PINNACLE WEST CAPITAL CORP
Form 10-Q
May 02, 2018

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, 2018

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 25, 2018: 111,933,168
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of April 25, 2018: 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, 2017 ("2017 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 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 2017 Form 10-K, and in Part II, Item 1A 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,	
	2018	2017
OPERATING REVENUES	$692,714	$677,728
OPERATING EXPENSES		
Fuel and purchased power	197,110	212,395
Operations and maintenance	265,682	226,071
Depreciation and amortization	144,825	127,627
Taxes other than income taxes	53,600	43,836
Other expenses	163	388
Total	661,380	610,317
OPERATING INCOME	31,334	67,411
OTHER INCOME (DEDUCTIONS)		
Allowance for equity funds used during construction	14,079	9,482
Pension and other postretirement non-service credits - net	12,859	6,095
Other income (Note 9)	3,985	480
Other expense (Note 9)	(3,229)	(3,680)
Total	27,694	12,377
INTEREST EXPENSE		
Interest charges	58,954	51,864
Allowance for borrowed funds used during construction	(6,755)	(4,472)
Total	52,199	47,392
INCOME BEFORE INCOME TAXES	6,829	32,396
INCOME TAXES	(1,265)	4,211
NET INCOME	8,094	28,185
Less: Net income attributable to noncontrolling interests (Note 6)	4,873	4,873
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$3,221	$23,312
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	112,017	111,728
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	112,493	112,195
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING		
Net income attributable to common shareholders — basic	$0.03	$0.21
Net income attributable to common shareholders — diluted	$0.03	$0.21

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,	
	2018	2017
NET INCOME	$8,094	$28,185
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Derivative instruments:		
Net unrealized loss, net of tax expense of $96 and $674	(96)	(770)
Reclassification of net realized loss, net of tax expense (benefit) of ($82) and $356	409	1,207
Pension and other postretirement benefits activity, net of tax expense of $443 and $704	900	522
Total other comprehensive income	1,213	959
COMPREHENSIVE INCOME	9,307	29,144
Less: Comprehensive income attributable to noncontrolling interests	4,873	4,873
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$4,434	$24,271

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, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$15,440	$13,892
Customer and other receivables	212,188	305,147
Accrued unbilled revenues	118,989	112,434
Allowance for doubtful accounts	(2,046)	(2,513)
Materials and supplies (at average cost)	257,815	264,012
Fossil fuel (at average cost)	48,062	25,258
Assets from risk management activities (Note 7)	1,994	1,931
Deferred fuel and purchased power regulatory asset (Note 4)	74,585	75,637
Other regulatory assets (Note 4)	178,490	172,451
Other current assets	51,887	48,039
Total current assets	957,404	1,016,288
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Note 12)	861,439	871,000
Other special use funds (Note 12)	217,992	32,542
Other assets	58,177	52,040
Total investments and other assets	1,137,608	955,582
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	17,896,772	17,798,061
Accumulated depreciation and amortization	(6,231,918)	(6,128,535)
Net	11,664,854	11,669,526
Construction work in progress	1,453,610	1,291,498
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	108,678	109,645
Intangible assets, net of accumulated amortization	262,523	257,189
Nuclear fuel, net of accumulated amortization	135,400	117,408
Total property, plant and equipment	13,625,065	13,445,266
DEFERRED DEBITS		
Regulatory assets (Note 4)	1,200,260	1,202,302
Assets for other postretirement benefits (Note 5)	89,378	268,978
Other	138,591	130,666
Total deferred debits	1,428,229	1,601,946
TOTAL ASSETS	$17,148,306	$17,019,082

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, 2018	December 31, 2017
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$205,169	$256,442
Accrued taxes	194,930	148,946
Accrued interest	51,335	56,397
Common dividends payable	—	77,667
Short-term borrowings (Note 3)	369,900	95,400
Current maturities of long-term debt (Note 3)	582,000	82,000
Customer deposits	75,759	70,388
Liabilities from risk management activities (Note 7)	67,743	59,252
Liabilities for asset retirements	6,397	4,745
Regulatory liabilities (Note 4)	136,535	100,086
Other current liabilities	184,623	246,529
Total current liabilities	1,874,391	1,197,852
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 3)	4,290,533	4,789,713
DEFERRED CREDITS AND OTHER		
Deferred income taxes	1,689,601	1,690,805
Regulatory liabilities (Note 4)	2,415,417	2,452,536
Liabilities for asset retirements	677,629	674,784
Liabilities for pension benefits (Note 5)	284,007	327,300
Liabilities from risk management activities (Note 7)	47,626	37,170
Customer advances	109,629	113,996
Coal mine reclamation	231,512	231,597
Deferred investment tax credit	205,428	205,575
Unrecognized tax benefits	13,229	13,115
Other	155,633	148,909
Total deferred credits and other	5,829,711	5,895,787
COMMITMENTS AND CONTINGENCIES (SEE NOTE 8)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 111,961,963 and 111,816,170 issued at respective dates	2,620,261	2,614,805
Treasury stock at cost; 29,097 and 64,463 shares at respective dates	(2,431)	(5,624)
Total common stock	2,617,830	2,609,181
Retained earnings	2,454,268	2,442,511
Accumulated other comprehensive loss	(52,341)	(45,002)
Total shareholders' equity	5,019,757	5,006,690
Noncontrolling interests (Note 6)	133,914	129,040
Total equity	5,153,671	5,135,730
TOTAL LIABILITIES AND EQUITY	$17,148,306	$17,019,082

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

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

	Three Months Ended March 31, 2018		2017	
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 8,094		$ 28,185	
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation and amortization including nuclear fuel	163,566		147,861	
Deferred fuel and purchased power	(18,950	)	(988	)
Deferred fuel and purchased power amortization	20,002		(4,172	)
Allowance for equity funds used during construction	(14,079	)	(9,482	)
Deferred income taxes	(229	)	10,357	
Deferred investment tax credit	(147	)	(344	)
Change in derivative instruments fair value	—		(101	)
Stock compensation	10,537		9,997	
Changes in current assets and liabilities:				
Customer and other receivables	89,518		47,007	
Accrued unbilled revenues	(6,555	)	6,723	
Materials, supplies and fossil fuel	(16,607	)	(667	)
Income tax receivable	—		(5,780	)
Other current assets	(664	)	(17,353	)
Accounts payable	(25,738	)	22,147	
Accrued taxes	45,984		43,706	
Other current liabilities	(12,030	)	(101,801	)
Change in margin and collateral accounts — assets	(396	)	(12	)
Change in margin and collateral accounts —	(1,092	)	—	

liabilities				
Change in other long-term assets	(3,369	)	(36,836	)
Change in other long-term liabilities	(70,973	)	1,604	
Net cash flow provided by operating activities	166,872		140,051	
CASH FLOWS FROM INVESTING ACTIVITIES				
Capital expenditures	(361,037	)	(348,824	)
Contributions in aid of construction	8,569		5,975	
Allowance for borrowed funds used during construction	(6,755	)	(4,472	)
Proceeds from nuclear decommissioning trust sales	130,456		151,126	
Investment in nuclear decommissioning trust	(131,027	)	(151,696	)
Other	(1,299	)	(793	)
Net cash flow used for investing activities	(361,093	)	(348,684	)
CASH FLOWS FROM FINANCING ACTIVITIES				
Issuance of long-term debt	—		255,441	
Short-term borrowing and payments — net	263,500		22,097	
Short-term debt borrowings under revolving credit facility	36,000		8,000	
Short-term debt repayments under revolving credit facility	(25,000	)	—	
Dividends paid on common stock	(75,903	)	(71,177	)
Common stock equity issuance - net of purchases	(2,828	)	(11,580	)
Other	—		(1	)
Net cash flow provided by financing activities	195,769		202,780	
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,548		(5,853	)

CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD		13,892		8,881
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$	15,440	$	3,028

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, 2017	111,392,053	$2,596,030	(55,317)	$(4,133)	$2,255,547	$ (43,822)	$ 132,290	$4,935,912
Net income		—		—	23,312	—	4,873	28,185
Other comprehensive income		—		—	—	959	—	959
Issuance of common stock	194,995	(988)		—	—	—	—	(988)
Purchase of treasury stock (a)		—	(153,470)	(12,141)	—	—	—	(12,141)
Reissuance of treasury stock for stock-based compensation and other		—	179,592	14,004	8	—	1	14,013
Balance, March 31, 2017	111,587,048	$2,595,042	(29,195)	$(2,270)	$2,278,867	$ (42,863)	$ 137,164	$4,965,940
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		—		—	8,552	(8,552)	—	—

(See Note 13)								
Balance, March 31, 2018	111,961,963	$2,620,261	(29,097)	$(2,431)	$2,454,268	$(52,341)	$133,914	$5,153,671

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

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

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

	Three Months Ended March 31,	
	2018	2017
OPERATING REVENUES	$692,006	$677,589
OPERATING EXPENSES		
Fuel and purchased power	202,010	217,104
Operations and maintenance	254,601	219,008
Depreciation and amortization	144,112	127,208
Taxes other than income taxes	53,242	43,564
Other expenses	163	436
Total	654,128	607,320
OPERATING INCOME	37,878	70,269
OTHER INCOME (DEDUCTIONS)		
Allowance for equity funds used during construction	14,079	9,482
Pension and other postretirement non-service credits - net	13,197	6,042
Other income (Note 9)	3,772	342
Other expense (Note 9)	(2,945)	(3,128)
Total	28,103	12,738
INTEREST EXPENSE		
Interest charges	56,158	50,796
Allowance for borrowed funds used during construction	(6,755)	(4,472)
Total	49,403	46,324
INCOME BEFORE INCOME TAXES	16,578	36,683
INCOME TAXES	2,106	8,648
NET INCOME	14,472	28,035
Less: Net income attributable to noncontrolling interests (Note 6)	4,873	4,873
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$9,599	$23,162

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,	
	2018	2017
NET INCOME	$14,472	$28,035
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Derivative instruments:		
Net unrealized loss, net of tax expense $96 and $674	(96)	(770)
Reclassification of net realized loss, net of tax expense (benefit) of ($82) and $356	409	1,207
Pension and other postretirement benefits activity, net of tax expense of $306 and $590	857	611
Total other comprehensive income	1,170	1,048
COMPREHENSIVE INCOME	15,642	29,083
Less: Comprehensive income attributable to noncontrolling interests	4,873	4,873
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$10,769	$24,210

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, 2018	December 31, 2017
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	$17,751,964	$17,654,078
Accumulated depreciation and amortization	(6,144,874)	(6,041,965)
Net	11,607,090	11,612,113
Construction work in progress	1,424,023	1,266,636
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	108,678	109,645
Intangible assets, net of accumulated amortization	262,363	257,028
Nuclear fuel, net of accumulated amortization	135,400	117,408
Total property, plant and equipment	13,537,554	13,362,830
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Note 12)	861,439	871,000
Other special use funds (Note 12)	215,800	30,358
Other assets	41,019	36,796
Total investments and other assets	1,118,258	938,154
CURRENT ASSETS		
Cash and cash equivalents	14,001	13,851
Customer and other receivables	198,703	292,791
Accrued unbilled revenues	118,989	112,434
Allowance for doubtful accounts	(2,046)	(2,513)
Materials and supplies (at average cost)	256,573	262,630
Fossil fuel (at average cost)	48,062	25,258
Assets from risk management activities (Note 7)	1,994	1,931
Deferred fuel and purchased power regulatory asset (Note 4)	74,585	75,637
Other regulatory assets (Note 4)	178,490	172,451
Other current assets	45,477	41,055
Total current assets	934,828	995,525
DEFERRED DEBITS		
Regulatory assets (Note 4)	1,200,260	1,202,302
Assets for other postretirement benefits (Note 5)	85,515	265,139
Other	132,336	129,801
Total deferred debits	1,418,111	1,597,242
TOTAL ASSETS	$17,008,751	$16,893,751

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, 2018	December 31, 2017
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$178,162	$178,162
Additional paid-in capital	2,571,696	2,571,696
Retained earnings	2,548,591	2,533,954
Accumulated other comprehensive loss	(30,851)	(26,983)
Total shareholder equity	5,267,598	5,256,829
Noncontrolling interests (Note 6)	133,914	129,040
Total equity	5,401,512	5,385,869
Long-term debt less current maturities (Note 3)	3,992,207	4,491,292
Total capitalization	9,393,719	9,877,161
CURRENT LIABILITIES		
Short-term borrowings (Note 3)	255,500	—
Current maturities of long-term debt (Note 3)	582,000	82,000
Accounts payable	198,025	247,852
Accrued taxes	211,455	157,349
Accrued interest	48,828	55,533
Common dividends payable	—	77,700
Customer deposits	75,759	70,388
Liabilities from risk management activities (Note 7)	67,743	59,252
Liabilities for asset retirements	5,898	4,192
Regulatory liabilities (Note 4)	136,535	100,086
Other current liabilities	180,005	243,922
Total current liabilities	1,761,748	1,098,274
DEFERRED CREDITS AND OTHER		
Deferred income taxes	1,741,907	1,742,485
Regulatory liabilities (Note 4)	2,415,417	2,452,536
Liabilities for asset retirements	669,247	666,527
Liabilities for pension benefits (Note 5)	263,985	306,542
Liabilities from risk management activities (Note 7)	47,626	37,170
Customer advances	109,629	113,996
Coal mine reclamation	215,615	215,830
Deferred investment tax credit	205,428	205,575
Unrecognized tax benefits	43,990	43,876
Other	140,440	133,779
Total deferred credits and other	5,853,284	5,918,316
COMMITMENTS AND CONTINGENCIES (SEE NOTE 8)		
TOTAL LIABILITIES AND EQUITY	$17,008,751	$16,893,751

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, 2018		2017	
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 14,472		$ 28,035	
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation and amortization including nuclear fuel	162,853		147,443	
Deferred fuel and purchased power	(18,950	)	(988	)
Deferred fuel and purchased power amortization	20,002		(4,172	)
Allowance for equity funds used during construction	(14,079	)	(9,482	)
Deferred income taxes	533		8,899	
Deferred investment tax credit	(147	)	(344	)
Change in derivative instruments fair value	—		(101	)
Changes in current assets and liabilities:				
Customer and other receivables	90,647		60,782	
Accrued unbilled revenues	(6,555	)	6,723	
Materials, supplies and fossil fuel	(16,747	)	(631	)
Other current assets	(1,237	)	(15,007	)
Accounts payable	(24,592	)	22,847	
Accrued taxes	54,106		47,817	
Other current liabilities	(15,771	)	(88,990	)
Change in margin and collateral accounts — assets	(396	)	(12	)
Change in margin and collateral accounts — liabilities	(1,092	)	—	
	4,118		(31,172	)

Change in other long-term assets		
Change in other long-term liabilities	(69,836)	1,888
Net cash flow provided by operating activities	177,329	173,535
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(355,039)	(343,139)
Contributions in aid of construction	8,569	5,975
Allowance for borrowed funds used during construction	(6,755)	(4,472)
Proceeds from nuclear decommissioning trust sales	130,456	151,126
Investment in nuclear decommissioning trust	(131,027)	(151,696)
Other	(1,183)	(774)
Net cash flow used for investing activities	(354,979)	(342,980)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	—	255,441
Short-term borrowings and payments — net	255,500	(19,003)
Short-term debt borrowings under revolving credit facility	25,000	—
Short-term debt repayments under revolving credit facility	(25,000)	—
Dividends paid on common stock	(77,700)	(72,900)
Net cash flow provided by financing activities	177,800	163,538
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	150	(5,907)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	13,851	8,840
	$ 14,001	$ 2,933

CASH AND CASH EQUIVALENTS AT END OF PERIOD				
Supplemental disclosure of cash flow information				
Cash paid during the period for:				
Income taxes, net of refunds	$	—	$	—
Interest, net of amounts capitalized	$	54,873	$	53,129
Significant non-cash investing and financing activities:				
Accrued capital expenditures	$	86,944	$	78,977

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

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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, 2017	71,264,947	$178,162	$2,421,696	$2,331,245	$ (25,423)	$ 132,290	$5,037,970
Net income		—	—	23,162	—	4,873	28,035
Other comprehensive income		—	—	—	1,048	—	1,048
Other		—	—	(2)	—	1	(1)
Balance, March 31, 2017	71,264,947	$178,162	$2,421,696	$2,354,405	$ (24,375)	$ 137,164	$5,067,052
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 (See Note 13)		—	—	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

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

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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"). 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 Nuclear 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 2017 Form 10-K.

These consolidated financial statements and notes have been prepared consistently, with the exception of the reclassification of certain prior year amounts on our Condensed Consolidated Statements of Income and APS's Condensed Consolidated Statements of Income. Beginning in quarter ended March 31, 2018, APS changed the format of presentation of its Condensed Consolidated Statements of Income from a utility ratemaking format to a commercial format. Minor changes were made in the description of certain income statement line items and the amounts presented in the comparable prior period also changed by immaterial amounts due to the change from a utility to a non-utility format and also from the adoption of the new accounting guidance for net periodic pension cost and net periodic postretirement benefit cost. In addition, the prior year amounts were reclassified to conform to the current year presentation for the other special use funds in the investment and other assets section on the Condensed Consolidated Balance Sheets.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Cash Flow Information

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

	Three Months Ended March 31,	
	2018	2017
Cash paid (received) during the period for:		
Income taxes, net of refunds	$—	$(2)
Interest, net of amounts capitalized	56,026	54,280
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$86,991	$79,306

2. Revenue

Adoption of Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers
On January 1, 2018, we adopted new revenue guidance in ASU 2014-09 and related amendments. The new revenue guidance requires entities to recognize revenue when control of the promised good or service is transferred to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. We applied the new guidance using the modified retrospective method applied to contracts which were not completed as of January 1, 2018. The adoption of the new revenue guidance resulted in expanded disclosures, but otherwise did not have a material impact on our financial statements. New revenue disclosures required by the standard are included below. See Note 13 for additional information regarding the new accounting standard.

Revenue Recognition and Sources of Revenue

Our revenues are primarily derived from sales of electricity to our regulated retail customers. Our retail electric services and tariff rates are regulated by the ACC. Revenues related to the sale of electric services are recognized when service is rendered or electricity is delivered to the customer. Electricity sales generally represent a single performance obligation delivered over time. We have elected to apply the invoice practical expedient and, as such, we recognize revenue based on the amount to which we have a right to invoice for services performed.

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

	Three Months Ended March 31, 2018
Retail residential electric service	$316,675
Retail non-residential electric service	343,189

Wholesale energy sales	12,089
Transmission services for others	14,845
Other sources	5,916
Total operating revenues	$692,714

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The billing of regulated retail electricity sales to individual customers is based on data obtained from the customer’s meter. We obtain customers' meter data on a systematic basis throughout the month, and generally bill customers within a month from when service was provided. Customers are generally required to pay for services within 15 days of when the services are billed. We do not assess transactions for significant financing components when the period of time between when the goods or services are transferred to the customer and when the customer pays for those goods or services is less than one year.

Unbilled revenues are estimated by applying an average revenue per kilowatt-hour (“kWh”) to the number of estimated kWhs delivered but not billed by customer class. Historically, differences between the actual and estimated unbilled revenues have been immaterial. We exclude sales tax and franchise fees on electric revenues from both revenue and taxes other than income taxes.

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

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

Revenue Activities

Our revenues 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, 2018 were $683 million.

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, 2018, our revenues that do not qualify as revenue from contracts with customers were $10 million. 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 Sheet as of March 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Pinnacle West

At March 31, 2018, Pinnacle West had a $200 million facility that matures in May 2021. 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. At March 31, 2018, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and $37.4 million of commercial paper borrowings.

At March 31, 2018, Pinnacle West had a $125 million 364-day unsecured revolving credit facility that matures on July 30, 2018. Borrowings under the facility bear interest at LIBOR plus 0.80% per annum. At March 31, 2018, Pinnacle West had $77 million outstanding under the facility.

APS

At March 31, 2018, APS had two revolving credit facilities totaling $1 billion, including a $500 million facility that matures in May 2021 and a $500 million credit facility that matures in June 2022. 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, 2018, APS had $255.5 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, 2018		As of December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$298,326	$293,061	$298,421	$298,608
APS	4,574,207	4,845,665	4,573,292	5,006,348
Total	$4,872,533	$5,138,726	$4,871,713	$5,304,956

Debt Provisions

An existing ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the ACC order, the common equity ratio is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At March 31, 2018, APS was in compliance with this common equity ratio requirement. Its total shareholder equity was approximately $5.3 billion, and total capitalization was approximately $10.0 billion. APS would be prohibited from paying dividends if the payment would reduce its total shareholder equity below approximately $4.0 billion, assuming APS's total capitalization remains the same.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 of $165.9 million. This amount excluded amounts that were then collected on customer bills through adjustor mechanisms. The application requested that some of the balances in these adjustor accounts (aggregating to approximately $267.6 million as of December 31, 2015) be transferred into base rates through the ratemaking process. This transfer would not have had an incremental effect on average customer bills. The average annual customer bill impact of APS's request was an increase of 5.74% (the average annual bill impact for a typical APS residential customer was 7.96%).

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 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;

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

- 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 August 20, 2017, Commissioner Burns filed a special action petition in the Arizona Supreme Court seeking to vacate the ACC's order approving the 2017 Settlement Agreement so that alleged issues of disqualification and bias on the part of the other Commissioners can be fully investigated. APS opposed the petition, and on October 17, 2017, the Arizona Supreme Court declined to accept jurisdiction over Commissioner Burns’ special action petition.

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 has filed a motion to intervene. Mr. Woodward filed his opening brief on March 28, 2018. 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 is requesting 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. In April 2018, the judge set a procedural schedule for this matter and a hearing is scheduled for September 2018. APS cannot predict the outcome of this matter.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Prior Rate Case Filing with the Arizona Corporation Commission

On June 1, 2011, APS filed an application with the ACC for a net retail base rate increase of $95.5 million. On January 6, 2012, APS and other parties to the general retail rate case entered into an agreement (the "2012 Settlement Agreement") detailing the terms upon which the parties agreed to settle the rate case. On May 15, 2012, the ACC approved the 2012 Settlement Agreement without material modifications.

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 2013, the ACC conducted a hearing to consider APS's proposal to establish compliance with distributed energy requirements by tracking and recording distributed energy, rather than acquiring and retiring renewable energy credits. On February 6, 2014, the ACC established a proceeding to modify the renewable energy rules to establish a process for compliance with the renewable energy requirement that is not based solely on the use of renewable energy credits. On September 9, 2014, the ACC authorized a rulemaking process to modify the RES rules. The proposed changes would permit the ACC to find that utilities have complied with the distributed energy requirement in light of all available information. The ACC adopted these changes on December 18, 2014. The revised rules went into effect on April 21, 2015.

In December 2014, the ACC voted that it had no objection to APS implementing an APS-owned rooftop solar research and development program aimed at learning how to efficiently enable the integration of rooftop solar and battery storage with the grid. The first stage of the program, called the "Solar Partner Program," placed 8 megawatts ("MW") of residential rooftop solar on strategically selected distribution feeders in an effort to maximize potential system benefits, as well as made systems available to limited-income customers who could not easily install solar through transactions with third parties. The second stage of the program, which included an additional 2 MW of rooftop solar and energy storage, placed two energy storage systems sized at 2 MW on two different high solar penetration feeders to test various grid-related operation improvements and system interoperability, and was in operation by the end of 2016. The costs for this program have been included in APS's rate base as part of the 2017 Rate Case Decision.

On July 1, 2016, APS filed its 2017 RES Implementation Plan and proposed a budget of approximately $150 million. APS's budget request included additional funding to process the high volume of residential rooftop solar interconnection requests and also requested a permanent waiver of the residential distributed energy requirement for 2017 contained in the RES rules. On April 7, 2017, APS filed an amended 2017 RES Implementation Plan and updated budget request which included the revenue neutral transfer of specific revenue requirements into base rates in accordance with the 2017 Settlement Agreement. On August 15, 2017, the ACC approved the 2017 RES Implementation Plan.

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 requiring APS to spend $10 million -$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. The ACC has not yet ruled on APS's 2018 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 new standard 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 includes replacing the current RES standard with the Energy Modernization Plan. APS cannot predict the outcome of this proceeding.

Demand Side Management Adjustor Charge ("DSMAC"). 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. On March 20, 2015, APS filed an application with the ACC requesting a budget of $68.9 million for 2015 and minor modifications to its DSM portfolio going forward, including for the first time three resource savings projects which reflect energy savings on APS's system. The ACC approved APS's 2015 DSM budget on November 25, 2015. In its decision, the ACC also ruled that verified energy savings from APS's resource savings projects could be counted toward compliance with the Electric Energy Efficiency Standards; however, the ACC ruled that APS was not allowed to count savings from systems savings projects toward determination of the achievement of performance incentives, nor may APS include savings from conservation voltage reduction in the calculation of its Lost Fixed Cost Recovery Mechanism ("LFCR") mechanism.

On June 1, 2016, APS filed its 2017 DSM Plan, in which APS proposed programs and measures that specifically focus on reducing peak demand, shifting load to off-peak periods and educating customers about strategies to manage their energy and demand. The requested budget in the 2017 DSM Plan is $62.6 million. On January 27, 2017, APS filed an updated and modified 2017 DSM Plan that incorporated the proposed Residential Demand Response, Energy Storage and Load Management Program and requested that the budget be increased to $66.6 million. On August 15, 2017, the ACC approved the amended 2017 DSM Plan.

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 reduced 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PSA 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 2018 and 2017 (dollars in thousands):

	Three Months Ended March 31,	
	2018	2017
Beginning balance	$75,637	$12,465
Deferred fuel and purchased power costs — current period	18,950	988
Amounts refunded/(charged) to customers	(20,002)	4,172
Ending balance	$74,585	$17,625

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.

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 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

On January 31, 2017, APS made a filing with FERC to reduce the Post-Employment Benefits Other than Pension expense reflected in its FERC transmission formula rate calculation to recognize certain savings resulting from plan design changes to the other postretirement benefit plans. A transmission customer intervened and protested certain aspects of APS's filing. FERC initiated a proceeding under Section 206 of the Federal Power Act to evaluate the justness and reasonableness of the revised formula rate filing APS proposed. APS entered into a settlement agreement with the intervening transmission customer, which was filed with FERC for approval on September 26, 2017. FERC approved the settlement agreement without modification or condition on December 21, 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 Cuts and Jobs Act of 2017 (the "Tax Act") beginning in its 2018 annual transmission formula rate update filing. These modifications will reduce APS's transmission rates compared to the rate that would have gone into effect absent these changes. This matter is still pending and APS is currently unable to predict the outcome of the proceeding.

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 2016 annual LFCR adjustment on January 15, 2016, requesting an LFCR adjustment of $46.4 million (a $7.9 million annual increase). The ACC approved the 2016 annual LFCR effective beginning in May 2016. APS filed its 2017 LFCR adjustment on January 13, 2017 requesting an LFCR adjustment of $63.7 million (a $17.3 million per year increase over 2016 levels). 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 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). Because the LFCR mechanism has a balancing account that trues up any under or over recoveries, a one or two month delay in implementation does not have an adverse effect on APS.

Tax Expense Adjustor Mechanism ("TEAM") and FERC Tax Filing. 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. 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 requesting that the TEAM be implemented in two steps. The first addresses the change in the marginal federal tax rate from 35% to 21% resulting from the Tax Act and, if approved, would reduce rates by $119.1 million annually through an equal cents per kWh credit. APS asked that this decrease become effective February 1, 2018. On February 22, 2018, the ACC approved the reduction of rates by $119.1 million for the remainder of 2018 through an equal cents per kWh

credit applied to all but a small subset of customers who are taking service under specially-approved tariffs. The rate reduction was effective for the first billing cycle in March 2018.

The amount of the benefit of the lower federal income tax rate is based on our quarterly pre-tax earnings pattern, while the reduction in revenues from lower customer rates through the TEAM is based on a per kWh sales credit which follows our seasonal kWh sales pattern and is not impacted by earnings of the Company.

The second step will address the amortization of excess deferred taxes previously collected from customers. APS is analyzing the final impact of the Tax Act provisions related to deferred taxes and intends to make a second TEAM filing later in 2018.

The TEAM expressly applies to APS's retail rates with the exception noted above. As discussed under "Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters" above, APS made a filing with FERC on March 7, 2018 seeking authorization to provide for the cost reductions resulting from the income tax changes in its wholesale transmission rates.

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 as of APS’s 2017 Rate Case Decision, the current net metering tariff that governs payments for energy exported to the grid from rooftop solar systems was replaced by a more formula-driven approach that utilizes inputs from historical wholesale solar power costs and eventually an avoided cost methodology.

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 price that APS pays for utility-scale solar projects on a five year rolling average, 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 August 19, 2017, the date new rates were effective 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
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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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 August 19, 2017.

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 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 complaint. On February 15, 2018, the Superior Court dismissed Commissioner Burns' complaint. On March 6, 2018, Burns filed an objection to the proposed final order from the Superior Court and a motion to amend his complaint. This motion has been fully briefed and the parties are awaiting a decision from the Superior Court judge. The matter is subject to appeal. APS and Pinnacle West cannot predict the outcome of this matter.

In addition to the Superior Court proceedings discussed above, on August 20, 2017, Commissioner Burns filed a special action petition in the Arizona Supreme Court seeking to vacate the 2017 Rate Case Decision so that alleged issues of disqualification and bias on the part of the other Commissioners could be fully investigated. APS opposed the petition, and on October 17, 2017, the Arizona Supreme Court declined to accept jurisdiction over Commissioner Burns' special action petition.

Renewable Energy Ballot Initiative

On February 20, 2018, a coalition of renewable energy advocates filed with the Arizona Secretary of State a ballot initiative for an Arizona constitutional amendment requiring Arizona public service corporations to procure 50% of their energy supply from renewable sources by 2030. For purposes of the proposed amendment, eligible renewable sources would not include nuclear generating facilities. The stated goal of the Clean Energy for a Healthy Arizona coalition is to complete the necessary steps to allow the initiative to be placed on the November 2018 Arizona elections ballot. The coalition must present over 225,000 verifiable signatures to the Secretary of State by July 5, 2018 to meet that goal. APS opposes this effort. APS believes the initiative is irresponsible and would result in negative impacts to Arizona utility customers, the Arizona economy and our company. In April 2018, Arizona passed a law limiting penalties associated with violating this proposed constitutional amendment to no more than $5,000 per violation. APS cannot predict the outcome of this matter.

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 the Energy Modernization Plan. The ACC has not yet initiated any formal proceedings with respect to Commissioner Tobin's proposal; however, on February 22, 2018, the ACC Staff filed a Notice of Inquiry to further examine the matter. As a part of this proposal, the ACC voted in March 2018 to direct utilities to develop a comprehensive biomass generation plan to be included in each utility's RES Implementation 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. IRPs are filed with the ACC every even year, and are reviewed by ACC Staff to assess the adequacy of the plans. The ACC then determines if the IRP meets the requirements of the rule and, if so, acknowledges the IRP. In March of 2018, the ACC reviewed the 2017 IRPs of its jurisdictional utilities and voted to not acknowledge any plan. APS does not believe that this lack of acknowledgment will have a material impact on our financial position, results of operations or cash flows. APS's next IRP will be filed in 2020.

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 $54 million as of March 31, 2018 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. That proceeding is pending, and 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 Rate Rider to permit recovery of costs associated with the installation of SCR equipment at Four Corners Units 4 and 5. APS filed the SCR Rate Rider in April 2018. Consistent with the 2017 Rate Case Decision, the rate rider filing will be narrow in scope and will address only costs associated with this specific environmental compliance equipment. Also, as provided for in the 2017 Rate Case Decision, APS will request that the rate rider become effective no later than January 1, 2019.

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 ($101 million as of March 31, 2018), 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.

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. Various stakeholders including regulators, tribal representatives, the plant's coal supplier and the U.S. Department of the Interior ("DOI") have been meeting to determine if an alternate solution can be reached that would permit continued operation of the plant beyond 2019. Although we cannot predict whether any alternate plans will be found that would be acceptable to all of the stakeholders and feasible to implement, we believe it is probable that the Navajo Plant will cease 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 ($95 million as of March 31, 2018) 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Regulatory Assets and Liabilities

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

	Amortization Through	March 31, 2018		December 31, 2017	
		Current	Non-Current	Current	Non-Current
Pension	(a)	$—	$ 569,784	$—	$ 576,188
Retired power plant costs	2033	26,668	180,298	27,402	188,843
Income taxes — allowance for funds used during construction ("AFUDC") equity	2048	3,818	143,619	3,828	142,852
Deferred fuel and purchased power — mark-to-market (Note 7)	2021	62,069	45,788	52,100	34,845
Deferred fuel and purchased power (b) (d)	2019	74,585	—	75,637	—
Four Corners cost deferral	2024	8,077	46,285	8,077	48,305
Income taxes — investment tax credit basis adjustment	2046	1,066	26,198	1,066	26,218
Lost fixed cost recovery (b)	2019	54,384	—	59,844	—
Palo Verde VIEs (Note 6)	2046	—	19,550	—	19,395
Deferred compensation	2036	—	37,650	—	36,413
Deferred property taxes	2027	8,569	73,244	8,569	74,926
Loss on reacquired debt	2038	1,637	14,896	1,637	15,305
Tax expense of Medicare subsidy	2024	1,235	7,387	1,236	7,415
Transmission cost adjustor (b)	2019	6,867	—	1,220	—
AG-1 deferral	2022	2,654	7,809	2,654	8,472
Mead-Phoenix transmission line CIAC	2050	332	10,293	332	10,376
Coal reclamation	2026	1,068	12,468	1,068	12,396
Other	Various	46	4,991	3,418	353
Total regulatory assets (c)		$253,075	$ 1,200,260	$248,088	$ 1,202,302

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

(b) See "Cost Recovery Mechanisms" discussion above.

(c) 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."

(d) Subject to a carrying charge.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	Amortization Through	March 31, 2018		December 31, 2017	
		Current	Non-Current	Current	Non-Current
Excess deferred income taxes - Tax Cuts and Jobs Act	(a)	$—	$ 1,519,224	$—	$ 1,520,274
Asset retirement obligations	2057	—	315,922	—	332,171
Removal costs	(b)	26,949	197,274	18,238	209,191
Other postretirement benefits	(d)	37,642	142,560	37,642	151,985
Income taxes — deferred investment tax credit	2046	2,144	52,478	2,164	52,497
Income taxes — change in rates	2046	2,799	73,703	2,573	70,537
Spent nuclear fuel	2027	6,609	61,736	6,924	62,132
Renewable energy standard (c)	2019	32,694	—	23,155	—
Demand side management (c)	2019	4,049	4,123	3,066	4,921
Sundance maintenance	2030	—	17,299	—	16,897
Deferred gains on utility property	2022	4,423	9,873	4,423	10,988
Four Corners coal reclamation	2038	1,858	18,525	1,858	18,921
Tax expense adjustor mechanism (c)	2018	15,676	—	—	—
Other	Various	1,692	2,700	43	2,022
Total regulatory liabilities		$136,535	$ 2,415,417	$100,086	$ 2,452,536

(a) While the majority of the excess deferred tax balance shown is subject to special amortization rules under federal income tax laws, which require amortization of the balance over the remaining regulatory life of the related property, treatment of a portion of the liability, and the month in which pass-through of the excess deferred tax balance will begin is subject to regulatory approval. This approval will be sought through the Company's TEAM adjustor mechanism and FERC filings in 2018. As a result, the Company cannot estimate the amount of this regulatory liability which is expected to reverse within the next 12 months. See Note 15.

(b) In accordance with regulatory accounting guidance, APS accrues for removal costs for its regulated assets, even if there is no legal obligation for removal.

(c) See “Cost Recovery Mechanisms” discussion above.

(d) 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. Because of plan changes in September 2014, the Company sought IRS approval to move approximately $186 million of other postretirement benefit trust assets into a new trust account to pay for active union employee medical costs. In December 2016, FERC approved a methodology for determining the amount of other postretirement benefit trust assets to transfer into a new trust account to pay for active union employee medical costs. On January 2, 2018, these funds were moved to the new trust account which is

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included in the other special use funds on the Condensed Consolidated Balance Sheets. The Company negotiated a draft Closing Agreement granting tentative approval from the IRS prior to the transfer. Subsequent to the transfer, the Company submitted proof of the transfer to the IRS. The Company and the IRS executed a final Closing Agreement on March 2, 2018. Per the terms of an order from FERC, the Company must also make an informational filing with FERC. The Company made this FERC filing during February 2018. It is the Company's understanding that completion of these regulatory requirements permits access to approximately $186 million for the sole purpose of paying active union employee medical benefits.

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 Three Months Ended March 31,		Other Benefits Three Months Ended March 31,	
	2018	2017	2018	2017
Service cost — benefits earned during the period	$14,213	$13,760	$5,105	$4,358
Non-service costs (credits):				
Interest cost on benefit obligation	31,007	32,701	7,101	7,565
Expected return on plan assets	(45,667)	(43,710)	(10,520)	(13,350)
Amortization of:				
Prior service cost (credit)	—	20	(9,461)	(9,461)
Net actuarial loss	7,782	12,489	—	1,454
Net periodic benefit cost (credit)	$7,335	$15,260	$(7,775)	$(9,434)
Portion of cost (credit) charged to expense	$2,242	$7,568	$(5,605)	$(4,678)

On January 1, 2018, we adopted new accounting standard ASU 2017-07, Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. This new standard changed our income statement presentation of net periodic benefit cost/(credits) and allows only the service cost component of net periodic benefit cost to be eligible for capitalization. See Note 13 for additional information.

Contributions

We have made voluntary contributions of $50 million to our pension plan year-to-date in 2018. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to a total of $250 million during the 2018-2020 period. We do not expect to make any contributions over the next three years to our other postretirement benefit plans. Year to date in 2018, the Company was reimbursed $22 million for prior year retiree medical claims from the other postretirement benefit plan trust assets.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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, 2018 and 2017 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, 2018 and December 31, 2017 include the following amounts relating to the VIEs (dollars in thousands):

	March 31, 2018	December 31, 2017
Palo Verde sale leaseback property plant and equipment, net of accumulated depreciation	$ 108,678	$ 109,645
Equity — Noncontrolling interests	133,914	129,040

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 $295 million beginning in 2018, and up to $456 million over the lease terms.

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

7. Derivative Accounting

Derivative financial instruments are used to manage exposure to commodity price and transportation costs of electricity, natural gas, coal and 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 sheet 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, 2018 and December 31, 2017, we had the following outstanding gross notional volume of derivatives, which represent both purchases and sales (does not reflect net position):

Commodity	Unit of Measure	Quantity March 31, 2018	Quantity December 31, 2017
Power	GWh	1,277	583
Gas	Billion cubic feet	252	240

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Gains and Losses from Derivative Instruments

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

	Financial Statement Location	Three Months Ended March 31,	
Commodity Contracts		2018	2017
Loss Recognized in OCI on Derivative Instruments (Effective Portion)	OCI — derivative instruments	$ —	$ (96)
Loss Reclassified from Accumulated OCI into Income (Effective Portion Realized) (a)	Fuel and purchased power (b)	(491)	(851)

(a) During the three months ended March 31, 2018 and 2017, we had no gains or losses reclassified from accumulated OCI to earnings due to the discontinuance of cash flow hedges where the forecasted transaction is not probable of occurring.
(b) Amounts are before the effect of PSA deferrals.

During the next twelve months, we estimate that a net loss of $2 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, 2018 and 2017 (dollars in thousands):

	Financial Statement Location	Three Months Ended March 31,	
Commodity Contracts		2018	2017
Net Loss Recognized in Income	Operating revenues	$ (1,219)	$ (288)
Net Loss Recognized in Income	Fuel and purchased power (a)	(34,089)	(52,627)
Total		$ (35,308)	$ (52,915)

(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

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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, 2018 and December 31, 2017. 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, 2018: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$ 5,984	$ (4,686)	$ 1,298	$ 696	$ 1,994
Investments and other assets	819	(819)	—	—	—
Total assets	6,803	(5,505)	1,298	696	1,994
Current liabilities	(69,999)	4,686	(65,313)	(2,430)	(67,743)
Deferred credits and other	(48,445)	819	(47,626)	—	(47,626)
Total liabilities	(118,444)	5,505	(112,939)	(2,430)	(115,369)
Total	$ (111,641)	$ —	$ (111,641)	$ (1,734)	$ (113,375)

(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 are 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. Amounts include cash collateral received from counterparties of $2,430 and cash margin provided to counterparties of $696.

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As of December 31, 2017: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$ 5,427	$ (3,796)	$ 1,631	$ 300	$ 1,931
Investments and other assets	1,292	(1,241)	51	—	51
Total assets	6,719	(5,037)	1,682	300	1,982
Current liabilities	(59,527)	3,796	(55,731)	(3,521)	(59,252)
Deferred credits and other	(38,411)	1,241	(37,170)	—	(37,170)
Total liabilities	(97,938)	5,037	(92,901)	(3,521)	(96,422)
Total	$ (91,219)	$—	$ (91,219)	$ (3,221)	$ (94,440)

(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. Amounts include cash collateral received from counterparties of $3,521 and cash margin provided to counterparties of $300.

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, 2018, 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).

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table provides information about our derivative instruments that have credit-risk-related contingent features at March 31, 2018 (dollars in thousands):

	March 31, 2018
Aggregate fair value of derivative instruments in a net liability position	$118,444
Cash collateral posted	—
Additional cash collateral in the event credit-risk-related contingent features were fully triggered (a)	111,223

(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 $94 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 three claims pursuant to the terms of the August 18, 2014 settlement agreement, for three separate time periods during July 1, 2011 through June 30, 2016. The DOE has approved and paid $65.2 million for these claims (APS's share is $19 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's next claim pursuant to the terms of the August 18, 2014 settlement agreement was submitted to the DOE in the fourth quarter of 2017 in the amount of $9 million (APS's share is $2.6 million). In February 2018, the DOE approved this claim, and in March 2018, the DOE paid this claim. The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income.

Nuclear Insurance

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act ("Price-Anderson Act"), which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry-wide retrospective payment plan. In accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident up to approximately $13.2 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 $12.7 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 $127.3 million, subject to a maximum annual premium of $19 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 $111.1 million, with a maximum annual retrospective premium of approximately $16.6 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

There have been no material changes, as of March 31, 2018, outside the normal course of business in contractual obligations from the information provided in our 2017 Form 10-K. See Note 3 for discussion regarding changes in our long-term debt obligations.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 generated, transported or disposed of hazardous substances at a contaminated site are among those who are potentially responsible parties ("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, APS anticipates finalizing the RI/FS in the spring 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, the Roosevelt Irrigation District ("RID") filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID's groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS's current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, the Arizona Department of Environmental Quality ("ADEQ") sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. On December 16, 2016, two RID contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another party filed an ancillary 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 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 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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 has 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. 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") has the option to purchase the interest within a certain timeframe pursuant to an option granted to NTEC. In December 2015, NTEC notified APS of its intent to exercise the option. The purchase did not occur during the originally contemplated timeframe. See "Four Corners Coal Supply Agreement - 4CA Matter" below for a discussion of the current status of the NTEC purchase. The cost of the pollution controls related to the 7% interest is approximately $45 million, which will be assumed by the ultimate owner 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. 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 current BART requirements for NOx imposed on the Cholla units under EPA's BART FIP.

On October 16, 2015, ADEQ issued a revised operating permit for Cholla, which incorporates APS's proposal, and subsequently submitted a proposed revision to the SIP to EPA, which would incorporate the new permit terms. On June 30, 2016, EPA issued a proposed rule approving a revision to the Arizona SIP that incorporates APS's compromise approach for compliance with the Regional Haze program. 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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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.
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 March 1, 2018, EPA issued a proposed rule that, among other things, seeks comment on potential changes to the federal CCR regulations, including allowances for greater flexibility in setting groundwater protection standards for certain regulated CCR constituents and with respect to implementing corrective action. Given the current proposal stage of this rulemaking, it is not yet clear 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, within the next 2 years EPA is required to complete a rulemaking proceeding 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $22 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $20 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. If this assessment monitoring program reveals concentrations of certain constituents above the CCR rule standards that trigger remedial obligations, a corrective measures evaluation must be completed by January 2019. Depending upon the results of such groundwater monitoring and data evaluations at each of Cholla, Four Corners and the Navajo Plant, we may be required to take corrective actions, the costs of which we are unable to reasonably estimate at this time.

Clean Power Plan. On August 3, 2015, EPA finalized carbon pollution standards for EGUs. Shortly thereafter, a coalition of states, industry groups and electric utilities challenged the legality of these standards, including EPA's Clean Power Plan for existing EGUs, in the U.S. Court of Appeals for the D.C. Circuit. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations under the Clean Power Plan. On March 28, 2017, President Trump issued an Executive Order that, among other things, instructs EPA to reevaluate Agency regulations concerning carbon emissions from EGUs and take appropriate action to suspend, revise or rescind the August 2015 carbon pollution standards for EGUs, including the Clean Power Plan. Also on March 28, 2017, the U.S. Department of Justice, on behalf of EPA, filed a motion with the U.S. Court of Appeals for the D.C. Circuit Court to hold the ongoing litigation over the Clean Power Plan in abeyance pending EPA action in accordance with the Executive Order. At this time, the D.C. Circuit Court proceedings evaluating the legality of the Clean Power Plan remain on hold.

Based upon EPA's reevaluation of the August 2015 carbon pollution standards and the legal basis for these regulations, on October 10, 2017, EPA issued a proposal to repeal the Clean Power Plan. That proposal relies on EPA's current view as to the Agency's legal authority under Clean Air Act Section 111(d), which (in contrast to the Clean Power Plan) would limit the scope of any future Section 111(d) regulations to measures undertaken exclusively at a power plant's source of greenhouse gas ("GHG") emissions. On December 18, 2017, EPA issued an Advanced Notice of Proposed Rulemaking through which EPA is soliciting comments as to potential replacements for the Clean Power Plan that would be consistent with EPA's current legal interpretation of the Clean Air Act.

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 develop regulations replacing the Clean Power Plan. 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.

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. We cannot predict whether this appeal will be successful and, if it is successful, the outcome of further district court proceedings.

Four Corners Coal Supply Agreement

Arbitration

On June 13, 2017, APS received a Demand for Arbitration from NTEC in connection with the 2016 Coal Supply Agreement, dated December 30, 2013, under which NTEC supplies coal to APS and the other Four Corners owners (collectively, the “Buyer”) for use at the Four Corners Power Plant. NTEC was originally seeking a declaratory judgment to support its interpretation of a provision regarding uncontrollable forces in the agreement that relates to annual minimum quantities of coal to be purchased by the Buyer. NTEC also alleged a shortfall in the Buyer’s purchases for the initial contract year of approximately $30 million. APS’s share of this amount is approximately $17 million. On September 20, 2017, NTEC amended its Demand for Arbitration, removing its request for a declaratory judgment and at such time was only seeking relief for the alleged shortfall in the Buyer's purchases for the initial contract year.

The parties have reached an agreement in principle to settle the dispute for $45 million, which includes settlement for the initial contract year and the current contract year. APS’s share of this amount is approximately $34 million. The parties are in discussions to memorialize the settlement terms and finalize amendments to the 2016 Coal Supply Agreement, including modifications to the provisions that gave rise to this dispute. (See “4CA Matter” below for additional matters agreed to between 4CA and NTEC in the settlement arrangement.) The settlement is subject to finalization of related agreements and certain approvals, which are anticipated to be completed by mid-2018, and which should not have a material impact on our financial position, results of operations or cash flows.

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Coal Advance Purchase

As part of the on-going discussions between the parties, on March 12, 2018, APS paid to NTEC approximately $24 million as an advance payment for APS's share of coal under the 2016 CSA. The coal inventory purchased represents an amount that APS expects to use for its plant operations within the next year.

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 in principle 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, to occur on or around July 1, 2018, subject to finalizing related documentation and certain approvals. Under the settlement in principle, NTEC will purchase the 7% interest at 4CA's book value and will pay 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note.

The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% interest in the event NTEC does not purchase the interest. At this time, since NTEC has not yet purchased the 7% interest, the alternate pricing provisions are applicable to 4CA as the holder of the 7% interest. These terms include 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 at March 31, 2018 for the calendar year 2017 is approximately $20 million, which is due to 4CA at December 31, 2018. In future years there may be similar payments due from NTEC to 4CA under this formula; however these payments will cease to accrue once NTEC becomes the owner of the 7% as discussed above.

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, 2018, standby letters of credit totaled $5 million and will expire in 2018. As of March 31, 2018, surety bonds expiring through 2019 totaled $36 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Pinnacle West has issued parental guarantees and has provided indemnification under certain surety bonds for APS which were not material at March 31, 2018. Since July 6, 2016, Pinnacle West has issued four parental guarantees for 4CA relating to payment obligations arising from 4CA's acquisition of El Paso's 7% interest in Four Corners, and pursuant to the Four Corners participation agreement payment obligations arising from 4CA's ownership interest in Four Corners.

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, 2018 and 2017 (dollars in thousands):

	Three Months Ended March 31, 2018	2017
Other income:		
Interest income	$1,891	$477
Debt return on Four Corners SCR deferral (Note 4)	2,092	—
Miscellaneous	2	3
Total other income	$3,985	$480
Other expense:		
Non-operating costs	$(1,646)	$(1,959)
Investment losses — net	(176)	(301)
Miscellaneous	(1,407)	(1,420)
Total other expense	$(3,229)	$(3,680)

The following table provides detail of APS's other income and other expense for the three months ended March 31, 2018 and 2017 (dollars in thousands):

	Three Months Ended March 31, 2018	2017
Other income:		
Interest income	$1,678	$338
Debt return on Four Corners SCR deferral (Note 4)	2,092	—
Miscellaneous	2	4
Total other income	$3,772	$342
Other expense:		
Non-operating costs	$(1,539)	$(1,752)
Miscellaneous	(1,406)	(1,376)
Total other expense	$(2,945)	$(3,128)

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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, 2018 and 2017 (in thousands, except per share amounts):

	Three Months Ended March 31,	
	2018	2017
Net income attributable to common shareholders	$3,221	$23,312
Weighted average common shares outstanding — basic	112,017	111,728
Net effect of dilutive securities:		
Contingently issuable performance shares and restricted stock units	476	467
Weighted average common shares outstanding — diluted	112,493	112,195
Earnings per weighted-average common share outstanding		
Net income attributable to common shareholders — basic	$0.03	$0.21
Net income attributable to common shareholders — diluted	$0.03	$0.21

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 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 in the 2017 Form 10-K for fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

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

Risk Management Activities — Derivative Instruments

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

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

When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3. 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Fair Value Tables

The following table presents the fair value at March 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 March 31, 2018
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 5,255	$ 1,548	$ (4,809)	(b)	$ 1,994
Nuclear decommissioning trust:						
Equity securities	6,575	—	—	(67)	(c)	6,508
U.S. commingled equity funds	—	—	—	413,690	(d)	413,690
U.S. Treasury debt	128,396	—	—	—		128,396
Corporate debt	—	111,735	—	—		111,735
Mortgage-backed debt securities	—	108,951	—	—		108,951
Municipal bonds	—	80,604	—	—		80,604
Other fixed income	—	11,555	—	—		11,555
Subtotal nuclear decommissioning trust	134,971	312,845	—	413,623		861,439
Other special use funds:						
U.S. Treasury debt	174,111	—	—	—		174,111
Municipal bonds	—	27,436	—	—		27,436
Equity securities	14,963	—	—	1,482	(c)	16,445
Subtotal other special use funds	189,074	27,436	—	1,482		217,992
Total Assets	$ 324,045	$ 345,536	$ 1,548	$ 410,296		$ 1,081,425
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (97,142)	$ (21,302)	$ 3,075	(b)	$ (115,369)

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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value at December 31, 2017 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, 2017
Assets						
Cash equivalents	$ 10,630	$—	$ —	$—		$ 10,630
Risk management activities — derivative instruments:						
Commodity contracts	—	5,683	1,036	(4,737)	(b)	1,982
Nuclear decommissioning trust:						
Cash and cash equivalents	7,224	—	—	109	(d)	7,333
U.S. commingled equity funds	—	—	—	417,390	(e)	417,390
U.S. Treasury debt	127,662	—	—	—		127,662
Corporate debt	—	114,007	—	—		114,007
Mortgage-backed debt securities	—	111,874	—	—		111,874
Municipal bonds	—	79,049	—	—		79,049
Other fixed income	—	13,685	—	—		13,685
Subtotal nuclear decommissioning trust	134,886	318,615	—	417,499		871,000
Other special use funds (c):	455	31,562	—	525		32,542
Total Assets	$ 145,971	$ 355,860	$ 1,036	$ 413,287		$ 916,154
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (78,646)	$ (19,292)	$ 1,516	(b)	$ (96,422)

(a) Primarily consists of long-dated electricity contracts.
(b) Represents counterparty netting, margin, and collateral. See Note 7.
(c) Primarily consists of fixed income municipal bonds. Presented as coal reclamation escrow in 2017.
(d) Represents nuclear decommissioning trust net pending securities sales and purchases.
(e) 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).

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

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

The following tables provide information regarding our significant unobservable inputs used to value our risk management derivative Level 3 instruments at March 31, 2018 and December 31, 2017