas-fired combined cycle power plants. In addition, to address the New Source Review ("NSR") implications of power plant upgrades potentially necessary to achieve compliance with the proposed Affordable Clean Energy Rule standards, EPA also proposed to revise EPA's NSR regulations to more readily authorize the implementation of EGU efficiency upgrades.

We cannot predict the outcome of EPA's regulatory actions related to the August 2015 carbon pollution standards for EGU's, including any actions related to EPA's repeal proposal for the Clean Power Plan or additional rulemaking actions to approve the EPA's recently proposed Affordable Clean Energy Rule. In addition, we cannot predict whether the D.C. Circuit Court will continue to hold the litigation challenging the original Clean Power Plan in abeyance in light of EPA's repeal proposal, which is still pending.

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

Federal Agency Environmental Lawsuit Related to Four Corners

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

On September 15, 2016, NTEC, the company that owns the adjacent mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. On September 11, 2017, the Arizona District Court issued an order granting NTEC's motion, dismissing the litigation with prejudice, and terminating the proceedings. On November 9, 2017, the environmental group plaintiffs appealed the district court order dismissing their lawsuit. Oral argument for this appeal occurred on March 7, 2019. We cannot predict whether this appeal will be successful and, if it is successful, the outcome of further district court proceedings.

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

On July 16, 2018, several environmental groups filed a petition for review before the EPA Environmental Appeals Board ("EAB") concerning the NPDES wastewater discharge permit for Four Corners, which was reissued on June 12, 2018. The environmental groups allege that the permit was reissued in contravention of several requirements under the Clean Water Act and did not contain required provisions concerning EPA’s 2015 revised effluent limitation guidelines for steam-electric EGUs, 2014 existing-source regulations governing cooling-water intake structures, and effluent limits for surface seepage and subsurface discharges from coal-ash disposal facilities. To address certain of these issues through a reconsidered permit, EPA took action on December 19, 2018 to withdraw the NPDES permit reissued in June 2018. Withdrawal of the permit moots the EAB appeal, and EPA filed a motion to dismiss on that basis. The EAB thereafter dismissed the environmental group appeal on February 12, 2019. EPA indicated that, depending on the extent of public comments it receives concerning the permit proposal, it anticipates taking final action on a new NPDES permit by August 2019. At this time we cannot predict the outcome of EPA's reconsideration of the NPDES permit and whether reconsideration will have a material impact on our financial position, results of operations or cash flows.

Four Corners - 4CA Matter

On July 6, 2016, 4CA purchased El Paso's 7% interest in Four Corners. NTEC had the option to purchase the 7% interest within a certain timeframe pursuant to an option granted to NTEC. On December 29, 2015, NTEC provided notice of its intent to exercise the option. The purchase did not occur during the originally contemplated timeframe. Concurrent with the settlement of the 2016 Coal Supply Agreement matter described above, NTEC and 4CA agreed to allow for the purchase by NTEC of the 7% interest, consistent with the option. On June 29, 2018, 4CA and NTEC entered into an asset purchase agreement providing for the sale to NTEC of 4CA's 7% interest in Four Corners. Completion of the sale was subject to the receipt of approval by FERC, which was received on July 2, 2018, and the sale transaction closed on July 3, 2018. NTEC purchased the 7% interest at 4CA's book value, approximately $70 million, and is paying 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note. In connection with the sale, Pinnacle West guaranteed certain obligations that NTEC will have to the other owners of Four Corners, such as NTEC's 7% share of capital expenditures and operating and maintenance expenses. Pinnacle West's guarantee is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement.

The 2016 Coal Supply Agreement contained alternate pricing terms for the 7% interest in the event NTEC did not purchase the interest. Until the time that NTEC purchased the 7% interest, the alternate pricing provisions were applicable to 4CA as the holder of the 7% interest. These terms included a formula under which NTEC must make certain payments to 4CA for reimbursement of operations and maintenance costs and a specified rate of return, offset by revenue generated by 4CA's power sales. Such payments are due to 4CA at the end of each calendar year. A $10 million payment was due to 4CA at December 31, 2017, which NTEC satisfied by directing to 4CA a prepayment from APS of a portion of a future mine reclamation obligation. The balance of the amount under this formula due December 31, 2018 for calendar year 2017 was approximately $20 million, which was paid to 4CA on December 14, 2018. The balance of the amount under this formula for calendar year 2018 (up to the date that NTEC purchased the 7% interest) is approximately $10 million, which is due to 4CA at December 31, 2019.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support commodity contract collateral obligations and other transactions. As of March 31, 2019, standby letters of credit totaled $0.2 million and will expire in 2019. As of March 31, 2019, surety bonds expiring through 2020 totaled $17 million. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

We enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements. Most significantly, APS has agreed to indemnify the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

Pinnacle West has issued parental guarantees and has provided indemnification under certain surety bonds for APS which were not material at March 31, 2019. In connection with the sale of 4CA's 7% interest to NTEC, Pinnacle West is guaranteeing certain obligations that NTEC will have to the other owners of Four Corners. (See "Four Corners Coal Supply Agreement - 4CA Matter" above for information related to this guarantee.) A maximum obligation is not explicitly stated in the guarantee and, therefore, the overall maximum amount of the obligation under such guarantee cannot be reasonably estimated; however, we consider the fair value of this guarantee to be immaterial.

9. Other Income and Other Expense

The following table provides detail of Pinnacle West's Consolidated other income and other expense for the three months ended March 31, 2019 and 2018 (dollars in thousands):

	Three Months Ended March 31,	
	2019	**2018**
Other income:		
Interest income	$ 2,302	$ 1,891
Debt return on Four Corners SCR (Note 4)	4,844	2,092
Miscellaneous	23	2
Total other income	$ 7,169	$ 3,985
Other expense:		
Non-operating costs	$ (2,704)	$ (1,646)
Investment losses — net	(238)	(176)
Miscellaneous	(1,416)	(1,407)
Total other expense	$ (4,358)	$ (3,229)

The following table provides detail of APS's other income and other expense for the three months ended March 31, 2019 and 2018 (dollars in thousands):

	Three Months Ended March 31,	
	2019	**2018**
Other income:		
Interest income	$ 1,550	$ 1,678
Debt return on Four Corners SCR (Note 4)	4,844	2,092
Miscellaneous	22	2
Total other income	$ 6,416	$ 3,772
Other expense:		
Non-operating costs	$ (2,467)	$ (1,539)
Miscellaneous	(1,411)	(1,406)
Total other expense	$ (3,878)	$ (2,945)

10. Earnings Per Share

The following table presents the calculation of Pinnacle West's basic and diluted earnings per share for the three months ended March 31, 2019 and 2018 (in thousands, except per share amounts):

	Three Months Ended March 31,	
	2019	**2018**
Net income attributable to common shareholders	$ 17,918	$ 3,221
Weighted average common shares outstanding — basic	112,337	112,017
Net effect of dilutive securities:		
Contingently issuable performance shares and restricted stock units	398	476
Weighted average common shares outstanding — diluted	112,735	112,493
Earnings per weighted-average common share outstanding		
Net income attributable to common shareholders — basic	$ 0.16	$ 0.03
Net income attributable to common shareholders — diluted	$ 0.16	$ 0.03

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 — Unadjusted quoted prices in active markets for identical assets or liabilities.

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

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

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

Certain instruments have been valued using the concept of 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 trust and other special use funds. On an annual basis we apply fair value measurements to plan assets held in our retirement and other benefit plans. See Note 7 for fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

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

Risk Management Activities — Derivative Instruments

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

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

When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3. Our classification of instruments as Level 3 is primarily reflective of the long-term nature of our energy transactions.

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

Investments Held in Nuclear Decommissioning Trust and Other Special Use Funds

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

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

Fair Value Tables

The following table presents the fair value at March 31, 2019 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (a) (Level 3)	Other		Balance at March 31, 2019
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 3,598	$ 1,076	$ (3,776)	(a)	$ 898
Nuclear decommissioning trust:						
Equity securities	7,547	—	—	2,630	(b)	10,177
U.S. commingled equity funds	—	—	—	451,229	(c)	451,229
U.S. Treasury debt	155,231	—	—	—		155,231
Corporate debt	—	108,509	—	—		108,509
Mortgage-backed debt securities	—	113,002	—	—		113,002
Municipal bonds	—	70,375	—	—		70,375
Other fixed income	—	10,786	—	—		10,786
Subtotal nuclear decommissioning trust	162,778	302,672	—	453,859		919,309
Other special use funds:						
Equity securities	11,471	—	—	1,563	(b)	13,034
U.S. Treasury debt	208,945	—	—	—		208,945
Municipal bonds	—	16,228	—	—		16,228
Subtotal other special use funds	220,416	16,228	—	1,563		238,207
Total Assets	$ 383,194	$ 322,498	$ 1,076	$ 451,646		$ 1,158,414
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (43,524)	$ (6,688)	$ 2,079	(a)	$ (48,133)

(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, 2018 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (a) (Level 3)	Other		Balance at December 31, 2018
Assets						
Cash equivalents	$ 1,200	$ —	$ —	$ —		$ 1,200
Risk management activities — derivative instruments:						
Commodity contracts	—	3,140	2	(2,029)	(a)	1,113
Nuclear decommissioning trust:						
Equity securities	5,203	—	—	2,148	(b)	7,351
U.S. commingled equity funds	—	—	—	396,805	(c)	396,805
U.S. Treasury debt	148,173	—	—	—		148,173
Corporate debt	—	96,656	—	—		96,656
Mortgage-backed debt securities	—	113,115	—	—		113,115
Municipal bonds	—	79,073	—	—		79,073
Other fixed income	—	9,961	—	—		9,961
Subtotal nuclear decommissioning trust	153,376	298,805	—	398,953		851,134
Other special use funds:						
Equity securities	45,130	—	—	593	(b)	45,723
U.S. Treasury debt	173,310	—	—	—		173,310
Municipal bonds	—	17,068	—	—		17,068
Subtotal other special use funds	218,440	17,068	—	593		236,101
Total Assets	$ 373,016	$ 319,013	$ 2	$ 397,517		$ 1,089,548
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (52,696)	$ (8,216)	$ 875	(a)	$ (60,037)

(a) Represents counterparty netting, margin, and collateral. See Note 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. Significant changes in these inputs in isolation would result in significantly higher or lower fair value measurements. Changes in our derivative contract fair values, including changes relating to unobservable inputs, typically will not impact net income due to regulatory accounting treatment (see Note 4).

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

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

The following tables provide information regarding our significant unobservable inputs used to value our risk management derivative Level 3 instruments at March 31, 2019 and December 31, 2018:

	March 31, 2019 Fair Value (thousands)					
Commodity Contracts	**Assets**	**Liabilities**	**Valuation Technique**	**Significant Unobservable Input**	**Range**	**Weighted-Average**
Electricity:						
Forward Contracts (a)	$ 382	$ 5,206	Discounted cash flows	Electricity forward price (per MWh)	$19.77 - $67.40	$ 50.50
Natural Gas:						
Forward Contracts (a)	694	1,482	Discounted cash flows	Natural gas forward price (per MMBtu)	$1.90 - $2.97	$ 2.46
Total	$ 1,076	$ 6,688				

(a) Includes swaps and physical and financial contracts.

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

(a) Includes swaps and physical and financial contracts.

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

	Three Months Ended March 31,	
Commodity Contracts	**2019**	**2018**
Net derivative balance at beginning of period	$ (8,214)	$ (18,256)
Total net gains (losses) realized/unrealized:		
Deferred as a regulatory asset or liability	(1,579)	(2,322)
Settlements	518	782
Transfers into Level 3 from Level 2	(2)	(2,445)
Transfers from Level 3 into Level 2	3,665	2,487
Net derivative balance at end of period	$ (5,612)	$ (19,754)
Net unrealized gains included in earnings related to instruments still held at end of period	$ —	$ —

Transfers between levels in the fair value hierarchy shown in the table above reflect the fair market value at the beginning of the period and are triggered by a change in the lowest significant input as of the end of the period. We had no significant Level 1 transfers to or from any other hierarchy level. Transfers in or out of Level 3 are typically related to our long-dated energy transactions that extend beyond available quoted periods.

Financial Instruments Not Carried at Fair Value

The carrying value of our short-term borrowings approximate fair value and are classified within Level 2 of the fair value hierarchy. See Note 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 $57 million as of March 31, 2019 and $61 million as of December 31, 2018 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 Accounts, and an Active Union Employee Medical Account. Investments in debt securities are classified as available-for-sale securities. We record both debt and equity security investments at their fair value on our 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 - To fund the future costs APS expects to incur to decommission Palo Verde, APS established external decommissioning trusts in accordance with NRC regulations. Third-party investment managers are authorized to buy and sell securities per stated investment guidelines. The trust funds are invested in fixed income securities and equity securities. Earnings and proceeds from sales and maturities of securities are reinvested in the trusts. Because of the ability of APS to recover decommissioning costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including other-than-temporary impairments) in other regulatory liabilities.

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

Active Union Employee Medical Account - APS has investments restricted for paying active union employee medical costs. These investments were transferred from APS other postretirement benefit trust assets into the active union employee medical trust in January 2018 (see Note 7 in the 2018 Form 10-K). These investments may be used to pay active union employee medical costs incurred in the current period and in future periods. The account is invested primarily in fixed income securities. In accordance with the ratemaking treatment, APS has deferred the unrealized gains and losses (including other-than-temporary impairments) in other regulatory assets. Activities relating to active union employee medical account investments are included within the other special use funds in the table below.

APS

The following tables present the unrealized gains and losses based on the original cost of the investment and summarizes the fair value of APS's nuclear decommissioning trust and other special use fund assets at March 31, 2019 and December 31, 2018 (dollars in thousands):

	March 31, 2019					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 458,776	$ 11,471	$ 470,247		$ 273,817	$ (4)
Available for sale-fixed income securities	457,903	225,173	683,076	(a)	15,306	(2,250)
Other	2,630	1,563	4,193	(b)	—	—
Total	$ 919,309	$ 238,207	$1,157,516		$ 289,123	$ (2,254)

(a) As of March 31, 2019, the amortized cost basis of these available-for-sale investments is $670 million.
(b) Represents net pending securities sales and purchases.

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

(a) As of December 31, 2018, the amortized cost basis of these available-for-sale investments is $635 million.
(b) Represents net pending securities sales and purchases.

The following table sets forth APS's realized gains and losses relating to the sale and maturity of available-for-sale debt securities and equity securities, and the proceeds from the sale and maturity of these investment securities for the three months ended March 31, 2019 and 2018 (dollars in thousands):

	Three Months Ended March 31,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2019			
Realized gains	$ 1,103	$ —	$ 1,103
Realized losses	(1,405)	—	(1,405)
Proceeds from the sale of securities (a)	122,593	56,455	179,048
2018			
Realized gains	$ 814	$ 1	$ 815
Realized losses	(2,047)	—	(2,047)
Proceeds from the sale of securities (a)	130,456	2,555	133,011

(a) Proceeds are reinvested in the nuclear decommissioning trusts or other special use funds.

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

	Nuclear Decommissioning Trusts (a)	Coal Reclamation Escrow Accounts	Active Union Medical Trust	Total
Less than one year	$ 26,100	$ 20,085	$ 40,099	$ 86,284
1 year – 5 years	120,511	15,960	138,627	275,098
5 years – 10 years	120,342	3,581	—	123,923
Greater than 10 years	190,950	6,821	—	197,771
Total	$ 457,903	$ 46,447	$ 178,726	$ 683,076

(a) Includes certain fixed income investments that are not due at a single maturity date. These investments have been allocated within the table based on the final payment date of the instrument.

13. New Accounting Standards

Standards Adopted in 2019

ASU 2016-02, Leases

In February 2016, a new lease accounting standard was issued. This new standard supersedes the existing lease accounting model, and modifies both lessee and lessor accounting. The new standard requires a lessee to reflect most operating lease arrangements on the balance sheet by recording a right-of-use asset and a lease liability that is initially measured at the present value of lease payments. Among other changes, the new standard also modifies the definition of a lease, and requires expanded lease disclosures. Since the issuance of the new lease standard, additional lease related guidance has been issued relating to land easements and how entities may elect to account for these arrangements at transition, among other items. The new lease standard and related amendments were effective for us on January 1, 2019, with early application permitted. The standard must be adopted using a modified retrospective approach with a cumulative-effect adjustment to the opening balance of retained earnings determined at either the date of adoption, or the earliest period presented in the financial statements. The standard includes various optional practical expedients provided to facilitate transition. We adopted this standard, and related amendments, on January 1, 2019. See Note 16.

Standards Pending Adoption

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

In June 2016, a new accounting standard was issued that amends the measurement of credit losses on certain financial instruments. The new standard will require entities to use a current expected credit loss model to measure impairment of certain investments in debt securities, trade accounts receivables, and other financial instruments. The new standard is effective for us on January 1, 2020 and must be adopted using a modified retrospective approach for certain aspects of the standard, and a prospective approach for other aspects of the standard. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.

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

In August 2018, a new accounting standard was issued that clarifies how customers in a cloud computing service arrangement should account for implementation costs associated with the arrangement. To determine which implementation costs should be capitalized, the new guidance aligns the accounting with existing guidance pertaining to internal-use software. As a result of this new standard, certain cloud computing service arrangement implementation costs will now be subject to capitalization and amortized on a straight-line basis over the cloud computing service arrangement term. The new standard is effective for us on January 1, 2020, with early application permitted, and may be applied using either a retrospective or prospective transition approach. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.

14. Changes in Accumulated Other Comprehensive Loss

The following table shows the changes in Pinnacle West's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the three months ended March 31, 2019 and 2018 (dollars in thousands):

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Balance December 31, 2018	$ (45,997)		$ (1,711)		$ (47,708)
Amounts reclassified from accumulated other comprehensive loss	879	(a)	328	(b)	1,207
Balance March 31, 2019	$ (45,118)		$ (1,383)		$ (46,501)
Balance December 31, 2017	$ (42,440)		$ (2,562)		$ (45,002)
OCI (loss) before reclassifications	—		(96)		(96)
Amounts reclassified from accumulated other comprehensive loss	900	(a)	409	(b)	1,309
Reclassification of income tax effect related to tax reform	(7,954)	(c)	(598)	(c)	(8,552)
Balance March 31, 2018	$ (49,494)		$ (2,847)		$ (52,341)

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

The following table shows the changes in APS's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the three months ended March 31, 2019 and 2018 (dollars in thousands):

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Balance December 31, 2018	$ (25,396)		$ (1,711)		$ (27,107)
Amounts reclassified from accumulated other comprehensive loss	752	(a)	328	(b)	1,080
Balance March 31, 2019	$ (24,644)		$ (1,383)		$ (26,027)
Balance December 31, 2017	$ (24,421)		$ (2,562)		$ (26,983)
OCI (loss) before reclassifications	—		(96)		(96)
Amounts reclassified from accumulated other comprehensive loss	857	(a)	409	(b)	1,266
Reclassification of income tax effect related to tax reform	(4,440)	(c)	(598)	(c)	(5,038)
Balance March 31, 2018	$ (28,004)		$ (2,847)		$ (30,851)

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

15. Income Taxes

The Tax Cuts and Jobs 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. On April 10, 2019, the Company filed a request with the ACC which addresses the amortization of depreciation related excess deferred taxes. See Note 4 for more details.

In August 2018, Treasury proposed regulations that clarify bonus depreciation transition rules under the Tax Act for regulated public utility property placed in service after September 27, 2017 and before January 1, 2018. However, the proposed regulations are ambiguous with respect to regulated public utility property placed in service on or after January 1, 2018. On December 20, 2018, the Joint Committee on Taxation ("JCT") released the general explanation of the Tax Act. The document - commonly referred to as the "Blue Book" - provides a comprehensive technical description of the Tax Act and includes the legislative intent of Congress with respect to the changes made by provisions of the Tax Act. The "Blue Book" provides clarification that the intent of the Tax Act was to exclude from the definition of bonus depreciation qualified property any property placed in service by a regulated public utility after December 31, 2017. In a footnote, the JCT indicated that a technical correction bill may be necessary to reflect this intent.

Management recognizes tax positions which it believes are “more likely than not” to be sustained upon examination. In applying this “more likely than not” assessment, the Company is required to consider the technical merits of a position, including legislative intent. As a result, while no legislation has been passed which clarifies the ambiguities related to bonus depreciation for property placed in service on or after January 1, 2018, the Company currently believes the continued availability of bonus depreciation is not “more likely than not” to be sustained upon examination. As a result, the Company has not recognized any current or deferred tax benefits related to bonus depreciation for property placed in service on or after January 1, 2018.

Net income associated with the Palo Verde sale leaseback VIEs is not subject to tax (see Note 6). 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.

As of the balance sheet date, the tax year ended December 31, 2015 and all subsequent tax years remain subject to examination by the IRS. With a few exceptions, we are no longer subject to state income tax examinations by tax authorities for years before 2014.

16. 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 2019 through 2050. Substantially all of our leasing activities relate to APS.

On January 1, 2019 we adopted new lease accounting guidance (see Note 13). We elected the transition method that allows us to apply the new lease guidance on the date of adoption, January 1, 2019, and will not retrospectively adjust prior periods. We also elected certain transition practical expedients that allow us to not reassess (a) whether any expired or existing contracts are or contain leases, (b) the lease classification for any expired or existing leases and (c) initial direct costs for any existing leases. These practical expedients apply to leases that commenced prior to January 1, 2019. Furthermore, we elected the practical expedient transition provisions relating to the treatment of existing land easements.

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

The following table provides information related to our lease costs for the three months ended March 31, 2019 (dollars in thousands):

	Three Months Ended March 31, 2019		
	Purchased Power Lease Contracts	**Land, Property & Equipment Leases**	**Total**
Operating lease cost	$ —	$ 4,348	$ 4,348
Variable lease cost	17,290	—	17,290
Total lease cost	$ 17,290	$ 4,348	$ 21,638

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). 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. Short-term lease cost is immaterial.

The following table provides information related to the maturity of our operating lease liabilities at March 31, 2019 (dollars in thousands):

	March 31, 2019		
Year	Purchased Power Lease Contracts	Land, Property & Equipment Leases	Total
2019 (remaining nine months of 2019)	$ 54,499	$ 10,539	$ 65,038
2020	—	12,424	12,424
2021	—	9,585	9,585
2022	—	6,621	6,621
2023	—	5,496	5,496
Thereafter	—	41,618	41,618
Total lease commitments	54,499	86,283	140,782
Less imputed interest	814	20,829	21,643
Total lease liabilities	$ 53,685	$ 65,454	$ 119,139

The following table provides information related to estimated future minimum operating lease payments at December 31, 2018 (dollars in thousands):

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

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

	March 31, 2019
Weighted average remaining lease term	8 years
Weighted average discount rate	3.86%

	Three Months Ended March 31, 2019
Cash paid for amounts included in the measurement of lease liabilities - operating cash flows (dollars in thousands):	$ 3,087

At March 31, 2019, we have additional lease arrangements that have been executed, but have not yet commenced. These arrangements primarily relate to purchased power lease contracts. These leases have commencement dates beginning in June 2020 with terms ending through October 2027.

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.

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 2018 Form 10-K.

OVERVIEW

Pinnacle West owns all of the outstanding common stock of APS. APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to most of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. APS currently accounts for essentially all of our revenues and earnings.

Areas of Business Focus

Operational Performance, Reliability and Recent Developments.

Nuclear. APS operates and is a joint owner of Palo Verde. Palo Verde experienced strong performance during 2018, with its three units achieving a combined year-end capacity factor of 90.2% and an all-time best collective radiation exposure dose performance in the history of Palo Verde's operation.

Coal and Related Environmental Matters and Transactions. APS is a joint owner of three coal-fired power plants and acts as operating agent for two of the plants. APS is focused on the impacts on its coal fleet that may result from increased regulation and potential legislation concerning GHG emissions. On August 3, 2015, EPA finalized a rule to limit carbon dioxide emissions from existing power plants (the "Clean Power Plan"), which the EPA later proposed repealing. EPA is considering a proposed replacement to the Clean Power Plan, which was published on August 21, 2018. This new proposal, the "Affordable Clean Energy Rule," is more narrow than its predecessor regulation, and is based entirely upon heat-rate improvements at steam-electric power plants. APS continually analyzes its long-range capital management plans to assess the potential effects of such proposals, understanding that any resulting regulation and legislation could impact the economic viability of certain plants, as well as the willingness or ability of power plant participants to continue participation in such plants.

Cholla

On September 11, 2014, APS announced that it would close its 260 megawatts ("MW") Unit 2 at Cholla and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit, which was later addressed in the 2017 Settlement Agreement. (See Note 4 for details related to the resulting cost recovery.) APS believes that the environmental benefits of this proposal are greater in the long-term than the benefits that would have resulted from adding emissions control equipment. APS closed Unit 2 on October 1, 2015. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect for Cholla on April 26, 2017.

On March 20, 2019, APS announced that it has begun evaluating the feasibility and cost of converting a unit at Cholla to burn biomass. Biomass is a fuel comprised of forest trimmings, and a converted unit at Cholla could assist in forest thinning, responsible forest management, an improved watershed, and a reduced wildfire risk. APS's ability to operate a biomass power plant would depend on third-parties procuring forest biomass for fuel. APS will report the result of its evaluation by May 20, 2019. If converting a unit is more cost effective than alternatives, APS will seek ACC approval before moving forward with the Cholla conversion project. APS cannot predict the outcome of this matter.

Four Corners

Ownership and Coal Supply Matters. In 2013, BHP Billiton New Mexico Coal, Inc. ("BHP Billiton"), the parent company of BHP Navajo Coal Company ("BNCC"), the coal supplier and operator of the mine that served Four Corners, transferred its ownership of BNCC to NTEC, a company formed by the Navajo Nation to own the mine and develop other energy projects. At that same time, the Four Corners' co-owners executed the 2016 Coal Supply Agreement for the supply of coal to Four Corners from July 2016 through 2031. El Paso, a 7% owner in Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS agreed to assume the 7% shortfall obligation. On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in each of Units 4 and 5 of Four Corners. 4CA purchased the El Paso interest on July 6, 2016. The purchase price was immaterial in amount, and 4CA assumed El Paso's reclamation and decommissioning obligations associated with the 7% interest.

NTEC had an option to purchase the 4CA 7% interest and ultimately purchased the interest on July 3, 2018. NTEC purchased the 7% interest at 4CA's book value, approximately $70 million, and is paying 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note. In connection with the sale, Pinnacle West guaranteed certain obligations that NTEC will have to the other owners of Four Corners, such as NTEC's 7% share of capital expenditures and operating and maintenance expenses. Pinnacle West's guarantee is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement.

The 2016 Coal Supply Agreement contained alternate pricing terms for the 7% interest in the event NTEC did not purchase the interest. Until the time that NTEC purchased the 7% interest, the alternate pricing provisions were applicable to 4CA, as the holder of the 7% interest. These terms included a formula under which NTEC must make certain payments to 4CA for reimbursement of operations and maintenance costs and a specified rate of return, offset by revenue generated by 4CA's power sales. Such payments are due to 4CA at the end of each calendar year. A $10 million payment was due to 4CA at December 31, 2017, which NTEC satisfied by directing to 4CA a prepayment from APS of a portion of a future mine reclamation obligation. The balance of the amount due under this formula at December 31, 2018 for calendar year 2017 was approximately

$20 million, which was paid to 4CA on December 14, 2018. The balance of the amount under this formula for calendar year 2018 (up to the date that NTEC purchased the 7% interest) is approximately $10 million, which is due to 4CA at December 31, 2019.

Lease Extension. APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also required the approval of the United States Department of the Interior ("DOI"), as did a related federal rights-of-way grant. A federal environmental review was undertaken as part of the DOI review process, and culminated in the issuance by DOI of a record of decision on July 17, 2015 justifying the agency action extending the life of the plant and the adjacent mine.

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

On September 15, 2016, NTEC, the company that owns the adjacent mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. On September 11, 2017, the Arizona District Court issued an order granting NTEC's motion, dismissing the litigation with prejudice, and terminating the proceedings. On November 9, 2017, the environmental group plaintiffs appealed the district court order dismissing their lawsuit. Oral argument for this appeal occurred on March 7, 2019. We cannot predict whether this appeal will be successful and, if it is successful, the outcome of further district court proceedings.

Wastewater Permit. On July 16, 2018, several environmental groups filed a petition for review before the EPA EAB concerning the NPDES wastewater discharge permit for Four Corners, which was reissued on June 12, 2018. The environmental groups allege that the permit was reissued in contravention of several requirements under the Clean Water Act and did not contain required provisions concerning EPA’s 2015 revised effluent limitation guidelines for steam-electric EGUs, 2014 existing-source regulations governing cooling-water intake structures, and effluent limits for surface seepage and subsurface discharges from coal-ash disposal facilities. To address certain of these issues through a reconsidered permit, EPA took action on December 19, 2018 to withdraw the NPDES permit reissued in June 2018. Withdrawal of the permit moots the EAB appeal, and EPA filed a motion to dismiss on that basis. The EAB thereafter dismissed the environmental group appeal on February 12, 2019. EPA indicated that, depending on the extent of public comments it receives concerning the permit proposal, it anticipates taking final action on a new NPDES permit by August 2019. At this time, we cannot predict the outcome of EPA's reconsideration of the NPDES permit and whether reconsideration will have a material impact on our financial position, results of operations or cash flows.

Navajo Plant

The co-owners of the Navajo Plant and the Navajo Nation agreed that the Navajo Plant will remain in operation until December 2019 under the existing plant lease. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017 that will allow for decommissioning activities to begin after the plant ceases operations in December 2019.

APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant over its previously estimated life through 2026. APS will seek continued recovery in rates for the book value of its remaining investment in the plant (see Note 4 for details related to the resulting regulatory asset) plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and may be material.

Natural Gas. APS has six natural gas power plants located throughout Arizona, including Ocotillo. Ocotillo was originally a 330 MW 4-unit gas plant located in the metropolitan Phoenix area. In early 2014, APS announced a project to modernize the plant, which involves retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. In total, this increases the capacity of the site by 290 MW to 620 MW, with completion targeted by the middle of 2019. (See Note 4 for details of the rate recovery in our 2017 Rate Case Decision.)

Transmission and Delivery. APS continues to work closely with customers, stakeholders, and regulators to identify and plan for transmission needs that support new customers, system reliability, access to markets and clean energy development. The capital expenditures table presented in the "Liquidity and Capital Resources" section below includes new APS transmission projects, along with other transmission costs for upgrades and replacements. APS is also working to establish and expand advanced grid technologies throughout its service territory to provide long-term benefits both to APS and its customers. APS is strategically deploying a variety of technologies that are intended to allow customers to better manage their energy usage, minimize system outage durations and frequency, enable customer choice for new customer sited technologies, and facilitate greater cost savings to APS through improved reliability and the automation of certain distribution functions.

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

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

	Net Capacity in Operation (MW)		Net Capacity Planned / Under Development (MW)	
Total APS Owned: Solar	238		—	
Purchased Power Agreements:				
Solar	310		—	
Solar + Energy Storage	—		50	
Wind	289		—	
Geothermal	10		—	
Biomass	14		—	
Biogas	6		—	
Total Purchased Power Agreements	629		50	
Total Distributed Energy: Solar (a)	878		30	(b)
Total Renewable Portfolio	1,745		80	

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

APS has developed and owns solar resources through the ACC-approved AZ Sun Program. APS invested approximately $675 million in the AZ Sun Program.

Energy Storage. APS deploys a number of advanced technologies on its system, including energy storage. Storage can provide capacity, improve power quality, be utilized for system regulation, integrate renewable generation, and can be used to defer certain traditional infrastructure investments. Battery 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 battery storage projects to evaluate the potential benefits for customers and further our understanding of how storage works with other advanced technologies and the grid. We are preparing for additional battery storage in the future.

In early 2018, APS entered into a 15-year power purchase agreement for a 65 MW solar facility that charges a 50 MW solar-fueled battery. Service under this agreement is scheduled to begin in 2021. APS issued a request for proposal for approximately 106 MW of battery storage to be located at up to five of its AZ Sun sites. Based upon our evaluation of the RFP responses, APS decided to expand the initial phase of battery deployment to 141 MW by adding a sixth AZ Sun site. In February 2019, we contracted for the 141 MW and anticipate such facilities could be in service by mid-2020. Additionally, in February 2019, APS signed two 20-year power purchase agreements for energy storage totaling 150 MW. Service under these power purchase agreements are scheduled to begin in 2021, pending approval from the ACC to allow for recovery of these agreements through the PSA. We plan to install at least an additional 660 MW of APS-owned solar plus battery storage and stand-alone battery storage systems by the summer of 2025, with the first 260 MW being procured in 2019 (60 MW on additional AZ Sun sites and 100 MW of solar plus 100 MW of battery storage).

Regulatory Matters

Rate Matters. APS needs timely recovery through rates of its capital and operating expenditures to maintain its financial health. APS's retail rates are regulated by the ACC and its wholesale electric rates (primarily for transmission) are regulated by FERC. See Note 4 for information on APS's FERC rates.

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates. On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, the Residential Utility Consumer Office, limited income advocates and private rooftop solar organizations signed the 2017 Settlement Agreement and filed it with the ACC. 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 4.54%). (See Note 4 for details of the 2017 Settlement Agreement.)

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 Administrative Law Judge to be a complaint filed pursuant to Arizona Revised Statute §40-246 and not a request for rehearing. Arizona Revised Statute §40-246 requires the ACC to hold a hearing regarding any complaint alleging that a public service corporation is in violation of any commission order or that the rates being charged are not just and reasonable if the complaint is signed by at least twenty-five customers of the public service corporation. The Complaint alleged that APS is "in violation of commission order" [sic]. On February 13, 2018, the complainant filed an amended Complaint alleging that the rates and charges in the 2017 Rate Case Decision are not just and reasonable. The complainant requested that the ACC hold a hearing on the amended Complaint to determine if the average bill impact on residential customers of the rates and charges approved in the 2017 Rate Case Decision is greater than 4.54% (the average annual bill impact for a typical APS residential customer estimated by APS) and, if so, what effect the alleged greater bill impact has on APS's revenues and the overall reasonableness and justness of APS's rates and charges, in order to determine if there is sufficient evidence to warrant a full-scale rate hearing. The ACC held a hearing on this matter beginning in September 2018 and the hearing was concluded on October 1, 2018. Post-hearing briefing was concluded on December 14, 2018. On April 9, 2019, the Administrative Law Judge issued a Recommended Opinion and Order recommending that the Complaint be dismissed. On April 22, 2019, the Administrative Law Judge issued a proposed amendment to the Recommended Opinion and Order which proposes that APS credit back to customers the $5 million DSMAC funds used by APS to educate ratepayers on the new rates and that APS ratepayers will be held harmless from expenditures made by APS for targeted outreach and education in any future rate case. APS cannot predict the outcome of this matter.

On December 24, 2018, certain ACC Commissioners filed a letter stating that because the ACC had received a substantial number of complaints that the rate increase authorized by the 2017 Rate Case Decision was much more than anticipated, they believe there is a possibility that APS is earning more than was authorized by the 2017 Rate Case Decision. Accordingly, the ACC Commissioners requested the ACC Staff to perform a rate review of APS using calendar year 2018 as a test year and file a report by May 3, 2019. The ACC Commissioners also asked the ACC Staff to evaluate APS's efforts to educate its customers regarding the new rates approved in the 2017 Rate Case Decision. On January 9, 2019, the ACC Commissioners voted to open a docket for this matter. On April 23, 2019, the ACC Staff indicated that they may need some additional time beyond May 3, 2019 to file the requested report. APS does not believe that the rate review will have a material impact on our current financial position, results of operations or cash flows. However, depending upon the results of the rate review, the ACC may take further actions, including potentially reopening the 2017 Rate Case Decision. APS cannot predict the outcome of this matter.

APS has several recovery mechanisms in place that provide more timely recovery to APS of its fuel and transmission costs, and costs associated with the promotion and implementation of its demand side management and renewable energy efforts and customer programs. These mechanisms, such as the RES and DSMAC, are described more fully in Note 4.

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 rate 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 anticipates a decision later in 2019, however we cannot predict the outcome of the decision. APS may be required to record a charge to its results of operations if the ACC issues an unfavorable decision (see SCR deferral in the Regulatory Assets and Liabilities table in Note 4).

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 TEAM Phase I with the ACC that addressed the change in the marginal federal tax rate from 35% to 21% resulting from the Tax Act and reduces rates by $119.1 million annually through an equal cents per kWh credit. 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 TEAM Phase II, 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. The ACC approved this request on March 13, 2019, effective the first billing cycle in April 2019. The impact of TEAM Phase II is expected to be earnings neutral as 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 addresses the amortization of depreciation related excess deferred taxes over a 28.5 year period ("TEAM Phase III"). Over the first 36 months, TEAM Phase III is expected to return $34.5 million to customers annually, and APS has proposed this refund begin July 1, 2019. The Company is currently in the process of seeking IRS guidance affirming the amortization method and period applicable to these depreciation related excess deferred taxes. The ACC has not yet approved TEAM Phase III.

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

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

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

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

February 13, 2019, Commissioner Burns filed a notice of appeal. APS and Pinnacle West cannot predict the outcome of this matter.

Information Requests from Arizona Corporation Commissioners. On January 14, 2019, ACC Commissioner Kennedy opened a docket to investigate campaign expenditures and political participation of APS and Pinnacle West. In addition, on February 27, 2019, ACC Commissioners Burns and Dunn opened a new docket and requested documents from APS and Pinnacle West related to ACC elections and charitable contributions related to the ACC. On March 1, 2019, ACC Commissioner Kennedy issued a subpoena to APS seeking several categories of information for both Pinnacle West and APS including political contributions, lobbying expenditures, marketing and advertising expenditures, and contributions made to 501(c)(3) and 501(c)(4) entities, for the years 2013-2018. Pinnacle West and APS voluntarily responded to both sets of requests on March 29, 2019. APS received subsequent requests on these matters and continues to respond to such follow-on requests. Pinnacle West and APS cannot predict the outcome of these matters.

Energy Modernization Plan. On January 30, 2018, ACC Commissioner Tobin proposed the Energy Modernization Plan, which consists 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 IRP process. The Energy Modernization Plan includes replacing the current RES standard with a new standard called the CREST, which incorporates the proposals in the Energy Modernization Plan. On July 5, 2018, ACC Commissioner Tobin's office issued a set of draft CREST rules for the ACC's consideration, which proposes an electricity generating portfolio of at least 80% clean energy sources (including nuclear generation) by 2050, a target of 3,000 MW of deployed energy storage by 2030, and a plan to implement a new Energy Efficiency Standard when the current standard sunsets in 2020.

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 Renewable Energy Standard, Electric and Gas Energy Efficiency Standards, Net Metering, Resource Planning, and the Biennial Transmission Assessment, as well as the development of new rules regarding forest bioenergy, electric vehicles, interconnection of distributed generation, baseload security, blockchain technology and other technological developments, retail competition, and other energy-related topics. On April 25, 2019, the ACC Staff issued a set of draft rules in regards to the Energy Modernization Plan and workshops were held on April 29, 2019 regarding these draft rules. On April 26, 2019, Commissioner Dunn issued a proposed set of rules with regards to the Energy Modernization Plan. APS cannot predict the outcome of this matter.

Integrated Resource Planning. ACC rules require utilities to develop fifteen-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. In March of 2018, the ACC reviewed the 2017 IRPs of its jurisdictional utilities and voted to not acknowledge any of the plans. APS does not believe that this lack of acknowledgment will have a material impact on our financial position, results of operations or cash flows. Based on an ACC decision, APS is required to file a Preliminary Resource Plan by April 1, 2019 and its final IRP by April 1, 2020. On February 25, 2019, APS filed a request to extend the deadline to file its Preliminary Integrated Resource Plan from April 1, 2019 to August 1, 2019. On April 24, 2019, the ACC approved this request.

FERC Matter. As part of APS's acquisition of SCE's interest in Four Corners Units 4 and 5, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay

SCE associated with the termination. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS established a regulatory asset of $12 million in 2015 in connection with the payment required under the terms of the Transmission Agreement. On July 1, 2016, FERC issued an order denying APS's request to recover the regulatory asset through its FERC-jurisdictional rates. APS and SCE completed the termination of the Transmission Agreement on July 6, 2016. APS made the required payment to SCE and wrote-off the $12 million regulatory asset and charged operating revenues to reflect the effects of this order in the second quarter of 2016. On July 29, 2016, APS filed for a rehearing with FERC. In its order denying recovery, FERC also referred to its enforcement division a question of whether the agreement between APS and SCE relating to the settlement of obligations under the Transmission Agreement was a jurisdictional contract that should have been filed with FERC. On October 5, 2017, FERC issued an order denying APS's request for rehearing. FERC also upheld its prior determination that the agreement relating to the settlement was a jurisdictional contract and should have been filed with FERC. APS cannot predict whether or if the enforcement division will take any action. APS filed an appeal of FERC's July 1, 2016 and October 5, 2017 orders with the United States Court of Appeals for the Ninth Circuit on December 4, 2017. Oral argument for this proceeding is scheduled for May 15, 2019. APS cannot predict the outcome of the proceeding.

Financial Strength and Flexibility

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

Other Subsidiaries

Bright Canyon Energy. On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE's focus is on new growth opportunities that leverage the Company's core expertise in the electric energy industry. BCE's first initiative is a 50/50 joint venture with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. The joint venture, named TransCanyon, is pursuing independent transmission opportunities within the eleven states that comprise the Western Electricity Coordinating Council, excluding opportunities related to transmission service that would otherwise be provided under the tariffs of the retail service territories of the venture partners' utility affiliates. TransCanyon continues to pursue transmission development opportunities in the western United States consistent with its strategy.

El Dorado. The operations of El Dorado are not expected to have any material impact on our financial results, or to require any material amounts of capital, over the next three years.

4CA. See "Four Corners - Ownership and Coal Supply Matters" above for information regarding 4CA.

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 2016 through 2018, 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 1.9% for the three months ended March 31, 2019 compared with the prior-year period. For the three years 2016 through 2018, APS's customer growth averaged 1.6% per year. We currently project annual customer growth to be 1.5 - 2.5% for 2019 and to average in the range of 1.5 - 2.5% for 2019 through 2021 based on our assessment of improving economic conditions in Arizona.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 1.0% for the three months ended March 31, 2019 compared with the prior-year period. Improving economic conditions and customer growth were offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives. For the three years 2016 through 2018, annual retail electricity sales were about flat, adjusted to exclude the effects of weather variations. We currently project that annual retail electricity sales in kWh will increase in the range of 1.0 - 2.0% for 2019 and increase on average in the range of 1.5 - 2.5% during 2019 through 2021, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. Slower than expected growth of the Arizona economy or acceleration of the expected effects of customer conservation, energy efficiency or distributed renewable generation initiatives could further impact these estimates.

Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as economic conditions, customer growth, usage patterns and energy conservation, impacts of energy efficiency programs and growth in DG, and responses to retail price changes. Based on past experience, a reasonable range of variation in our kWh sales projections attributable to such economic factors under normal business conditions can result in increases or decreases in annual net income of up to approximately $15 million.

Weather. In forecasting the retail sales growth numbers provided above, we assume normal weather patterns based on historical data. Historically, extreme weather variations have resulted in annual variations in net income in excess of $20 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 $10 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 and income tax impacts related to bonus depreciation.

Pension and other postretirement non-service credits - net. Pension and other postretirement non-service credits can be impacted by changes in our actuarial assumptions. The most relevant actuarial assumptions are the discount rate used to measure our net periodic costs/credit, the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term, the mortality assumptions and the assumed healthcare cost trend rates. We review these assumptions on an annual basis and adjust them as necessary.

Property Taxes. Taxes other than income taxes consist primarily of property taxes, which are affected by the value of property in-service and under construction, assessment ratios, and tax rates. The average property tax rate in Arizona for APS, which owns essentially all of our property, was 11.0% of the assessed value for 2018, 11.2% for 2017 and 11.2% for 2016. We expect property taxes to increase as we add new generating units and continue with improvements and expansions to our existing generating units and transmission and distribution facilities.

Income Taxes. Income taxes are affected by the amount of pretax book income, income tax rates, certain deductions and non-taxable items, such as AFUDC. In addition, income taxes may also be affected by the settlement of issues with taxing authorities. On December 22, 2017, the Tax 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 15 for details of the impacts on the Company as of March 31, 2019.) In APS's recent general retail rate case, 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.)

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.

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 electric service to Native Load customers) and related activities and includes electricity generation, transmission and distribution.

Operating Results — Three-month period ended March 31, 2019 compared with three-month period ended March 31, 2018.

Our consolidated net income attributable to common shareholders for the three months ended March 31, 2019 was $18 million, compared with consolidated net income attributable to common shareholders of $3 million for the prior-year period. The results reflect an increase of approximately $13 million for the regulated electricity segment primarily due to the effects of weather, the change in residential rate design and seasonal rates and lower fossil planned outages, partially offset by lower pension and other postretirement non-service credits and higher depreciation and amortization.

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

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 509	$ 489	$ 20
Operations and maintenance	(245)	(260)	15
Depreciation and amortization	(149)	(144)	(5)
Taxes other than income taxes	(55)	(53)	(2)
Pension and other postretirement non-service credits - net	5	13	(8)
All other income and expenses, net	14	15	(1)
Interest charges, net of allowance for borrowed funds used during construction	(54)	(52)	(2)
Income taxes	(2)	2	(4)
Less income related to noncontrolling interests (Note 6)	(5)	(5)	—
Regulated electricity segment income	18	5	13
All other	—	(2)	2
Net Income Attributable to Common Shareholders	$ 18	$ 3	$ 15

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $20 million higher for the three months ended March 31, 2019 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)		
Effects of weather	$ 28	$ 7	$ 21
Change in residential rate design and seasonal rates (a)	13	—	13
Lower transmission revenues (Note 4)	(8)	—	(8)
Refunds due to lower Federal corporate income tax rate (Note 4)	(4)	—	(4)
Lower renewable energy regulatory surcharges and higher purchased power, partially offset by operations and maintenance costs	(5)	1	(6)
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	17	18	(1)
Higher retail revenue due to higher customer growth and changes in customer usage patterns, partially offset by the impacts of energy efficiency and distributed generation	4	2	2
Miscellaneous items, net	4	1	3
Total	$ 49	$ 29	$ 20

(a) As part of the 2017 Settlement Agreement, rate design changes were implemented in the spring of 2018 that moved some revenue responsibility from summer to non-summer months. The change was made to better align revenue collections with costs of service.

Operations and maintenance. Operations and maintenance expenses decreased $15 million for the three months ended March 31, 2019 compared with the prior-year period primarily because of:

- A decrease of $8 million in fossil generation primarily due to lower planned outages; and

- A decrease of $7 million related to costs for renewable energy and similar regulatory programs, which is partially offset by operating revenues and purchased power.

Depreciation and amortization. Depreciation and amortization expenses were $5 million higher for the three months ended March 31, 2019 compared with the prior-year period primarily related to increased plant in service.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $8 million lower for the three months ended March 31, 2019 compared to the prior-year period primarily due to lower market returns.

Income taxes. Income taxes were $4 million higher for the three months ended March 31, 2019 compared with the prior-year period primarily due to higher pretax income, partially offset by the effects of refunds due to lower Federal corporate income tax rate (Note 4).

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

Our primary sources of cash are dividends from APS and external debt and equity issuances. An ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the related ACC order, the common equity ratio is defined as total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At March 31, 2019, APS's common equity ratio, as defined, was 54%. Its total shareholder equity was approximately $5.7 billion, and total capitalization was approximately $10.6 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $4.2 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.

On December 20, 2018, the Joint Committee on Taxation ("JCT") released the general explanation of the Tax Act. The document - commonly referred to as the "Blue Book" - provides a comprehensive technical description of the Tax Act and includes the legislative intent of Congress with respect to the changes made by provisions of the Tax Act. The "Blue Book" provides clarification that the intent of the Tax Act was to exclude from the definition of bonus depreciation qualified property any property placed in service by a regulated public utility after December 31, 2017. As a result, the Company currently does not anticipate recognizing any cash tax benefits related to bonus depreciation for property placed in service on or after January 1, 2018 (See Note 15).

Summary of Cash Flows

The following tables present net cash provided by (used for) operating, investing and financing activities for the three months ended March 31, 2019 and 2018 (dollars in millions):

Pinnacle West Consolidated

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Net Change
Net cash flow provided by operating activities	$ 173	$ 167	$ 6
Net cash flow used for investing activities	(254)	(361)	107
Net cash flow provided by financing activities	81	196	(115)
Net change in cash and cash equivalents	$ —	$ 2	$ (2)

Arizona Public Service Company

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Net Change
Net cash flow provided by operating activities	$ 188	$ 177	$ 11
Net cash flow used for investing activities	(260)	(355)	95
Net cash flow provided by financing activities	72	178	(106)
Net change in cash and cash equivalents	$ —	$ —	$ —

Operating Cash Flows

Three-month period ended March 31, 2019 compared with three-month period ended March 31, 2018. Pinnacle West's consolidated net cash provided by operating activities was $173 million in 2019 and $167 million in 2018, an increase of $6 million in net cash provided by operating activities.

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 110% funded as of January 1, 2019 and 117% as of January 1, 2018. Under GAAP, the qualified pension plan was 90% funded as of January 1, 2019 and 95% funded as of January 1, 2018. 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 made voluntary contributions of $90 million to our pension plan year-to-date in 2019. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to a total of $350 million during the 2019-2021 period. We do not expect to make any contributions over the next three years to our other postretirement benefit plans.

Investing Cash Flows

Three-month period ended March 31, 2019 compared with three-month period ended March 31, 2018. Pinnacle West's consolidated net cash used for investing activities was $254 million in 2019, compared to $361 million in 2018, a decrease of $107 million primarily related to decreased capital expenditures. The difference between APS and Pinnacle West's net cash used for investing activities primarily relates to Pinnacle West's investing cash activity related to 4CA.

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

Capital Expenditures
(dollars in millions)

	Estimated for the Year Ended December 31,		
	2019	**2020**	**2021**
APS			
Generation:			
Clean:			
Nuclear Fuel	$ 71	$ 64	$ 64
Nuclear Generation	70	68	67
Renewables (a)	16	18	3
New Resources (b)	90	182	291
Environmental	31	41	71
New Gas Generation	16	—	—
Other Generation	119	117	105
Distribution	500	455	546
Transmission	199	171	197
Other (c)	125	150	128
Total APS	$ 1,237	$ 1,266	$ 1,472

(a) Primarily APS Solar Communities program
(b) Projected future generation resources, which may include energy storage, renewable projects, and other clean energy 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 projected future new resources. 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 roof top solar systems, new clean resources, and upgrades and capital replacements of various nuclear and fossil power plant equipment, such as turbines, boilers and environmental equipment. We are monitoring the status of environmental matters, which, depending on their final outcome, could require modification to our planned environmental expenditures.

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

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

Financing Cash Flows and Liquidity

Three-month period ended March 31, 2019 compared with three-month period ended March 31, 2018. Pinnacle West's consolidated net cash provided by financing activities was $81 million in 2019, compared to $196 million of net cash provided in 2018, a decrease of $115 million in net cash provided. The decrease in net cash provided by financing activities includes a net decrease in short term borrowings of $107 million and higher long-term debt repayments of $500 million, which was partially offset by $497 million in higher issuances of long-term debt. The difference between APS and Pinnacle West's net cash provided by financing activities primarily relates to short-term borrowings and repayments at Pinnacle West on behalf of 4CA.

Significant Financing Activities. On April 17, 2019, the Pinnacle West Board of Directors declared a dividend of $0.7375 per share of common stock, payable on June 3, 2019 to shareholders of record on May 1, 2019.

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

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

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

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.

At March 31, 2019, Pinnacle West had a 364-day $150 million credit facility that matures June 27, 2019. Borrowings under the facility bear interest at LIBOR plus 0.70% per annum. At March 31, 2019, Pinnacle West had $49 million in outstanding borrowings under the facility.

At March 31, 2019, Pinnacle West had a $200 million facility that matures in July 2023. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on Pinnacle West's senior unsecured debt credit ratings. The facility is available to support Pinnacle West's $200 million commercial paper program, for bank borrowings or for issuances of letters of credits. At March 31, 2019, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and $38 million of commercial paper borrowings.

At March 31, 2019, APS had two revolving credit facilities totaling $1 billion, including a $500 million credit facility that matures in June 2022 and a $500 million facility that matures in July 2023. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings. These facilities are available to support APS's $500 million commercial paper program, for bank borrowings or for issuances of letters of credit. At March 31, 2019, APS had $158 million of commercial paper outstanding and no outstanding borrowings or letters of credit under its revolving credit facilities.

See "Financial Assurances" in Note 8 for a discussion of APS's 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 this covenant. For both Pinnacle West and APS, this covenant requires that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At March 31, 2019, the ratio was approximately 51% for Pinnacle West and 46% 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 November 27, 2018, the ACC issued a financing order that, subject to specified parameters and procedures, increased APS's long-term debt limit from $5.1 billion to $5.9 billion, and authorized APS's short-term debt limit equal to a sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power).

Credit Ratings

The ratings of securities of Pinnacle West and APS as of April 24, 2019 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	Stable	Stable	Stable
APS			
Corporate credit rating	A2	A-	A-
Senior unsecured	A2	A-	A
Commercial paper	P-1	A-2	F2
Outlook	Stable	Stable	Stable

Off-Balance Sheets Arrangements

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

Contractual Obligations

As of March 31, 2019, our fuel and purchased power commitments have increased approximately $180 million from the information provided in our 2018 Form 10-K. This change primarily relates to new purchased power commitments. The majority of the changes relate to 2024 and thereafter.

Other than the item described above, there have been no material changes, as of March 31, 2019, outside the normal course of business in contractual obligations from the information provided in our 2018 Form 10-K. See Note 3 for discussion regarding changes in our long-term debt obligations.

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 2018 Form 10-K. See "Critical Accounting Policies" in Item 7 of the 2018 Form 10-K for further details about our critical accounting policies.

OTHER ACCOUNTING MATTERS

On January 1, 2019 we adopted new lease accounting guidance (ASU 2016-02, and related amendments) (see Note 16). We are currently evaluating the impacts of the pending adoption of the following new accounting standards effective for us on January 1, 2020:

- ASU 2016-13: Financial Instruments, Measurement of Credit Losses
- ASU 2018-15: Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract

See Note 13 for additional information related to new accounting standards.

MARKET AND CREDIT RISKS

Market Risks

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

Interest Rate and Equity Risk

We have exposure to changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and the market value of fixed income securities held by our nuclear decommissioning trust, other special use funds (see Note 11 and Note 12), and benefit plan assets. The nuclear decommissioning trust, other special use funds and benefit plan assets also have risks associated with the changing market value of their equity and other non-fixed income investments. Nuclear decommissioning and benefit plan costs are recovered in regulated electricity prices.

Commodity Price Risk

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

The following table shows the net pretax changes in mark-to-market of our derivative positions for the three months ended March 31, 2019 and 2018 (dollars in millions):

	Three Months Ended March 31,	
	2019	2018
Mark-to-market of net positions at beginning of period	$ (58)	$ (91)
Decrease (Increase) in regulatory asset/liability	12	(21)
Recognized in OCI:		
Mark-to-market losses realized during the period	—	—
Change in valuation techniques	—	—
Mark-to-market of net positions at end of period	$ (46)	$ (112)

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at March 31, 2019 by maturities and by the type of valuation that is performed to calculate the fair values, classified in their entirety based on the lowest level of input that is significant to the fair value measurement. See Note 1, "Derivative Accounting" and "Fair Value Measurements," in Item 8 of our 2018 Form 10-K and Note 11 for more discussion of our valuation methods.

Source of Fair Value	2019	2020	2021	2022	2023	Total fair value
Observable prices provided by other external sources	$ (23)	$ (8)	$ (6)	$ (3)	$ —	$ (40)
Prices based on unobservable inputs	(4)	(2)	—	—	—	(6)
Total by maturity	$ (27)	$ (10)	$ (6)	$ (3)	$ —	$ (46)

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

	March 31, 2019 Gain (Loss)		December 31, 2018 Gain (Loss)	
	Price Up 10%	Price Down 10%	Price Up 10%	Price Down 10%
Mark-to-market changes reported in:				
Regulatory asset (liability) (a)				
Electricity	$ 5	$ (5)	$ 1	$ (1)
Natural gas	45	(45)	44	(44)
Total	$ 50	$ (50)	$ 45	$ (45)

(a) These contracts are economic hedges of our forecasted purchases of natural gas and electricity. The impact of these hypothetical price movements would substantially offset the impact that these same price movements would have on the physical exposures being hedged. To the extent the amounts are eligible for inclusion in the PSA, the amounts are recorded as either a regulatory asset or liability.

Credit Risk

We are exposed to losses in the event of non-performance or non-payment by counterparties. See Note 7 for a discussion of our credit valuation adjustment policy.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Item 4. CONTROLS AND PROCEDURES

(a) Disclosure Controls and Procedures

The term "disclosure controls and procedures" means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act") (15 U.S.C. 78a *et seq*.), is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to a company's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Pinnacle West's management, with the participation of Pinnacle West's Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of Pinnacle West's disclosure controls and procedures as of March 31, 2019. Based on that evaluation, Pinnacle West's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, Pinnacle West's disclosure controls and procedures were effective.

APS's management, with the participation of APS's Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of APS's disclosure controls and procedures as of March 31, 2019. Based on that evaluation, APS's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, APS's disclosure controls and procedures were effective.

(b) Changes in Internal Control Over Financial Reporting

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

No change in Pinnacle West's or APS's internal control over financial reporting occurred during the fiscal quarter ended March 31, 2019 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 2018 Form 10-K with regard to pending or threatened litigation and other disputes.

See Note 4 for ACC and FERC-related matters.

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

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 2018 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 2018 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

None.

Item 6. EXHIBITS

(a) Exhibits

Exhibit No.	Registrant(s)	Description
10.1	Pinnacle West APS	Term Loan Agreement dated as of February 26, 2019 among APS, as Borrower, SunTrust Bank, as Agent, SunTrust Bank, TD Bank, N.A., U.S. Bank National Association and The Bank of Nova Scotia, as Co-Syndication Agents and such institutions compromising the lenders party thereto
10.2	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan
10.3	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan
31.1	Pinnacle West	Certificate of Donald E. Brandt, 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 James R. Hatfield, Executive Vice President and 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 Donald E. Brandt, 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 James R. Hatfield, Executive Vice President and 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

*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 22, 2017	3.1 to Pinnacle West/APS February 28, 2017 Form 8-K Report, File Nos. 1-8962 and 1-4473	2/28/2017
3.2	Pinnacle West	Articles of Incorporation, restated as of May 21, 2008	3.1 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/7/2008
3.3	APS	Articles of Incorporation, restated as of May 25, 1988	4.2 to APS's Form S-3 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report, File No. 1-4473	9/29/1993
3.4	APS	Amendment to the Articles of Incorporation of Arizona Public Service Company, amended May 16, 2012	3.1 to Pinnacle West/APS May 22, 2012 Form 8-K Report, File Nos. 1-8962 and 1-4473	5/22/2012
3.5	APS	Arizona Public Service Company Bylaws, amended as of December 16, 2008	3.4 to Pinnacle West/APS December 31, 2008 Form 10-K, File Nos. 1-8962 and 1-4473	2/20/2009

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

SIGNATURES

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

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Dated: May 1, 2019

By: /s/ James R. Hatfield
James R. Hatfield
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer and
Officer Duly Authorized to sign this Report)

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Dated: May 1, 2019

By: /s/ James R. Hatfield
James R. Hatfield
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer and
Officer Duly Authorized to sign this Report)