PINNACLE WEST CAPITAL CORP
Form 10-Q
November 08, 2018

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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 September 30, 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 November 1, 2018: 112,079,739
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of November 1, 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, in Part II, Item 1A of this report, and in Part I, Item 2 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" of this report, which readers should review carefully before placing any reliance on our financial statements or disclosures. Neither Pinnacle West nor APS assumes any obligation to update these statements, even if our internal estimates change, except as required by law.

PART I — FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

INDEX TO FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
OPERATING REVENUES (NOTE 2)	$1,268,034	$1,183,322	$2,934,871	$2,805,637
OPERATING EXPENSES				
Fuel and purchased power	389,936	310,469	844,133	777,475
Operations and maintenance	246,545	230,839	780,624	677,895
Depreciation and amortization	145,971	133,912	436,232	387,278
Taxes other than income taxes	51,375	45,169	158,582	133,294
Other expenses	900	3,385	8,497	5,479
Total	834,727	723,774	2,228,068	1,981,421
OPERATING INCOME	433,307	459,548	706,803	824,216
OTHER INCOME (DEDUCTIONS)				
Allowance for equity funds used during construction	12,259	12,728	39,411	32,666
Pension and other postretirement non-service credits - net	12,449	6,534	37,314	19,601
Other income (Note 9)	6,958	1,091	17,541	2,055
Other expense (Note 9)	(5,063)	(4,993)	(12,063)	(12,495)
Total	26,603	15,360	82,203	41,827
INTEREST EXPENSE				
Interest charges	61,605	55,644	181,267	162,477
Allowance for borrowed funds used during construction	(5,913)	(6,000)	(18,959)	(15,378)
Total	55,692	49,644	162,308	147,099
INCOME BEFORE INCOME TAXES	404,218	425,264	626,698	718,944
INCOME TAXES	84,333	144,319	127,107	237,497
NET INCOME	319,885	280,945	499,591	481,447
Less: Net income attributable to noncontrolling interests (Note 6)	4,873	4,873	14,620	14,620
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$315,012	$276,072	$484,971	$466,827
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	112,148	111,835	112,094	111,787
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	112,533	112,401	112,499	112,314
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING				
Net income attributable to common shareholders — basic	$2.81	$2.47	$4.33	$4.18
Net income attributable to common shareholders — diluted	$2.80	$2.46	$4.31	$4.16

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 September 30,		Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
NET INCOME	$319,885	$280,945	$499,591	$481,447
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Derivative instruments:				
Net unrealized gain (loss), net of tax expense of $0, $5, $96 and $684 for the respective periods	—	9	(96)	(754)
Reclassification of net realized loss, net of tax benefit of $149, $438, $381 and $430 for the respective periods	451	710	1,316	2,480
Pension and other postretirement benefits activity, net of tax expense (benefit) of $361, $487, ($754) and $369 for the respective periods	1,099	790	(2,740)	(21)
Total other comprehensive income	1,550	1,509	(1,520)	1,705
COMPREHENSIVE INCOME	321,435	282,454	498,071	483,152
Less: Comprehensive income attributable to noncontrolling interests	4,873	4,873	14,620	14,620
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$316,562	$277,581	$483,451	$468,532

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

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

	September 30, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$64,991	$13,892
Customer and other receivables	370,714	305,147
Accrued unbilled revenues	196,373	112,434
Allowance for doubtful accounts	(5,215)	(2,513)
Materials and supplies (at average cost)	268,184	264,012
Fossil fuel (at average cost)	40,398	25,258
Assets from risk management activities (Note 7)	1,224	1,931
Deferred fuel and purchased power regulatory asset (Note 4)	65,726	75,637
Other regulatory assets (Note 4)	143,849	172,451
Other current assets	60,946	48,039
Total current assets	1,207,190	1,016,288
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Note 12)	906,687	871,000
Other special use funds (Note 12)	233,740	32,542
Other assets	106,988	52,040
Total investments and other assets	1,247,415	955,582
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	18,443,985	17,798,061
Accumulated depreciation and amortization	(6,328,751)	(6,128,535)
Net	12,115,234	11,669,526
Construction work in progress	1,200,625	1,291,498
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	106,743	109,645
Intangible assets, net of accumulated amortization	268,630	257,189
Nuclear fuel, net of accumulated amortization	134,812	117,408
Total property, plant and equipment	13,826,044	13,445,266
DEFERRED DEBITS		
Regulatory assets (Note 4)	1,221,293	1,202,302
Assets for other postretirement benefits (Note 5)	29,094	268,978
Other	140,919	130,666
Total deferred debits	1,391,306	1,601,946
TOTAL ASSETS	$17,671,955	$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)

	September 30, 2018	December 31, 2017
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$249,059	$256,442
Accrued taxes	226,846	148,946
Accrued interest	53,021	56,397
Common dividends payable	—	77,667
Short-term borrowings (Note 3)	128,200	95,400
Current maturities of long-term debt (Note 3)	600,000	82,000
Customer deposits	89,916	70,388
Liabilities from risk management activities (Note 7)	45,504	59,252
Liabilities for asset retirements	13,000	4,745
Regulatory liabilities (Note 4)	159,788	100,086
Other current liabilities	169,454	246,529
Total current liabilities	1,734,788	1,197,852
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 3)	4,487,364	4,789,713
DEFERRED CREDITS AND OTHER		
Deferred income taxes	1,813,472	1,690,805
Regulatory liabilities (Note 4)	2,410,597	2,452,536
Liabilities for asset retirements	682,389	674,784
Liabilities for pension benefits (Note 5)	316,423	327,300
Liabilities from risk management activities (Note 7)	34,226	37,170
Customer advances	125,267	113,996
Coal mine reclamation	210,030	231,597
Deferred investment tax credit	198,178	205,575
Unrecognized tax benefits	11,896	13,115
Other	161,464	148,909
Total deferred credits and other	5,963,942	5,895,787
COMMITMENTS AND CONTINGENCIES (SEE NOTE 8)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 112,015,949 and 111,816,170 issued at respective dates	2,629,627	2,614,805
Treasury stock at cost; 17,368 and 64,463 shares at respective dates	(1,409)	(5,624)
Total common stock	2,628,218	2,609,181
Retained earnings	2,780,428	2,442,511
Accumulated other comprehensive loss	(55,074)	(45,002)
Total shareholders' equity	5,353,572	5,006,690
Noncontrolling interests (Note 6)	132,289	129,040
Total equity	5,485,861	5,135,730
TOTAL LIABILITIES AND EQUITY	$17,671,955	$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)

	Nine Months Ended September 30, 2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 499,591	$ 481,447
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	489,861	445,707
Deferred fuel and purchased power	(82,486)	(43,348)
Deferred fuel and purchased power amortization	92,397	(18,153)
Allowance for equity funds used during construction	(39,411)	(32,666)
Deferred income taxes	117,571	211,249
Deferred investment tax credit	(7,397)	(4,293)
Change in derivative instruments fair value	—	(254)
Stock compensation	16,140	16,553
Changes in current assets and liabilities:		
Customer and other receivables	(65,203)	(206,920)
Accrued unbilled revenues	(83,939)	(44,027)
Materials, supplies and fossil fuel	(20,591)	(1,881)
Income tax receivable	—	3,751
Other current assets	23,661	(22,043)
Accounts payable	(11,399)	(24,258)
Accrued taxes	78,624	89,827
Other current liabilities	12,852	3,936
Change in margin and collateral accounts — assets	(588)	(1,826)

Change in margin and collateral accounts — liabilities	(982)	(1,625)
Change in unrecognized tax benefits	(1,235)	5,891
Change in other long-term assets	14,708	(59,963)
Change in other long-term liabilities	(72,411)	(25,180)
Net cash flow provided by operating activities	959,763	771,924
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(898,455)	(1,027,753)
Contributions in aid of construction	22,611	24,924
Allowance for borrowed funds used during construction	(18,959)	(15,378)
Proceeds from nuclear decommissioning trust sales and other special use funds	443,215	351,860
Investment in nuclear decommissioning trust and other special use funds	(461,777)	(353,001)
Other	49	(20,291)
Net cash flow used for investing activities	(913,316)	(1,039,639)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	295,245	549,478
Short-term borrowing and payments — net	19,800	(68,800)
Short-term debt borrowings under revolving credit facility	45,000	23,000
Short-term debt repayments under revolving credit facility	(32,000)	—
Dividends paid on common stock	(228,037)	(213,927)
Repayment of long-term debt	(82,000)	—
Common stock equity issuance - net of	(1,984)	(8,870)

purchases				
Distributions to noncontrolling interests	(11,372	)	(11,372	)
Other	—		(1	)
Net cash flow provided by financing activities	4,652		269,508	
NET INCREASE IN CASH AND CASH EQUIVALENTS	51,099		1,793	
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	13,892		8,881	
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 64,991		$ 10,674	

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		—		—	466,827	—	14,620	481,447
Other comprehensive income		—		—	—	1,705	—	1,705
Dividends on common stock ($1.31 per share)		—		—	(146,204)	—	—	(146,204)
Issuance of common stock	274,823	12,795		—	—	—	—	12,795
Purchase of treasury stock (a)		—	(162,312)	(12,964)	—	—	—	(12,964)
Reissuance of treasury stock for stock-based compensation and other		—	207,765	16,264	23	—	1	16,288
Net capital activities by noncontrolling interests		—		—	—	—	(11,372)	(11,372)
Balance, September 30, 2017	111,666,876	$2,608,825	(9,864)	$(833)	$2,576,193	$ (42,117)	$ 135,539	$5,277,607
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		—		—	484,971	—	14,620	499,591
Other comprehensive income		—		—	—	(1,520)	—	(1,520)
Dividends on common stock ($1.39 per share)		—		—	(155,607)	—	—	(155,607)
Issuance of common stock	199,779	14,822		—	—	—	—	14,822
Purchase of treasury stock (a)		—	(81,278)	(6,285)	—	—	—	(6,285)
Reissuance of treasury stock for stock-based compensation and other		—	128,373	10,500	1	—	—	10,501
Net capital activities by noncontrolling interests		—		—	—	—	(11,372)	(11,372)
Reclassification of income tax effects related to new tax reform (See Note 13)		—		—	8,552	(8,552)	—	—
Other							1	1
Balance, September 30, 2018	112,015,949	$2,629,627	(17,368)	$(1,409)	$2,780,428	$ (55,074)	$ 132,289	$5,485,861

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

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
OPERATING REVENUES	$1,267,997	$1,178,846	$2,931,966	$2,799,840
OPERATING EXPENSES				
Fuel and purchased power	389,889	309,045	862,037	786,041
Operations and maintenance	226,346	222,374	732,946	657,157
Depreciation and amortization	145,949	133,486	434,594	386,010
Taxes other than income taxes	51,366	44,898	157,877	132,478
Other expenses	900	3,385	1,497	5,527
Total	814,450	713,188	2,188,951	1,967,213
OPERATING INCOME	453,547	465,658	743,015	832,627
OTHER INCOME (DEDUCTIONS)				
Allowance for equity funds used during construction	12,259	12,728	39,411	32,666
Pension and other postretirement non-service credits - net	12,812	6,477	38,398	19,430
Other income (Note 9)	6,153	738	16,160	1,432
Other expense (Note 9)	(3,361)	(2,178)	(9,679)	(8,608)
Total	27,863	17,765	84,290	44,920
INTEREST EXPENSE				
Interest charges	58,551	53,760	172,440	158,074
Allowance for borrowed funds used during construction	(5,913)	(6,000)	(18,959)	(15,378)
Total	52,638	47,760	153,481	142,696
INCOME BEFORE INCOME TAXES	428,772	435,663	673,824	734,851
INCOME TAXES	85,533	146,534	133,415	243,708
NET INCOME	343,239	289,129	540,409	491,143
Less: Net income attributable to noncontrolling interests (Note 6)	4,873	4,873	14,620	14,620
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$338,366	$284,256	$525,789	$476,523

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 September 30,		Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
NET INCOME	$343,239	$289,129	$540,409	$491,143
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Derivative instruments:				
Net unrealized gain (loss), net of tax expense $0, $5, $96 and $684 for the respective periods	—	9	(96)	(754)
Reclassification of net realized loss, net of tax benefit of $149, $438, $381 and $430 for the respective periods	451	710	1,316	2,480
Pension and other postretirement benefits activity, net of tax expense (benefit) of $313, $480, ($947) and $262 for the respective periods	952	777	(2,955)	81
Total other comprehensive income	1,403	1,496	(1,735)	1,807
COMPREHENSIVE INCOME	344,642	290,625	538,674	492,950
Less: Comprehensive income attributable to noncontrolling interests	4,873	4,873	14,620	14,620
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$339,769	$285,752	$524,054	$478,330

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

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

	September 30, 2018	December 31, 2017
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	$ 18,440,499	$ 17,654,078
Accumulated depreciation and amortization	(6,325,513)	(6,041,965)
Net	12,114,986	11,612,113
Construction work in progress	1,200,625	1,266,636
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	106,743	109,645
Intangible assets, net of accumulated amortization	268,474	257,028
Nuclear fuel, net of accumulated amortization	134,812	117,408
Total property, plant and equipment	13,825,640	13,362,830
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Note 12)	906,687	871,000
Other special use funds (Note 12)	233,740	30,358
Other assets	40,710	36,796
Total investments and other assets	1,181,137	938,154
CURRENT ASSETS		
Cash and cash equivalents	64,825	13,851
Customer and other receivables	350,028	292,791
Accrued unbilled revenues	196,373	112,434
Allowance for doubtful accounts	(5,215)	(2,513)
Materials and supplies (at average cost)	268,184	262,630
Fossil fuel (at average cost)	40,398	25,258
Assets from risk management activities (Note 7)	1,224	1,931
Deferred fuel and purchased power regulatory asset (Note 4)	65,726	75,637
Other regulatory assets (Note 4)	143,849	172,451
Other current assets	41,196	41,055
Total current assets	1,166,588	995,525
DEFERRED DEBITS		
Regulatory assets (Note 4)	1,221,293	1,202,302
Assets for other postretirement benefits (Note 5)	25,455	265,139
Other	129,026	129,801
Total deferred debits	1,375,774	1,597,242
TOTAL ASSETS	$ 17,549,139	$ 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)

	September 30, 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	2,909,180	2,533,954
Accumulated other comprehensive loss	(33,756)	(26,983)
Total shareholder equity	5,625,282	5,256,829
Noncontrolling interests (Note 6)	132,289	129,040
Total equity	5,757,571	5,385,869
Long-term debt less current maturities (Note 3)	4,188,724	4,491,292
Total capitalization	9,946,295	9,877,161
CURRENT LIABILITIES		
Current maturities of long-term debt (Note 3)	600,000	82,000
Accounts payable	241,548	247,852
Accrued taxes	263,521	157,349
Accrued interest	50,416	55,533
Common dividends payable	—	77,700
Customer deposits	89,916	70,388
Liabilities from risk management activities (Note 7)	45,504	59,252
Liabilities for asset retirements	13,000	4,192
Regulatory liabilities (Note 4)	159,788	100,086
Other current liabilities	165,206	243,922
Total current liabilities	1,628,899	1,098,274
DEFERRED CREDITS AND OTHER		
Deferred income taxes	1,834,691	1,742,485
Regulatory liabilities (Note 4)	2,410,597	2,452,536
Liabilities for asset retirements	682,389	666,527
Liabilities for pension benefits (Note 5)	296,987	306,542
Liabilities from risk management activities (Note 7)	34,226	37,170
Customer advances	125,267	113,996
Coal mine reclamation	210,030	215,830
Deferred investment tax credit	198,178	205,575
Unrecognized tax benefits	41,673	43,876
Other	139,907	133,779
Total deferred credits and other	5,973,945	5,918,316
COMMITMENTS AND CONTINGENCIES (SEE NOTE 8)		
TOTAL LIABILITIES AND EQUITY	$ 17,549,139	$ 16,893,751

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

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

	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 540,409	$ 491,143
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	488,223	444,439
Deferred fuel and purchased power	(82,486)	(43,348)
Deferred fuel and purchased power amortization	92,397	(18,153)
Allowance for equity funds used during construction	(39,411)	(32,666)
Deferred income taxes	86,319	202,256
Deferred investment tax credit	(7,397)	(4,293)
Change in derivative instruments fair value	—	(254)
Changes in current assets and liabilities:		
Customer and other receivables	(56,874)	(185,130)
Accrued unbilled revenues	(83,939)	(44,027)
Materials, supplies and fossil fuel	(20,694)	(1,755)
Income tax receivable	—	11,174
Other current assets	20,258	(19,100)
Accounts payable	(8,857)	(29,784)
Accrued taxes	106,172	102,638
Other current liabilities	9,289	11,747
Change in margin and collateral accounts — assets	(588)	(1,826)
Change in margin and collateral accounts — liabilities	(982)	(1,625)
Change in unrecognized tax benefits	(1,235)	5,891
Change in other long-term assets	25,993	(56,375)
Change in other long-term liabilities	(78,678)	(26,049)
Net cash flow provided by operating activities	987,919	804,903
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(889,347)	(1,008,723)
Contributions in aid of construction	22,611	24,924
Allowance for borrowed funds used during construction	(18,959)	(15,378)
Proceeds from nuclear decommissioning trust sales and other special use funds	443,040	351,860
Investment in nuclear decommissioning trust and other special use funds	(461,602)	(353,001)
Other	(1,261)	(18,098)
Net cash flow used for investing activities	(905,518)	(1,018,416)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	295,245	549,478
Short-term borrowings and payments — net	—	(103,700)
Short-term debt borrowings under revolving credit facility	25,000	—
Short-term debt repayments under revolving credit facility	(25,000)	—
Repayment of long-term debt	(82,000)	—
Dividends paid on common stock	(233,300)	(219,100)
Distributions to noncontrolling interests	(11,372)	(11,372)
Net cash flow provided by (used for) financing activities	(31,427)	215,306

NET INCREASE IN CASH AND CASH EQUIVALENTS	50,974	1,793
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	13,851	8,840
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 64,825	$ 10,633
Supplemental disclosure of cash flow information		
Cash paid during the period for:		
Income taxes, net of refunds	$ 24,746	$ 132
Interest, net of amounts capitalized	154,788	142,779
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 99,405	$ 94,769

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

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

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, January 1, 2017	71,264,947	$178,162	$2,421,696	$2,331,245	$ (25,423)	$ 132,290	$5,037,970
Net income		—	—	476,523	—	14,620	491,143
Other comprehensive income		—	—	—	1,807	—	1,807
Dividends on common stock		—	—	(146,198)	—	—	(146,198)
Net capital activities by noncontrolling interests		—	—	—	—	(11,372)	(11,372)
Other		—	—	—	—	1	1
Balance, September 30, 2017	71,264,947	$178,162	$2,421,696	$2,661,570	$ (23,616)	$ 135,539	$5,373,351
Balance, January 1, 2018	71,264,947	$178,162	$2,571,696	$2,533,954	$ (26,983)	$ 129,040	$5,385,869
Net income		—	—	525,789	—	14,620	540,409
Other comprehensive income		—	—	—	(1,735)	—	(1,735)
Dividends on common stock		—	—	(155,601)	—	—	(155,601)
Reclassification of income tax effects related to new tax reform (See Note 13)		—	—	5,038	(5,038)	—	—
Net capital activities by noncontrolling interests		—	—	—	—	(11,372)	(11,372)
Other		—	—	—	—	1	1
Balance, September 30, 2018	71,264,947	$178,162	$2,571,696	$2,909,180	$ (33,756)	$ 132,289	$5,757,571

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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Consolidation and Nature of Operations

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

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

Our condensed consolidated financial statements reflect all adjustments (consisting only of normal recurring adjustments except as otherwise disclosed in the notes) that we believe are necessary for the fair presentation of our financial position, results of operations, and cash flows for the periods presented. Certain information and footnote disclosures normally included in financial statements prepared in conformity with GAAP have been condensed or omitted pursuant to such regulations, although we believe that the disclosures provided are adequate to make the interim information presented not misleading. The accompanying condensed consolidated financial statements and these notes should be read in conjunction with the audited consolidated financial statements and notes included in our 2017 Form 10-K.

These condensed 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 the 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):

	Nine Months Ended September 30,	
	2018	2017
Cash paid during the period for:		
Income taxes, net of refunds	$10,091	$2,185
Interest, net of amounts capitalized	161,875	147,149
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$99,405	$93,031
Sale of 4CA's 7% interest in Four Corners	68,907	—

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 September 30, 2018	**Nine Months Ended September 30, 2018**
Retail residential electric service	$695,480	$1,512,402
Retail non-residential electric service	496,809	1,275,498
Wholesale energy sales	53,501	80,982
Transmission services for others	15,902	46,235
Other sources	6,342	19,754
Total operating revenues	$1,268,034	$2,934,871

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. 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 and nine months ended September 30, 2018 were $1,257 million and $2,897 million, respectively.

We have certain revenues that do not meet the specific accounting criteria to be classified as revenues from contracts with customers. For the three and nine months ended September 30, 2018, our revenues that do not qualify as revenue from contracts with customers were $11 million and $38 million, respectively. This relates primarily to certain regulatory cost recovery mechanisms that are considered alternative revenue programs. We recognize revenue associated with alternative revenue programs when specific events permitting recognition are completed. Certain amounts associated with alternative revenue programs will subsequently be billed to customers; however, we do not reclassify billed amounts into revenue from contracts with customers. See Note 4 for a discussion of our regulatory cost recovery mechanisms.

Contract Assets and Liabilities from Contracts with Customers

There were no material contract assets, contract liabilities, or deferred contract costs recorded on the Condensed Consolidated Balance Sheets as of September 30, 2018.

3. Long-Term Debt and Liquidity Matters

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

Pinnacle West

On June 28, 2018, Pinnacle West refinanced its 364-day $125 million unsecured revolving credit facility that would have matured on July 30, 2018 with a new 364-day $150 million credit facility that matures June

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

27, 2019. Borrowings under the facility bear interest at LIBOR plus 0.70% per annum. At September 30, 2018, Pinnacle West had $79 million outstanding under the facility.

On July 12, 2018, Pinnacle West replaced its $200 million revolving credit facility that would have matured in May 2021, with a new $200 million facility that matures in July 2023. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At September 30, 2018, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and $49 million of commercial paper borrowings.

APS

On May 30, 2018, APS purchased all $32 million of Maricopa County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds, 2009 Series C, due 2029. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2017.

On June 26, 2018, APS repaid at maturity APS's $50 million term loan facility.

On July 12, 2018, APS replaced its $500 million revolving credit facility that would have matured in May 2021, with a new $500 million facility that matures in July 2023.

On August 9, 2018, APS issued $300 million of 4.20% unsecured senior notes that mature on August 15, 2048. The net proceeds from the sale of the notes were used to repay commercial paper borrowings.

At September 30, 2018, APS had two revolving credit facilities totaling $1 billion, including a $500 million credit facility that matures in June 2022 and the above-mentioned $500 million facility. 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 September 30, 2018, APS had no 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 September 30, 2018		As of December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$298,640	$292,185	$298,421	$298,608
APS	4,788,724	4,900,210	4,573,292	5,006,348
Total	$5,087,364	$5,192,395	$4,871,713	$5,304,956

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 September 30, 2018, APS was in compliance with this common equity ratio requirement. Its total shareholder equity was approximately $5.6 billion, and total capitalization was approximately $10.6 billion. APS would be prohibited from paying dividends if the payment would reduce its total shareholder equity below approximately $4.2 billion, assuming APS's total capitalization remains the same.

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 of5.74% (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

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Arizonans, recoverable through the Arizona Renewable Energy Standard and Tariff ("RES"), to be no less than $10 million per year, and not more than $15 million per year;

- an increase to the per kWh cap for the environmental improvement surcharge from $0.00016 to $0.00050 and the addition of a balancing account;
- rate design changes, including:
  - a change in the on-peak time of use period from noon - 7 p.m. to 3 p.m. - 8 p.m. Monday through Friday, excluding holidays;
  - non-grandfathered distributed generation ("DG") customers would be required to select a rate option that has time of use rates and either a new grid access charge or demand component;
  - a Resource Comparison Proxy ("RCP") for exported energy of 12.9 cents per kWh in year one; and
- an agreement by APS not to pursue any new self-build generation (with certain exceptions) having an in-service date prior to January 1, 2022 (extended to December 31, 2027 for combined-cycle generating units), unless expressly authorized by the ACC.

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

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

On October 17, 2017, Warren Woodward (an intervener in APS's general retail rate case) filed a Notice of Appeal in the Arizona Court of Appeals, Division One. The notice raises a single issue related to the application of certain rate schedules to new APS residential customers after May 1, 2018. Mr. Woodward filed a second notice of appeal on November 13, 2017 challenging APS's $5 per month automated metering infrastructure opt-out program. Mr. Woodward's two appeals have been consolidated, and APS requested and was granted intervention. Mr. Woodward filed his opening brief on March 28, 2018. The ACC and APS filed responsive briefs on June 21, 2018. The Arizona Court of Appeals conferenced this matter on October 17, 2018, and APS anticipates a decision from the Arizona Court of Appeals by the end of 2018 or within the first half of 2019; however, the Arizona Court of Appeals is under no deadline to rule within a certain time period. APS cannot predict the outcome of this consolidated appeal but does not believe it will have a material impact on our financial position, results of operations or cash flows.

On January 3, 2018, an APS customer filed a petition with the ACC that was determined by the ACC Staff to be a complaint filed pursuant to Arizona Revised Statute §40-246 (the "Complaint") and not a request for rehearing. Arizona Revised Statute §40-246 requires the ACC to hold a hearing regarding any complaint alleging that a public service corporation is in violation of any commission order or that the rates being charged are not just and reasonable if the complaint is signed by at least twenty-five customers of the public service corporation. The Complaint alleged that APS is "in violation of commission order" [sic]. On February 13, 2018, the complainant filed an amended Complaint alleging that the rates and charges in the 2017 Rate Case Decision are not just and reasonable. The complainant requested that the ACC hold a hearing on the amended Complaint to determine if the average bill impact on residential customers of the rates and charges approved in the 2017 Rate Case Decision is greater than 4.54% (the average annual bill impact for a typical APS residential customer estimated by APS) and, if so, what effect the alleged greater bill impact has on APS's revenues and the overall reasonableness and justness of APS's rates and charges, in order to determine if there

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

is sufficient evidence to warrant a full-scale rate hearing. The ACC held a hearing on this matter beginning in September 2018 and the hearing was concluded on October 1, 2018. The parties filed the initial briefs in October 2018 and reply briefs are due on November 16, 2018. APS expects a recommended opinion and order from the judge within the first quarter of 2019. APS cannot predict the outcome of this matter.

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

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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 to $15 million in capital costs each year to install utility-owned DG systems for low to moderate income residential homes, buildings of non-profit entities, Title I schools and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES. On June 12, 2018, the ACC approved the 2018 RES Implementation Plan.

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

In September 2016, the ACC initiated a proceeding which will examine the possible modernization and expansion of the RES. On January 30, 2018, ACC Commissioner Tobin proposed a plan in this proceeding which would broaden the RES to include a series of energy policies tied to clean energy sources (the "Energy Modernization Plan"). The Energy Modernization Plan includes replacing the current RES standard with a new standard called the

Clean Resource Energy Standard and Tariff ("CREST"), which incorporates the proposals in the Energy Modernization Plan. A set of draft CREST rules for the ACC's consideration was issued by Commissioner Tobin's office on July 5, 2018. See "Energy Modernization Plan" below for more information on CREST.

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 was $62.6 million.

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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. The ACC has not yet ruled on the APS 2018 amended DSM Plan.

Power Supply Adjustor ("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):

	Nine Months Ended September 30,	
	2018	**2017**
Beginning balance	$75,637	$12,465
Deferred fuel and purchased power costs — current period	82,486	43,348
Amounts refunded/(charged) to customers	(92,397)	18,153
Ending balance	$65,726	$73,966

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

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

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.

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

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 were approved by FERC on May 22, 2018 and reduced APS's transmission rates compared to the rate that would have gone into effect absent these changes.

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

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$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). The ACC has not yet ruled on APS's 2018 LFCR adjustment request. Because the LFCR mechanism has a balancing account that trues up any under or over recoveries, a 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.

On August 13, 2018, APS filed a second request with the ACC to return an additional $86.5 million in tax savings to customers, starting January 1, 2019. This second request addresses amortization of non-depreciation related excess deferred taxes previously collected from customers. Additionally, as part of this second request, APS informed the ACC of its intent to file a third future request to address the amortization of depreciation related excess deferred taxes, as the Company is currently seeking IRS guidance regarding the amortization method and period it should apply to these depreciation related excess deferred taxes. The ACC has not yet approved this request.

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, FERC issued an order on May 22, 2018 authorizing APS to provide for the cost reductions resulting from the income tax changes in its wholesale transmission rates.

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Net Metering

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

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

In addition, the ACC made the following determinations:

- Customers who have interconnected a DG system or submitted an application for interconnection for DG systems prior to 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
- Once an export price is set for APS, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future general retail rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies. A first-year export energy price of 12.9 cents per kWh is included in the 2017 Settlement Agreement and became effective on August 19, 2017.

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

On January 23, 2017, The Alliance for Solar Choice ("TASC") sought rehearing of the ACC's decision regarding the value and cost of DG. TASC asserted that the ACC improperly ignored the Administrative Procedure Act, failed to give adequate notice regarding the scope of the proceedings, and relied on information that was not submitted as evidence, among other alleged defects. TASC filed a Notice of Appeal in the Court of Appeals and filed a Complaint and Statutory Appeal in the Maricopa County Superior Court on March 10,

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2017. As part of the 2017 Settlement Agreement described above, TASC agreed to withdraw these appeals when the ACC decision implementing the 2017 Settlement Agreement is no longer subject to appellate review.

Subpoena from Arizona Corporation Commissioner Robert Burns

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

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

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

On August 4, 2017, Commissioner Burns amended his complaint to add all of the ACC Commissioners and the ACC itself as defendants. All defendants moved to dismiss the amended complaint. On February 15, 2018, the Superior Court dismissed Commissioner Burns' amended complaint. On March 6, 2018, Commissioner Burns filed an objection to the proposed final order from the Superior Court and a motion to further amend his complaint. The Superior Court permitted Commissioner Burns to amend his complaint to add a claim regarding his attempted investigation into whether his fellow commissioners should have been disqualified from voting on APS's 2017 rate case. Commissioner Burns has now served his second amended complaint, and responsive filings were due on June 25, 2018. All defendants filed responses opposing the second amended complaint and requested that it be dismissed. Oral argument is scheduled for November 13, 2018 regarding the motion to dismiss. APS and Pinnacle West cannot predict the outcome of this matter.

Renewable Energy Ballot Initiative

On February 20, 2018, a renewable energy advocacy organization filed with the Arizona Secretary of State a ballot initiative for an Arizona constitutional amendment requiring Arizona public service corporations

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to provide at least 50% of their annual retail sales of electricity from renewable sources by 2030. For purposes of the proposed amendment, eligible renewable sources would not include nuclear generating facilities. The initiative was placed on the November 2018 Arizona elections ballot. On November 6, 2018, the initiative failed to receive adequate voter support and was defeated.

Energy Modernization Plan

On January 30, 2018, ACC Commissioner Tobin proposed the Energy Modernization Plan, which consists of a series of energy policies tied to clean energy sources such as energy storage, biomass, energy efficiency, electric vehicles, and expanded energy planning through the integrated resource plans ("IRP") process. The Energy Modernization Plan includes replacing the current RES standard with a new standard called the CREST, which incorporates the proposals in the Energy Modernization Plan. On 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. On July 5, 2018, Commissioner Tobin’s office issued a set of draft CREST rules for the ACC’s consideration.

In August 2018, the ACC directed ACC Staff to open a new rulemaking docket which will address a wide range of energy issues, including the Energy Modernization Plan proposals. The rulemaking will consider possible modifications to existing ACC rules, such as the Renewable Energy Standard, Electric and Gas Energy Efficiency Standards, Net Metering, Resource Planning, and the Biennial Transmission Assessment, as well as the development of new rules regarding forest bioenergy, electric vehicles, interconnection of distributed generation, baseload security, blockchain technology and other technological developments, retail competition, and other energy-related topics. No additional action has been taken in this rulemaking docket to date. APS cannot predict the outcome of this matter.

Integrated Resource Planning

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

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

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balance related to the acquisition of SCE’s interest in Units 4 and 5 and the closure of Units 1-3 was $50 million as of September 30, 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 Adjustment to permit recovery of costs associated with the installation of SCR equipment at Four Corners Units 4 and 5. APS filed the SCR Adjustment request in April 2018. Consistent with the 2017 Rate Case Decision, the request was narrow in scope and addressed only costs associated with this specific environmental compliance equipment. The SCR Adjustment request provided that there would be a $67.5 million annual revenue impact that would be applied as a percentage of base rates for all applicable customers. Also, as provided for in the 2017 Rate Case Decision, APS requested that the adjustment become effective no later than January 1, 2019. The hearing for this matter occurred in September 2018. At the hearing, APS accepted ACC Staff's recommendation of a lower annual revenue impact of approximately $58.5 million. A decision in this matter is expected early in the first quarter of 2019.

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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 ($93 million as of September 30, 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 current owners of 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 ($90 million as of September 30, 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	September 30, 2018		December 31, 2017	
		Current	Non-Current	Current	Non-Current
Pension	(a)	$—	$ 598,031	$—	$ 576,188
Retired power plant costs	2033	28,182	174,257	27,402	188,843
Income taxes — allowance for funds used during construction ("AFUDC") equity	2048	5,882	150,684	3,828	142,852
Deferred fuel and purchased power — mark-to-market (Note 7)	2022	41,062	33,215	52,100	34,845
Deferred fuel and purchased power (b) (d)	2019	65,726	—	75,637	—
Four Corners cost deferral	2024	8,077	42,247	8,077	48,305
Income taxes — investment tax credit basis adjustment	2047	1,066	25,239	1,066	26,218
Lost fixed cost recovery (b)	2019	36,125	—	59,844	—
Palo Verde VIEs (Note 6)	2046	—	19,860	—	19,395
Deferred compensation	2036	—	37,854	—	36,413
Deferred property taxes	2027	8,569	68,499	8,569	74,926
Loss on reacquired debt	2038	1,637	14,078	1,637	15,305
Tax expense of Medicare subsidy	2024	1,235	6,253	1,236	7,415
TCA balancing account (b)	2019	7,087	—	1,220	—
AG-1 deferral	2022	2,654	6,482	2,654	8,472
Mead-Phoenix transmission line CIAC	2050	332	10,127	332	10,376
Coal reclamation	2026	1,546	11,695	1,068	12,396
SCR deferral	N/A	—	16,319	—	353
Other	Various	395	6,453	3,418	—
Total regulatory assets (c)		$209,575	$ 1,221,293	$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.

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	Amortization Through	September 30, 2018		December 31, 2017	
		Current	Non-Current	Current	Non-Current
Excess deferred income taxes - ACC - Tax Cuts and Jobs Act	(a)	$—	$ 1,273,153	$—	$ 1,266,104
Excess deferred income taxes - FERC - Tax Cuts and Jobs Act	2058	6,284	243,369	—	254,170
Asset retirement obligations	2057	—	344,402	—	332,171
Removal costs	(b)	30,871	196,065	18,238	209,191
Other postretirement benefits	(d)	37,842	123,683	37,642	151,985
Income taxes — deferred investment tax credit	2047	2,137	50,555	2,164	52,497
Income taxes — change in rates	2047	2,799	71,137	2,573	70,537
Spent nuclear fuel	2027	7,769	57,400	6,924	62,132
Renewable energy standard (c)	2019	41,912	92	23,155	—
Demand side management (c)	2019	16,099	4,124	3,066	4,921
Sundance maintenance	2030	—	18,104	—	16,897
Deferred gains on utility property	2022	4,423	7,704	4,423	10,988
Four Corners coal reclamation	2038	1,858	17,972	1,858	18,921
Tax expense adjustor mechanism (c)	2018	7,433	—	—	—
Other	Various	361	2,837	43	2,022
Total regulatory liabilities		$159,788	$ 2,410,597	$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. 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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

employee medical costs. On January 2, 2018, these funds were moved to the new trust account which is 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 September 30,		**Nine Months Ended September 30,**		**Other Benefits Three Months Ended September 30,**		**Nine Months Ended September 30,**	
	2018	**2017**	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**
Service cost — benefits earned during the period	$14,167	$13,715	$42,501	$41,144	$5,275	$4,280	$15,825	$12,839
Non-service costs (credits):								
Interest cost on benefit obligation	31,172	32,439	93,517	97,316	7,037	7,490	21,111	22,470
Expected return on plan assets	(45,713)	(43,568)	(137,140)	(130,703)	(10,520)	(13,350)	(31,561)	(40,051)
Amortization of:								
Prior service cost (credit)	—	20	—	61	(9,461)	(9,461)	(28,382)	(28,382)
Net actuarial loss	8,021	11,975	24,062	35,924	—	1,279	—	3,838
Net periodic benefit cost (credit)	$7,647	$14,581	$22,940	$43,742	$(7,669)	$(9,762)	$(23,007)	$(29,286)
Portion of cost (credit) charged to expense	$2,524	$7,231	$7,535	$21,692	$(5,359)	$(4,841)	$(16,083)	$(14,523)

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 $72 million for prior years 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 and nine months ended September 30, 2018 of $5 million and $15 million respectively, and for the three and nine months ended September 30, 2017 of $5 million and $15 million, respectively, entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

Our Condensed Consolidated Balance Sheets at September 30, 2018 and December 31, 2017 include the following amounts relating to the VIEs (dollars in thousands):

	September 30, 2018	**December 31, 2017**
Palo Verde sale leaseback property plant and equipment, net of accumulated depreciation	$106,743	$109,645
Equity — Noncontrolling interests	132,289	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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 sheets as an asset or liability and are measured at fair value. See Note 11 for a discussion of fair value measurements. Derivative instruments may qualify for the normal purchases and normal sales scope exception if they require physical delivery and the quantities represent those transacted in the normal course of business. Derivative instruments qualifying for the normal purchases and sales scope exception are accounted for under the accrual method of accounting and excluded from our derivative instrument discussion and disclosures below.

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

As of September 30, 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**	
		September 30, 2018	**December 31, 2017**
Power	GWh	287	583
Gas	Billion cubic feet	192	240

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 and nine months ended September 30, 2018 and 2017 (dollars in thousands):

	Financial Statement Location	Three Months Ended September 30,		Nine Months Ended September 30,	
Commodity Contracts		**2018**	**2017**	**2018**	**2017**
Gain (Loss) Recognized in OCI on Derivative Instruments (Effective Portion)	OCI — derivative instruments	$ —	$ 14	$ —	$ (70)
Loss Reclassified from Accumulated OCI into Income (Effective Portion Realized) (a)	Fuel and purchased power (b)	(600)	(1,148)	(1,697)	(2,910)

(a) During the three and nine months ended September 30, 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, 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 and nine months ended September 30, 2018 and 2017 (dollars in thousands):

	Financial Statement Location	Three Months Ended September 30,		Nine Months Ended September 30,	
Commodity Contracts		**2018**	**2017**	**2018**	**2017**

Net Loss Recognized in Income	Operating revenues	$(1,029)	$(128)	$(2,590)	$(474)
Net Gain (Loss) Recognized in Income	Fuel and purchased power (a)	4,263	(6,100)	(26,442)	(64,143)
Total		$3,234	$(6,228)	$(29,032)	$(64,617)

(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

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 September 30, 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 September 30, 2018: (dollars in thousands)	**Gross Recognized Derivatives (a)**	**Amounts Offset (b)**	**Net Recognized Derivatives**	**Other (c)**	**Amount Reported on Balance Sheets**
Current assets	$ 2,609	$ (2,273)	$ 336	$ 888	$ 1,224
Investments and other assets	314	(314)	—	—	—
Total assets	2,923	(2,587)	336	888	1,224
Current liabilities	(45,238)	2,273	(42,965)	(2,539)	(45,504)
Deferred credits and other	(34,540)	314	(34,226)	—	(34,226)
Total liabilities	(79,778)	2,587	(77,191)	(2,539)	(79,730)
Total	$ (76,855)	$ —	$ (76,855)	$ (1,651)	$ (78,506)

(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 $2,539 and cash margin provided to counterparties of $888.

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 Sheets
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 September 30, 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 September 30, 2018 (dollars in thousands):

	September 30, 2018
Aggregate fair value of derivative instruments in a net liability position	$ 79,778
Cash collateral posted	—
Additional cash collateral in the event credit-risk-related contingent features were fully triggered (a)	76,299

(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, 2017. The DOE has approved and paid $74.2 million for these claims (APS’s share is$21.6 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 Rate Case Decision, this regulatory liability is being refunded to customers (see Note 4). APS's next claim pursuant to the terms of the August 18, 2014 settlement agreement is required to be filed with DOE no later than October 31, 2018. The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 occurring on or prior to October 31, 2018 of up to approximately $13.1 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $450 million, which is provided by American Nuclear Insurers ("ANI"). The remaining balance of approximately $12.6 billion of liability coverage is provided through a mandatory industry-wide retrospective premium program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be responsible for retrospective premiums. For losses on or prior to October 31, 2018, the maximum total deferred 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 standard deferred premium of approximately $16.6 million.

On September 24, 2018, the NRC announced a statutorily mandated once per five year inflation adjustment to the maximum total deferred premium and the annual standard deferred premium. Effective November 1, 2018, the inflation adjusted maximum total deferred premium per reactor is approximately $137.6 million per incident, subject to the maximum annual deferred premium of approximately $20.5 million. Based on APS's ownership interest in the three Palo Verde units, for covered incidents occurring on or after November 1, 2018, APS's maximum total deferred premium per incident for all three units is approximately $120.1 million, with a maximum annual standard deferred premium of approximately $17.9 million.

The Palo Verde participants maintain insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion. APS has also secured accidental outage insurance for a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and accidental outage insurance are provided by Nuclear Electric Insurance Limited ("NEIL"). APS is subject to retrospective premium adjustments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $24.8 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. In addition, NEIL policies contain rating triggers that would result in APS providing approximately $71.2 million of collateral assurance within 20 business days of a rating downgrade to non-investment grade. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions, sublimits and exclusions.

Contractual Obligations

For the nine months ended September 30, 2018, our fuel and purchased power commitments decreased approximately $166 million from amounts reported at December 31, 2017, primarily due to the amended and restated Four Corners 2016 Coal Supply Agreement effective in the second quarter of 2018. The majority of these changes relate to the years 2023 and thereafter.

Other than the items described above, there have been no material changes, as of September 30, 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 environmental and engineering contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another RID service provider filed an additional ancillary CERCLA lawsuit against certain of the defendants in the main RID litigation, but excluded APS and certain other parties as named defendants. Because the ancillary lawsuits concern past costs allegedly incurred by these RID vendors, which were ruled unrecoverable directly by RID in November of 2016, the additional lawsuits do not increase APS's exposure or risk related to these matters.

On April 5, 2018, RID and the defendants in that particular litigation executed a settlement agreement, fully resolving RID's CERCLA claims concerning both past and future cost recovery. APS's share of this settlement was immaterial. In addition, the two environmental and engineering vendors voluntarily dismissed their lawsuit against APS and the other named defendants without prejudice. An order to this effect was entered on April 17, 2018. With this disposition of the case, the vendors may file their lawsuit again in the future. In addition, APS and certain other parties not named in the remaining RID service provider lawsuit may be brought into the litigation via third-party complaints filed by the current direct defendants. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of both conventional pollutants and greenhouse gases, water

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quality, wastewater discharges, solid waste, hazardous waste, and coal combustion residuals ("CCRs"). These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates, but cannot predict whether it will obtain such recovery. The following proposed and final rules involve material compliance costs to APS.

Regional Haze Rules. APS has received the final rulemaking imposing new pollution control requirements on Four Corners and the Navajo Plant. EPA will require these plants to install pollution control equipment that constitutes best available retrofit technology ("BART") to lessen the impacts of emissions on visibility surrounding the plants. In addition, EPA 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") purchased the interest from 4CA on July 3, 2018. See "Four Corners Coal Supply Agreement - 4CA Matter" below for a discussion of the NTEC purchase. The cost of the pollution controls related to the 7% interest is approximately $45 million, which was assumed by NTEC through its purchase of the 7% interest.

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

Cholla. APS believed that EPA's original 2012 final rule establishing controls constituting BART for Cholla, which would require installation of SCR controls, was unsupported and that EPA had no basis for disapproving Arizona's State Implementation Plan ("SIP") and promulgating a FIP that was inconsistent with the state's considered BART determinations under the regional haze program. In September 2014, APS met with EPA to propose a compromise BART strategy. 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

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minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent’s groundwater protection standard to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments, and are the subject of recent regulatory and judicial activities described below.
On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation ("WIIN") Act into law, which contains a number of provisions requiring EPA to modify the self-implementing provisions of the Agency's current CCR rules under Subtitle D. Such modifications include new EPA authority to directly enforce the CCR rules through the use of administrative orders and providing states, like Arizona, where the Cholla facility is located, the option of developing CCR disposal unit permitting programs, subject to EPA approval. For facilities in states that do not develop state-specific permitting programs, EPA is required to develop a federal permit program, pending the availability of congressional appropriations. By contrast, for facilities located within the boundaries of Native American tribal reservations, such as the Navajo Nation, where the Navajo Plant and Four Corners facilities are located, EPA is required to develop a federal permit program regardless of appropriated funds.

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

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

Pursuant to a June 24, 2016 order by the D.C. Circuit Court of Appeals in the litigation by industry- and environmental-groups challenging EPA’s CCR regulations, EPA is required to complete a rulemaking proceeding in the near future concerning whether or not boron must be included on the list of groundwater

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constituents that might trigger corrective action under EPA's CCR rules. Simultaneously with the issuance of EPA's proposed modifications to the federal CCR rules in response to industry petitions, on March 1, 2018, EPA issued a proposed rule seeking comment as to whether or not boron should be included on this list. EPA is not required to take final action approving the inclusion of boron. Should EPA take final action adding boron to the list of groundwater constituents that might trigger corrective action, any resulting corrective action measures may increase APS's costs of compliance with the CCR rule at our coal-fired generating facilities. At this time APS cannot predict the eventual results of this rulemaking proceeding concerning boron.

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

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.

APS recently completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, to the extent that compliance with the CCR rule did not otherwise trigger the need for these CCR disposal units to close, such units must all cease operating and initiate closure by October of 2020. APS currently estimates that the additional incremental costs to complete this corrective action and closure work, along with the costs to develop replacement CCR disposal capacity, could be approximately $5 million for both Cholla and Four Corners. APS will initiate an assessment of corrective measures by January of 2019, during which APS will gather additional groundwater data, solicit input from the public, host a public hearing, and select a remedy. As such, this $5 million cost estimate may change based upon APS’s performance of the CCR rule’s corrective action assessment process, which APS anticipates completing during the summer or fall of 2019. Given uncertainties that may exist until we have fully completed the corrective action assessment process, we cannot predict any ultimate impacts to the Company; however, at this time we do not believe any potential change to the cost estimate would have a material impact on our financial position, results of operations or cash flows.

Clean Power Plan. On 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,

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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.

On August 21, 2018, EPA issued a Notice of Proposed Rulemaking for regulations that would replace the Clean Power Plan, which are based entirely upon measures that can be implemented to improve the heat rate of steam-electric power plants, essentially coal-fired EGUs. In contrast with the Clean Power Plan, EPA’s proposed “Affordable Clean Energy Rule” would not involve utility-level generation dispatch shifting away from coal-fired generation and toward renewable energy resources and natural gas-fired combined cycle power plants. In addition, to address the New Source Review implications of power plant upgrades potentially necessary to achieve compliance with the proposed Affordable Clean Energy Rule standards, EPA also proposed to revise the EPA's New Source Review regulations to more readily authorize the implementation of EGU efficiency upgrades.

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

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

Federal Agency Environmental Lawsuit Related to Four Corners

On April 20, 2016, several environmental groups filed a lawsuit against the Office of Surface Mining Reclamation and Enforcement ("OSM") and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit

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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. The parties anticipate oral arguments to be heard in early 2019. We cannot predict whether this appeal will be successful and, if it is successful, the outcome of further district court proceedings.

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

On July 16, 2018, several environmental groups filed a petition for review before the EPA Environmental Appeals Board ("EAB") concerning the NPDES wastewater discharge permit for Four Corners, which was reissued on June 12, 2018. The environmental groups allege that the permit was reissued in contravention of several requirements under the Clean Water Act and did not contain required provisions concerning EPA’s 2015 revised effluent limitation guidelines for steam-electric EGUs, 2014 existing-source regulations governing cooling-water intake structures, and effluent limits for surface seepage and subsurface discharges from coal-ash disposal facilities. These groups are seeking to have the permit remanded back to EPA for revision to address these allegations. At this time, we cannot predict whether this EAB permit appeal will be successful, and if so whether the results of those proceedings will have a material impact on our financial position, results of operations or cash flows.

Four Corners Coal Supply Agreement

Arbitration

On June 13, 2017, APS received a Demand for Arbitration from NTEC in connection with the 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 (the "2016 Coal Supply Agreement"). 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.

On June 29, 2018, the parties settled 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. In connection with the settlement, the parties amended the 2016 Coal Supply Agreement, including modifying 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 arbitration was dismissed on July 9, 2018.

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Coal Advance Purchase

On March 12, 2018, APS paid to NTEC approximately $24 million as an advance payment for APS's share of coal under the 2016 Coal Supply Agreement. 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 of the 2016 Coal Supply Agreement matter described above, NTEC and 4CA agreed to allow for the purchase by NTEC of the 7% interest, consistent with the option. On June 29, 2018, 4CA and NTEC entered into an asset purchase agreement providing for the sale to NTEC of 4CA's 7% interest in Four Corners. Completion of the sale was subject to the receipt of approval by FERC, which was received on July 2, 2018, and the sale transaction closed on July 3, 2018. NTEC purchased the 7% interest at 4CA's book value, approximately $70 million, and will pay 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note. In connection with the sale, Pinnacle West guaranteed certain obligations that NTEC will have to the other owners of Four Corners, such as NTEC's 7% share of capital expenditures and operating and maintenance expenses. Pinnacle West's guarantee is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement.

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

NTEC satisfied by directing to 4CA a prepayment from APS of a portion of a future mine reclamation obligation. The balance of the amount under this formula at September 30, 2018 for the calendar year 2017 is approximately $20 million, which is due to 4CA at December 31, 2018. The balance of the amount under this formula at September 30, 2018 for the calendar year 2018 (up to the date that NTEC purchased the 7% interest) is approximately $10 million, which is due to 4CA at December 31, 2019.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support commodity contract collateral obligations and other transactions. As of September 30, 2018, standby letters of credit totaled $0.2 million and will expire in 2019. As of September 30, 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

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maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

Pinnacle West has issued parental guarantees and has provided indemnification under certain surety bonds for APS which were not material at September 30, 2018. Since July 6, 2016, Pinnacle West has issued five 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, two of which terminated in connection with the sale of 4CA's 7% interest to NTEC and two that will terminate in the near future. (See "Four Corners Coal Supply Agreement - 4CA Matter" above for information related to this sale.)

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

9. Other Income and Other Expense

The following table provides detail of Pinnacle West's Consolidated other income and other expense for the three and nine months ended September 30, 2018 and 2017 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
Other income:				
Interest income	$1,957	$917	$6,256	$1,782
Debt return on Four Corners SCR deferral (Note 4)	4,910	—	11,190	—
Miscellaneous	91	174	95	273
Total other income	$6,958	$1,091	$17,541	$2,055
Other expense:				
Non-operating costs	$(2,480)	$(1,978)	$(7,404)	$(7,338)
Investment losses — net	—	(231)	(268)	(759)
Miscellaneous	(2,583)	(2,784)	(4,391)	(4,398)
Total other expense	$(5,063)	$(4,993)	$(12,063)	$(12,495)

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The following table provides detail of APS's other income and other expense for the three and nine months ended September 30, 2018 and 2017 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Other income:				
Interest income	$1,151	$683	$4,874	$1,278
Debt return on Four Corners SCR deferral (Note 4)	4,910	—	11,190	—
Miscellaneous	92	55	96	154
Total other income	$6,153	$738	$16,160	$1,432
Other expense:				
Non-operating costs	$(2,334)	$(1,734)	$(6,931)	$(6,625)
Miscellaneous	(1,027)	(444)	(2,748)	(1,983)
Total other expense	$(3,361)	$(2,178)	$(9,679)	$(8,608)

10. Earnings Per Share

The following table presents the calculation of Pinnacle West's basic and diluted earnings per share for the three and nine months ended September 30, 2018 and 2017 (in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net income attributable to common shareholders	$315,012	$276,072	$484,971	$466,827
Weighted average common shares outstanding — basic	112,148	111,835	112,094	111,787
Net effect of dilutive securities:				
Contingently issuable performance shares and restricted stock units	385	566	405	527
Weighted average common shares outstanding — diluted	112,533	112,401	112,499	112,314
Earnings per weighted-average common share outstanding				
Net income attributable to common shareholders — basic	$2.81	$2.47	$4.33	$4.18
Net income attributable to common shareholders — diluted	$2.80	$2.46	$4.31	$4.16

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.

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

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

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

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

Recurring Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, and investments held in the nuclear decommissioning trust and other special use funds. On an annual basis we apply fair value measurements to plan assets held in our retirement and other benefit plans. See Note 7 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

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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

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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.

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Fair Value Tables

The following table presents the fair value at September 30, 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 September 30, 2018
Assets						
Cash equivalents	$ 5,600	$—	$ —	$—		$5,600
Risk management activities — derivative instruments:						
Commodity contracts	—	2,865	58	(1,699)	(b)	1,224
Nuclear decommissioning trust:						
Equity securities	6,213	—	—	(625)	(c)	5,588
U.S. commingled equity funds	—	—	—	459,790	(d)	459,790
U.S. Treasury debt	134,462	—	—	—		134,462
Corporate debt	—	104,953	—	—		104,953
Mortgage-backed debt securities	—	112,036	—	—		112,036
Municipal bonds	—	80,787	—	—		80,787
Other fixed income	—	9,071	—	—		9,071
Subtotal nuclear decommissioning trust	140,675	306,847	—	459,165		906,687
Other special use funds:						
Equity securities	12,033	—	—	1,722	(c)	13,755
U.S. Treasury debt	199,094	—	—	—		199,094
Municipal bonds	—	20,891	—	—		20,891
Subtotal other special use funds	211,127	20,891	—	1,722		233,740
Total Assets	$ 357,402	$330,603	$ 58	$459,188		$1,147,251
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$(69,857)	$ (9,921)	$48	(b)	$(79,730)

(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.

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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).

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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 September 30, 2018 and December 31, 2017:

	September 30, 2018 Fair Value (thousands)		Valuation Technique	Significant Unobservable Input		Weighted-Average
Commodity Contracts	**Assets**	**Liabilities**			**Range**	
Natural Gas:						
Forward Contracts (a)	$58	$9,921	Discounted cash flows	Natural gas forward price (per MMBtu)	$1.75 - $2.74	$ 2.23
Total	$58	$9,921				

(a) Includes swaps and physical and financial contracts.

	December 31, 2017 Fair Value (thousands)		Valuation Technique	Significant Unobservable Input		Weighted-Average
Commodity Contracts	**Assets**	**Liabilities**			**Range**	
Electricity:						
Forward Contracts (a)	$21	$15,485	Discounted cash flows	Electricity forward price (per MWh)	$18.51 - $38.75	$ 27.89
Natural Gas:						
Forward Contracts (a)	1,015	3,807	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.33 - $3.11	$ 2.71
Total	$1,036	$19,292				

(a) Includes swaps and physical and financial contracts.

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The following table shows the changes in fair value for our risk management activities' assets and liabilities that are measured at fair value on a recurring basis using Level 3 inputs for the three and nine months ended September 30, 2018 and 2017 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Commodity Contracts	**2018**	**2017**	**2018**	**2017**
Net derivative balance at beginning of period	$(9,358)	$(36,245)	$(18,256)	$(47,406)
Total net gains (losses) realized/unrealized:				
Included in OCI	—	(4)	—	(10)
Deferred as a regulatory asset or liability	1,244	(3,769)	(2,067)	(11,272)
Settlements	(2,332)	1,733	(1,056)	4,855
Transfers into Level 3 from Level 2	(2,246)	(5,952)	(7,225)	(10,340)
Transfers from Level 3 into Level 2	2,829	5,632	18,741	25,568
Net derivative balance at end of period	$(9,863)	$(38,605)	$(9,863)	$(38,605)
Net unrealized gains included in earnings related to instruments still held at end of period	$—	$—	$—	$—

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

Financial Instruments Not Carried at Fair Value

The carrying value of our short-term borrowings approximate fair value and are classified within Level 2 of the fair value hierarchy. See Note 3 for our long-term debt fair values. The NTEC note receivable related to the sale of 4CA's interest in Four Corners bears interest at 3.9% per annum and has a book value of $65 million as of September 30, 2018 as presented on the Condensed Consolidated Balance Sheets. The carrying amount is not materially different from the fair value of the note receivable and is classified within Level 3 of the fair value hierarchy. See Note 8 for more information on 4CA matters.

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

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

Nuclear Decommissioning Trusts - To fund the future costs APS expects to incur to decommission Palo Verde, APS established external decommissioning trusts in accordance with NRC regulations. Third-party investment managers are authorized to buy and sell securities per stated investment guidelines. The trust funds are invested in fixed income securities and equity securities. Earnings and proceeds from sales and maturities of securities are reinvested in the trusts. Because of the ability of APS to recover decommissioning

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costs in rates, and in accordance with the regulatory treatment, APS has deferred realized and unrealized gains and losses (including other-than-temporary impairments) in other regulatory liabilities.

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

Active Union Employee Medical Account - APS has investments restricted for paying active union employee medical costs. These investments were transferred from APS other postretirement benefit trust assets into the active union employee medical trust in January 2018 (see Note 7 in the 2017 Form 10-K). These investments may be used to pay active union employee medical costs incurred in the current period and in future periods. The account is invested primarily in fixed income securities. In accordance with the ratemaking treatment, APS has deferred the unrealized gains and losses (including other-than-temporary impairments) in other regulatory assets. Activities relating to active union employee medical account investments are included within the other special use funds in the table below.

APS

The following tables present the unrealized gains and losses based on the original cost of the investment and summarizes the fair value of APS's nuclear decommissioning trust and other special use fund assets at September 30, 2018 and December 31, 2017 (dollars in thousands):

	September 30, 2018				
	Fair Value				
Investment Type:	**Nuclear Decommissioning Trusts**	**Other Special Use Funds**	**Total**	**Total Unrealized Gains**	**Total Unrealized Losses**

Equity securities	$466,002	$12,033	$478,035		$286,121	$(47)
Available for sale-fixed income securities	441,309	219,985	661,294	(a)	5,631	(11,423)
Other	(624)	1,722	1,098	(b)	—	—
Total	$906,687	$233,740	$1,140,427		$291,752	$(11,470)

(a) As of September 30, 2018, the amortized cost basis of these available-for-sale investments is $667 million.

(b) Represents net pending securities sales and purchases.

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	December 31, 2017					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$424,614	$430	$425,044		$248,623	$—
Available for sale-fixed income securities	446,277	29,439	475,716	(a)	11,537	(2,996)
Other	109	489	598	(b)	—	—
Total	$871,000	$30,358	$901,358		$260,160	$(2,996)

(a) As of December 31, 2017, the amortized cost basis of these available-for-sale investments is $467 million.

(b) Represents net pending securities sales and purchases.

The following table sets forth APS's realized gains and losses relating to the sale and maturity of available-for-sale debt securities and equity securities, and the proceeds from the sale and maturity of these investment securities for the three and nine months ended September 30, 2018 and September 30, 2017 (dollars in thousands):

	Three Months Ended September 30, 2018			Three Months Ended September 30, 2017		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
Realized gains	$653	$ —	$ 653	$598	$ —	$ 598
Realized losses	(1,965)	—	(1,965)	(1,022)	—	(1,022)
Proceeds from the sale of securities (a)	148,150	25,127	173,277	76,496	—	76,496

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

	Nine Months Ended September 30, 2018			Nine Months Ended September 30, 2017		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
Realized gains	$2,951	$ 1	$2,952	$3,904	$ 17	$3,921
Realized losses	(6,990)	—	(6,990)	(4,634)	(9)	(4,643)

Proceeds from the sale of securities (a)	401,396	41,644	443,040	351,860	4,093	355,953

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

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The fair value of APS's fixed income securities, summarized by contractual maturities, at September 30, 2018, is as follows (dollars in thousands):

	Nuclear Decommissioning Trusts (a)	Coal Reclamation Escrow Accounts	Active Union Medical Trust	Total
Less than one year	$ 19,917	$ 17,244	$30,593	$67,754
1 year – 5 years	98,235	17,170	142,598	258,003
5 years – 10 years	126,279	2,529	—	128,808
Greater than 10 years	196,878	9,851	—	206,729
Total	$ 441,309	$ 46,794	$173,191	$661,294

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

13. New Accounting Standards

Standards Adopted during 2018

ASU 2014-09, Revenue from Contracts with Customers

In May 2014, a new revenue recognition accounting standard was issued. This standard provides a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most prior revenue recognition guidance. Since the issuance of the new revenue standard, additional guidance was issued to clarify certain aspects of the new revenue standard, including principal versus agent considerations, identifying performance obligations, and other narrow scope improvements. The new revenue standard, and related amendments, were effective for us on January 1, 2018. The standard may be adopted using a full retrospective application or a simplified transition method that allows entities to record a cumulative effect adjustment in retained earnings at the date of initial application.

We adopted this standard, and related amendments, on January 1, 2018, using the modified retrospective transition approach. The adoption of the new revenue guidance resulted in expanded disclosures, but otherwise did not have a material impact on our financial statements. See Note 2.

ASU 2016-01, Financial Instruments: Recognition and Measurement

In January 2016, a new accounting standard was issued relating to the recognition and measurement of financial instruments. The new guidance requires certain investments in equity securities to be measured at fair value with changes in fair value recognized in net income, and modifies the impairment assessment of certain equity securities. The new standard was effective for us on January 1, 2018. The standard required modified retrospective application, with the exception of certain aspects of the standard that required prospective application. We adopted this standard on January 1, 2018, using primarily a retrospective approach. Due to regulatory accounting treatment, the adoption of this standard did not have a material impact on our financial statements. See Notes 11 and 12 for disclosures relating to our investments in debt and equity securities.

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ASU 2016-15, Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments

In August 2016, a new accounting standard was issued that clarifies how entities should present certain specific cash flow activities on the statement of cash flows. The guidance is intended to eliminate diversity in practice in how entities classify these specific activities between cash flows from operating activities, investing activities and financing activities. The specific activities addressed include debt prepayments and extinguishment costs, proceeds from the settlement of insurance claims, proceeds from corporate owned life insurance policies, and other activities. The standard also addresses how entities should apply the predominance principle when a transaction includes separately identifiable cash flows. The new standard was effective for us, and was adopted on January 1, 2018, using a retrospective transition method. The adoption of this guidance did not have a significant impact on our financial statements, as either our statement of cash flow presentation is consistent with the new prescribed guidance or we do not have significant activities relating to the specific transactions that are addressed by the new standard.

ASU 2016-18, Statement of Cash Flows: Restricted Cash

In November 2016, a new accounting standard was issued that clarifies how restricted cash and restricted cash equivalents should be presented on the statement of cash flows. The new guidance requires entities to include restricted cash and restricted cash equivalents as a component of the beginning and ending cash and cash equivalent balances on the statement of cash flows. The new standard is effective for us, and was adopted on January 1, 2018, using a retrospective transition method. The adoption of this guidance did not impact our financial statements, as our holdings and activities designated as restricted cash and restricted cash equivalents at transition and in prior periods are insignificant.

ASU 2017-01, Business Combinations: Clarifying the Definition of a Business

In January 2017, a new accounting standard was issued that clarifies the definition of a business. This standard is intended to assist entities with evaluating whether a transaction should be accounted for as an acquisition (or disposal) of assets or a business. The definition of a business affects many areas of accounting including acquisitions, disposals, goodwill, and consolidation. The new standard was effective for us, and was adopted on January 1, 2018, using a prospective transition approach. This standard did not have an impact on our financial statements on the date of adoption.

ASU 2017-05, Other Income: Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets

In February 2017, a new accounting standard was issued that intended to clarify the scope of accounting guidance pertaining to gains and losses from the derecognition of nonfinancial assets, and to add guidance for partial sales of nonfinancial assets. The new standard was effective for us, and was adopted on January 1, 2018, using a modified retrospective transition approach. This standard did not have a significant impact on our financial statements on the date of adoption. On July 3, 2018, 4CA sold its 7% interest in Four Corners. The sale transaction was accounted for in accordance with the guidance in ASU 2017-05, see Note 8.

ASU 2017-07, Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, a new accounting standard was issued that modifies how plan sponsors present net periodic pension cost and net periodic postretirement benefit cost (net benefit costs). The presentation changes require net benefit costs to be disaggregated on the income statement by the various components that comprise

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these costs. Specifically, only the service cost component is eligible for presentation as an operating income item, and all other cost components are now presented as non-operating items. This presentation change must be applied retrospectively. Furthermore, the new standard only allows the service cost component to be eligible for capitalization. The change in capitalization requirements must be applied prospectively. The new guidance was effective for us on January 1, 2018.

We adopted this new accounting standard on January 1, 2018. As a result of adopting this standard we have presented the non-service cost components of net benefits costs in other income instead of operating income. Prior year non-service cost components have also been reclassified to conform to this new presentation. We elected to apply the practical expedient guidance. As such, prior period costs have been estimated based on amounts previously disclosed in our pension and other postretirement benefit plan notes. The changes impacting capitalization have been adopted prospectively. As such, upon adoption, we are no longer capitalizing a portion of the non-service cost components of net benefit costs.

In 2018, because the non-service cost components are a reduction to total benefit costs, we estimate this change will result in the capitalization of an additional $15 million of net benefit costs, with a corresponding increase to pretax income for the year. For the three and nine months ended September 30, 2018, this change increased pre-tax income by approximately $4 million and $11 million respectively. See Note 5.

ASU 2018-02, Income Statement-Reporting Comprehensive Income: Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income

In February 2018, new accounting guidance was issued that allows entities an optional election to reclassify the income tax effects of the Tax Act on items within accumulated other comprehensive income to retained earnings. Amounts eligible for reclassification must relate to the effects from the Tax Act remaining in accumulated other comprehensive income. The new guidance also requires expanded disclosures. This guidance is effective for us on January 1, 2019 with early application permitted. The guidance should be applied either in the period of adoption or retrospectively to each period in which the effect of the

Tax Act was recognized.

We early adopted this guidance in the quarter ended March 31, 2018, and we have elected to reclassify the income tax effects of the Tax Act related to other comprehensive income activities to retained earnings. As of September 30, 2018, on a consolidated basis our accumulated other comprehensive income decreased $9 million, and APS's accumulated other comprehensive income decreased $5 million, as a result of adopting this guidance. Amounts were reclassified from accumulated other comprehensive income to retained earnings, and related to tax rate changes. The adoption of this guidance did not impact our income from continuing operations. See Note 15.

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Standards Pending Adoption

ASU 2016-02, Leases

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

We plan on adopting this standard, and related amendments, on January 1, 2019. We plan to elect the transition method that allows us to apply the guidance on the date of adoption and will not retrospectively adjust prior periods. We also plan on electing certain transition practical expedients that would allow us to not reassess (a) whether any expired or existing contracts are or contain leases, (b) the lease classification for any expired or existing leases and (c) initial direct costs for any existing leases. These practical expedients will apply to leases that commenced prior to January 1, 2019. Furthermore, we plan to elect the practical expedient transition provisions relating to the treatment of existing land easements. Our evaluation of this new accounting standard and the impacts it will have on our financial statements is on-going. The adoption of the new standard will result in the recognition of certain operating lease arrangements on our Consolidated Balance Sheets. We are currently evaluating the significance of the balance sheet impacts, and the impacts, if any, the lease guidance will have on our other financial statements. Our evaluation includes assessing leasing activities, implementing new processes and procedures, and preparing the expanded lease disclosures.

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

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

ASU 2017-12, Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities

In August 2017, a new accounting standard was issued that modifies hedge accounting guidance with the intent of simplifying the application of hedge accounting. The new standard is effective for us on January 1, 2019, with early application permitted. At transition the guidance requires the changes to be applied to hedging relationships existing on the date of adoption, with the effect of adoption reflected as of the beginning of the fiscal year of adoption using a cumulative effect adjustment approach. The presentation and disclosure changes may be applied prospectively. We are currently evaluating the new guidance, but at this time we d

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o not expect the adoption of this guidance will have a significant impact on our financial statements, as we are currently not applying hedge accounting.

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

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

14. Changes in Accumulated Other Comprehensive Loss

The following table shows the changes in Pinnacle West's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the three and nine months ended September 30, 2018 and 2017 (dollars in thousands):

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Three Months Ended September 30					
Balance June 30, 2018	$ (54,233)		$ (2,391)		$ (56,624)
Amounts reclassified from accumulated other comprehensive loss	1,099	(a)	451	(b)	1,550
Balance September 30, 2018	$ (53,134)		$ (1,940)		$ (55,074)

Balance June 30, 2017	$ (39,881)	$ (3,745)	$ (43,626)
OCI (loss) before reclassifications	—	9	9
Amounts reclassified from accumulated other comprehensive loss	790 (a)	710 (b)	1,500
Balance September 30, 2017	$ (39,091)	$ (3,026)	$ (42,117)

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COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Nine Months Ended September 30					
Balance December 31, 2017	$ (42,440)		$ (2,562)		$ (45,002)
OCI (loss) before reclassifications	(5,928)		(96)		(6,024)
Amounts reclassified from accumulated other comprehensive loss	3,188	(a)	1,316	(b)	4,504
Reclassification of income tax effect related to tax reform	(7,954)		(598)		(8,552)
Balance September 30, 2018	$ (53,134)		$ (1,940)		$ (55,074)
Balance December 31, 2016	$ (39,070)		$ (4,752)		$ (43,822)
OCI (loss) before reclassifications	(2,157)		(754)		(2,911)
Amounts reclassified from accumulated other comprehensive loss	2,136	(a)	2,480	(b)	4,616
Balance September 30, 2017	$ (39,091)		$ (3,026)		$ (42,117)

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

(b) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 7.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the changes in APS's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the three and nine months ended September 30, 2018 and 2017 (dollars in thousands):

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Three Months Ended September 30					
Balance June 30, 2018	$ (32,768)		$ (2,391)		$ (35,159)
Amounts reclassified from accumulated other comprehensive loss	952	(a)	451	(b)	1,403
Balance September 30, 2018	$ (31,816)		$ (1,940)		$ (33,756)
Balance June 30, 2017	$ (21,367)		$ (3,745)		$ (25,112)
OCI (loss) before reclassifications	—		9		9
Amounts reclassified from accumulated other comprehensive loss	777	(a)	710	(b)	1,487
Balance September 30, 2017	$ (20,590)		$ (3,026)		$ (23,616)

	Pension and Other Postretirement Benefits		Derivative Instruments		Total
Nine Months Ended September 30					
Balance December 31, 2017	$ (24,421)		$ (2,562)		$ (26,983)
OCI (loss) before reclassifications	(5,791)		(96)		(5,887)
Amounts reclassified from accumulated other comprehensive loss	2,836	(a)	1,316	(b)	4,152
Reclassification of income tax effect related to tax reform	(4,440)		(598)		(5,038)
Balance September 30, 2018	$ (31,816)		$ (1,940)		$ (33,756)
Balance December 31, 2016	$ (20,671)		$ (4,752)		$ (25,423)
OCI (loss) before reclassifications	(2,121)		(754)		(2,875)
Amounts reclassified from accumulated other comprehensive loss	2,202	(a)	2,480	(b)	4,682
Balance September 30, 2017	$ (20,590)		$ (3,026)		$ (23,616)

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

(b) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 7.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

15. Income Taxes

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 to 21% effective January 1, 2018. As a result of this rate reduction, the Company recognized a $1.14 billion reduction in its net deferred income tax liabilities as of December 31, 2017.

In accordance with accounting for regulated companies, the effect of this rate reduction is substantially offset by a net regulatory liability. As of December 31, 2017, to reflect the $1.14 billion reduction in its net deferred income tax liabilities caused by the rate reduction, APS has recorded a net regulatory liability of $1.52 billion and a new $377 million net deferred tax asset. The Company will amortize the net regulatory liability in accordance with applicable federal income tax laws, which require the amortization of a majority of the balance over the remaining regulatory life of the related property. As a result of the modifications made to the annual transmission formula rate during the second quarter, the Company has recorded amortization of FERC jurisdictional net excess deferred tax liabilities, retroactive to January 1, 2018. The Company continues to work with the ACC on a plan to amortize the remaining net excess deferred tax liabilities subject to its jurisdiction. See Note 4 for more details.

Several sections of the Tax Act contain technical ambiguities. Management has recognized tax positions which it believes are more likely than not to be sustained upon examination based upon its interpretation of this legislation.

In August 2018, Treasury proposed regulations that would clarify bonus depreciation rules under the Tax Act for property placed in service after September 27, 2017. During the third quarter the Company recorded deferred tax liabilities of approximately $11 million and an increase in its net regulatory liability for excess deferred taxes of approximately $9 million, primarily related to bonus depreciation benefits claimed on the Company’s 2017 tax return as a result of this clarifying guidance.

Additional clarifying guidance may be issued through additional legislation, Treasury regulations, or other technical guidance, which may impact the income tax effects of the Tax Act as recorded by the Company. As of September 30, 2018, the Company does not have a reasonable estimate of what the income tax effects of additional clarifying guidance may be.

For the quarter ending March 31, 2018, the Company early adopted ASU 2018-02, Income Statement-Reporting Comprehensive Income: Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income and elected to reclassify the income tax effects of the Tax Act on items within accumulated other comprehensive income to retained earnings. See Note 13 for additional information.

Net income associated with the Palo Verde sale leaseback VIEs is not subject to tax (see Note 6). As a result, there is no income tax expense associated with the VIEs recorded on the Pinnacle West Condensed Consolidated and APS Condensed Consolidated Statements of Income.

As of the balance sheet date, the tax year ended December 31, 2015 and all subsequent tax years remain subject to examination by the IRS. With a few exceptions, we are no longer subject to state income tax examinations by tax authorities for years before 2013.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The following discussion should be read in conjunction with Pinnacle West's Condensed Consolidated Financial Statements and APS's Condensed Consolidated Financial Statements and the related Combined Notes that appear in Item 1 of this report. For information on factors that may cause our actual future results to differ from those we currently seek or anticipate, see "Forward-Looking Statements" at the front of this report and "Risk Factors" in Part 1, Item 1A of the 2017 Form 10-K.

OVERVIEW

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

Areas of Business Focus

Operational Performance, Reliability and Recent Developments.

Nuclear. APS operates and is a joint owner of Palo Verde. Palo Verde experienced strong performance throughout the first three quarters of 2018. The April 2018 scheduled refueling outage was completed in 28 days, 13 hours, the shortest duration refueling outage in Palo Verde history.

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

Cholla

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

Four Corners

Asset Purchase Agreement and Coal Supply Matters. On December 30, 2013, APS purchased SCE's 48% interest in each of Units 4 and 5 of Four Corners. The final purchase price for the interest was approximately $182 million. In connection with APS's prior general retail rate case with the ACC, the ACC reserved the right to review the prudence of the Four Corners transaction for cost recovery purposes upon the closing of the transaction. On December 23, 2014, the ACC approved rate adjustments related to APS's acquisition of SCE's interest in Four Corners resulting in a revenue increase of $57.1 million on an annual basis. This decision was appealed and, on September 26, 2017, the Court of Appeals affirmed the ACC's decision on the Four Corners rate adjustment.

Concurrently with the closing of the SCE transaction described above, BHP Billiton New Mexico Coal, Inc. ("BHP Billiton"), the parent company of BHP Navajo Coal Company ("BNCC"), the coal supplier and operator of the mine that served Four Corners, transferred its ownership of BNCC to NTEC, a company formed by the Navajo Nation to own the mine and develop other energy projects. Also occurring concurrently with the closing, the Four Corners' co-owners executed the 2016 Coal Supply Agreement for the supply of coal to Four Corners from July 2016 through 2031. El Paso, a 7% owner in Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS agreed to assume the 7% shortfall obligation. (See Note 8 for a discussion of an arbitration related to the 2016 Coal Supply Agreement and an advance purchase of coal inventory made under the agreement.) On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El

Paso’s 7% interest in each of Units 4 and 5 of Four Corners. 4CA purchased the El Paso interest on July 6, 2016. The purchase price was immaterial in amount, and 4CA assumed El Paso's reclamation and decommissioning obligations associated with the 7% interest.
NTEC had the option to purchase the 7% interest within a certain timeframe pursuant to an option granted to NTEC. On December 29, 2015, NTEC provided notice of its intent to exercise the option. The purchase did not occur during the originally contemplated timeframe. Concurrent with the settlement of the 2016 Coal Supply Agreement matter described in Note 8, NTEC and 4CA agreed to allow for the purchase by NTEC of the 7% interest, consistent with the option. On June 29, 2018, 4CA and NTEC entered into an asset purchase agreement providing for the sale to NTEC of 4CA's 7% interest in Four Corners. Completion of the sale was subject to the receipt of approval by FERC, which was received on July 2, 2018, and the sale transaction closed on July 3, 2018. NTEC purchased the 7% interest at 4CA’s book value, approximately $70 million, and will pay 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note. In connection with the sale, Pinnacle West guaranteed certain obligations that NTEC will have to the other owners of Four Corners, such as NTEC's 7% share of capital expenditures and operating and maintenance expenses. Pinnacle West's guarantee is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement.

The 2016 Coal Supply Agreement contained alternate pricing terms for the 7% interest in the event NTEC did not purchase the interest. Until the time that NTEC purchased the 7% interest, the alternate pricing provisions were applicable to 4CA as the holder of the 7% interest. These terms included a formula under which NTEC must make certain payments to 4CA for reimbursement of operations and maintenance costs and a specified rate of return, offset by revenue generated by 4CA's power sales. Such payments are due to 4CA at the end of each calendar year. A $10 million payment was due to 4CA at December 31, 2017, which NTEC satisfied by directing to 4CA a prepayment from APS of a portion of a future mine reclamation obligation. The balance of the amount under this formula at September 30, 2018 for the calendar year 2017 is approximately $20 million, which is due to 4CA at December 31, 2018. The balance of the amount under this formula at September 30, 2018 for the calendar year 2018 (up to the date that NTEC purchased the 7% interest) is approximately $10 million, which is due to 4CA at December 31, 2019.

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

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

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

Wastewater Permit. On July 16, 2018, several environmental groups filed a petition for review before the EPA EAB concerning the NPDES wastewater discharge permit for Four Corners, which was reissued on June 12, 2018. The environmental groups allege that the permit was reissued in contravention of several requirements under the Clean Water Act and did not contain required provisions concerning EPA's 2015 revised effluent limitation guidelines for steam-electric EGUs, 2014 existing-source regulations governing cooling-water intake structures, and effluent limits for surface seepage and subsurface discharges from coal-ash disposal facilities. These groups are seeking to have the permit remanded back to EPA for revision to address these allegations. At this time, we cannot predict whether this EAB permit appeal will be successful, and if so whether the results of those proceedings will have a material impact on our financial position, results of operations or cash flows.

Navajo Plant

The co-owners of the Navajo Plant and the Navajo Nation agreed that the Navajo Plant will remain in operation until December 2019 under the existing plant lease. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017 that will allow for decommissioning activities to begin after the plant ceases operations in December 2019. Various stakeholders including regulators, tribal representatives, the plant's coal supplier and the 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 current owners of the Navajo Plant will cease operations in December 2019.

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

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.

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

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

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

Energy Storage. APS deploys a number of advanced technologies on its system, including energy storage. Storage can provide capacity, improve power quality, be utilized for system regulation, integrate renewable generation, and can be used to defer certain traditional infrastructure investments. Battery storage can also aid in integrating higher levels of renewables by storing excess energy when system demand is low and renewable production is high and then releasing the stored energy during peak demand hours later in the day and after sunset. APS is utilizing grid-scale battery storage projects to evaluate the potential benefits for customers and further our understanding of how storage works with other advanced technologies and the grid. We are preparing for additional battery storage in the future. In early 2018, APS entered into a 15-year power purchase agreement for a 65 MW solar facility that charges a 50 MW solar-fueled battery. Service under this agreement is scheduled to begin in 2021. (See “Renewable Energy” below.) APS recently issued a request for proposal for up to 106 MW of battery storage to be located at up to five of its AZ Sun sites. We are currently reviewing the bid submissions and anticipate such facilities could be in service by mid-2020.

Regulatory Matters

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

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates 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 of5.74% (the average annual bill impact for a typical APS residential customer was 7.96%). See Note 4 for details regarding the principal provisions of APS's application.

On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, the Residential Utility Consumer Office, limited income advocates and private rooftop solar organizations signed the 2017 Settlement Agreement and filed it with the ACC. The average annual customer bill impact under the 2017 Settlement Agreement was calculated as an increase of 3.28% (the average annual bill impact for a typical APS residential customer was calculated as 4.54%). (See Note 4 for details of the 2017 Settlement Agreement.)

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

On October 17, 2017, Warren Woodward (an intervener in APS's general retail rate case) filed a Notice of Appeal in the Arizona Court of Appeals, Division One. The notice raises a single issue related to the application of certain rate schedules to new APS residential customers after May 1, 2018. Mr. Woodward filed a second notice of appeal on November 13, 2017 challenging APS's $5 per month automated metering infrastructure opt-out program. Mr. Woodward's two appeals have been consolidated, and APS requested and was granted intervention. Mr. Woodward filed his opening brief on March 28, 2018. The ACC and APS filed responsive briefs on June 21, 2018. The Arizona Court of Appeals conferenced this matter on October 17, 2018, and APS anticipates a decision from the Arizona Court of Appeals by the end of 2018 or within the first half of 2019; however, the Arizona Court of Appeals is under no deadline to rule within a certain time period. 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 and not a request for rehearing. Arizona Revised Statute §40-246 requires the ACC to hold a hearing regarding any complaint alleging that a public service corporation is in violation of any commission order or that the rates being charged are not just and reasonable if the complaint is signed by at least twenty-five customers of the public service corporation. The Complaint alleged that APS is "in violation of commission order" [sic]. On February 13, 2018, the complainant filed an amended Complaint alleging that the rates and charges in the 2017 Rate Case Decision are not just and reasonable. The complainant requested that the ACC hold a hearing on the amended Complaint to determine if the average bill impact on residential customers of the rates and charges approved in the 2017 Rate Case Decision is greater than 4.54% (the average annual bill impact for a typical APS residential customer estimated by APS) and, if so, what effect the alleged greater bill impact has on APS's revenues and the overall reasonableness and justness of APS's rates and charges, in order to determine if there is sufficient evidence to warrant a full-scale rate hearing. The ACC held a hearing on this matter beginning in September 2018 and the hearing was concluded on October 1, 2018. The parties filed the initial briefs in October 2018 and reply briefs are due on November 16, 2018. APS expects a recommended opinion and order from the judge within the first quarter of 2019. APS cannot predict the outcome of this matter.

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

SCR Cost Recovery. On December 29, 2017, in accordance with the 2017 Rate Case Decision, APS filed a Notice of Intent to file its SCR Adjustment to permit recovery of costs associated with the installation of SCR equipment at Four Corners Units 4 and 5. APS filed the SCR Adjustment request in April 2018. Consistent with the 2017 Rate Case Decision, the request was narrow in scope and addressed only costs associated with this specific environmental compliance equipment. The SCR Adjustment request provided that there would be a $67.5 million annual revenue impact that would be applied as a percentage of base rates for all applicable customers. Also, as provided for in the 2017 Rate Case Decision, APS requested that the adjustment become effective no later than January 1, 2019. The hearing for this matter occurred in September 2018. At the hearing, APS accepted ACC Staff's recommendation of a lower annual revenue impact of approximately $58.5 million. A decision in this matter is expected early in the first quarter of 2019.

Renewable Energy. The ACC approved the RES in 2006. The renewable energy requirement is 8% of retail electric sales in 2018 and increases annually until it reaches 15% in 2025. In APS’s 2009 general retail rate case settlement agreement, APS agreed to exceed the RES standards, committing to use APS’s best efforts to have 1,700 gigawatt-hours of new renewable resources in service by year-end 2015, in addition to its RES renewable resource commitments. APS met its settlement commitment and overall RES target for 2017. A component of the RES targets development of distributed energy systems.

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 three-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. On June 12, 2018, the ACC approved the 2018 RES Implementation Plan.

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

In September 2016, the ACC initiated a proceeding which will examine the possible modernization and expansion of the RES. On January 30, 2018, ACC Commissioner Tobin proposed a plan in this proceeding which would broaden the RES to include a series of energy policies tied to clean energy sources (the "Energy Modernization Plan"). The Energy Modernization Plan includes replacing the current RES standard with a new standard called the Clean Resource Energy Standard and Tariff ("CREST"), which incorporates the proposals in the Energy Modernization Plan. A set of draft CREST rules for the ACC's consideration was issued by Commissioner Tobin's office on July 5, 2018. See Note 4 for more information on the RES and the Energy Modernization Plan.

The following table summarizes renewable energy sources in APS's renewable portfolio that are in operation and under development as of September 30, 2018.

	Net Capacity in Operation (MW)	**Net Capacity Planned / Under Development (MW)**
Total APS Owned: Solar	239	—
Purchased Power Agreements:		
Solar	310	—
Solar + Energy Storage	—	50
Wind	289	—
Geothermal	10	—
Biomass	14	—
Biogas	6	—
Total Purchased Power Agreements	629	50
Total Distributed Energy: Solar (a)	815	60 (b)
Total Renewable Portfolio	1,683	110

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

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

Demand Side Management. In December 2009, Arizona regulators placed an increased focus on energy efficiency and other demand side management programs to encourage customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. The ACC initiated an Energy Efficiency rulemaking, with a proposed Electric Energy Efficiency Standard of 22%

cumulative annual energy savings by 2020. The 22% figure represents the cumulative reduction in future energy usage through 2020 attributable to energy efficiency initiatives. This standard became effective on January 1, 2011.

On June 1, 2016, APS filed its 2017 DSM Implementation 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 Implementation Plan was $62.6 million. On January 27, 2017, APS filed an updated and modified 2017 DSM Implementation Plan that incorporated the proposed $4 million Residential Demand Response, Energy Storage and Load Management Program that was filed with the ACC on December 5, 2016 and requested that the budget for the 2017 DSM Implementation Plan be increased to $66.6 million. On August 15, 2017, the ACC approved the amended 2017 DSM Implementation Plan.

On September 1, 2017, APS filed its 2018 DSM Implementation 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 Implementation 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 Implementation Plan, which revised the allocations between budget items to address customer participation levels, but kept the overall budget at $52.6 million. The ACC has not yet ruled on the APS 2018 amended DSM Plan. See Note 4 for more information on demand side management.

Tax Expense Adjustor Mechanism 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 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.

On August 13, 2018, APS filed a second request with the ACC to return an additional $86.5 million in tax savings to customers, starting January 1, 2019. This second request addresses amortization of non-depreciation related excess deferred taxes previously collected from customers. Additionally, as part of this second request, APS informed the ACC of its intent to file a third future request to address the amortization of depreciation related excess deferred taxes, as the Company is currently seeking IRS guidance regarding the amortization method and period it should apply to these depreciation related excess deferred taxes. The ACC has not yet approved this request.

The TEAM expressly applies to APS's retail rates with the exception noted above. As discussed in Note 4, FERC issued an order on May 22, 2018 authorizing APS to provide for the cost reductions resulting from the income tax changes in its wholesale transmission rates.

See Note 4 for additional details.

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, an 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 opinion and order by a 4-1 vote. As a result of the ACC's action, effective with APS's 2017 Rate Case Decision, the net metering tariff that governs payments for energy exported to the grid from residential rooftop solar systems was replaced by a more formula-driven approach that utilizes inputs from historical wholesale solar power until an avoided cost methodology is developed by the ACC.

As amended, the decision provides that payments by utilities for energy exported to the grid from DG solar facilities will be determined using a resource comparison proxy methodology, a method that is based on the most recent five-year rolling average price that APS pays for utility-scale solar projects, while a forecasted avoided cost methodology is being developed. The price established by this resource comparison proxy 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 general retail 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
-

Once an export price is set for APS, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future general retail rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies. A first-year export energy price of 12.9 cents per kWh is included in the 2017 Settlement Agreement and became effective on August 19, 2017.

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

On January 23, 2017, 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 amended complaint. On February 15, 2018, the Superior Court dismissed Commissioner Burns' amended complaint. On March 6, 2018, Commissioner Burns filed an objection to the proposed final order from the Superior Court and a motion to further amend his complaint. The Superior Court permitted Commissioner Burns to amend his complaint to add a claim regarding his attempted investigation into whether his fellow commissioners should have been disqualified from voting on APS's 2017 rate case. Commissioner Burns has now served his second amended complaint, and responsive filings were due on June 25, 2018. All defendants filed responses opposing the second amended complaint and requested that it be dismissed. Oral argument is scheduled for November 13, 2018 regarding the motion to dismiss. APS and Pinnacle West cannot predict the outcome of this matter.

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

Arizona elections ballot. On November 6, 2018, the initiative failed to receive adequate voter support and was defeated.

Energy Modernization Plan. On January 30, 2018, ACC Commissioner Tobin proposed the Energy Modernization Plan, which consists of a series of energy policies tied to clean energy sources such as energy storage, biomass, energy efficiency, electric vehicles, and expanded energy planning through the integrated resource plans ("IRP") process. The Energy Modernization Plan includes replacing the current RES standard with a new standard called the CREST, which incorporates the proposals in the Energy Modernization Plan. On 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. On July 5, 2018, Commissioner Tobin's office issued a set of draft CREST rules for the ACC's consideration.

In August 2018, the ACC directed ACC Staff to open a new rulemaking docket which will address a wide range of energy issues, including the Energy Modernization Plan proposals. The rulemaking will consider possible modifications to existing ACC rules, such as the Renewable Energy Standard, Electric and Gas Energy Efficiency Standards, Net Metering, Resource Planning, and the Biennial Transmission Assessment, as well as the development of new rules regarding forest bioenergy, electric vehicles, interconnection of distributed generation, baseload security, blockchain technology and other technological developments, retail competition, and other energy-related topics. No additional action has been taken in this rulemaking docket to date. APS cannot predict the outcome of this matter.

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

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

Appeals for the Ninth Circuit on December 4, 2017. That proceeding is pending and APS cannot predict the outcome of the proceeding.

Financial Strength and Flexibility

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

Other Subsidiaries

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

On March 29, 2016, TransCanyon entered into a strategic alliance agreement with Pacific Gas and Electric Company ("PG&E") to jointly pursue competitive transmission opportunities solicited by the CAISO, the operator for the majority of California's transmission grid. TransCanyon and PG&E intend to jointly engage in the development of future transmission infrastructure and compete to develop, build, own and operate transmission projects approved by the CAISO.

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

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

Key Financial Drivers

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

Electric Operating Revenues. For the years 2015 through 2017, retail electric revenues comprised approximately 95% of our total electric operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, distributed energy additions, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery mechanisms. These revenue transactions are affected by the availability of excess generation or other energy resources and wholesale market conditions, including competition, demand and prices.

Actual and Projected Customer and Sales Growth. Retail customers in APS's service territory increased 1.6% for the nine-month period ended September 30, 2018 compared with the prior-year period. For the three years 2015 through 2017, APS's customer growth averaged 1.5% per year. We currently project annual customer growth to be 1.5 - 2.5% for 2018 and to average in the range of 2 - 3% for 2018 through 2020 based on our assessment of improving economic conditions in Arizona.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 0.1% for the nine-month period ended September 30, 2018 compared with the prior-year period. Improving economic conditions and customer growth were offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives. For the three years 2015 through 2017, APS experienced annual increases in retail electricity sales averaging 0.2%, adjusted to exclude the effects of weather variations. We currently project that annual retail electricity sales in kWh will increase in the range of 0 - 1% for 2018 and increase on average in the range of 0.5 - 1.5% during 2018 through 2020, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. A slower recovery of the Arizona economy or acceleration of the expected effects of customer conservation, energy efficiency or distributed renewable generation initiatives could further impact these estimates.

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

Weather. In forecasting the retail sales growth numbers provided above, we assume normal weather patterns based on historical data. Historically, extreme weather variations have resulted in annual variations in net income in excess of $20 million. However, our experience indicates that the more typical variations from normal weather can result in increases or decreases in annual net income of up to $10 million.

Fuel and Purchased Power Costs. Fuel and purchased power costs included on our Condensed Consolidated Statements of Income are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, transmission availability or constraints, prevailing market prices, new generating plants being placed in service in our market areas, changes in our generation resource allocation, our hedging program for managing such costs and PSA deferrals and the related amortization.

Operations and Maintenance Expenses. Operations and maintenance expenses are impacted by customer and sales growth, power plant operations, maintenance of utility plant (including generation, transmission, and distribution facilities), inflation, unplanned outages, planned outages (typically scheduled in the spring and fall), renewable energy and demand side management related expenses (which are offset by the same amount of operating revenues) and other factors. See Note 13 for discussion in new accounting guidance related to the presentation of net periodic pension and postretirement benefit costs.

Depreciation and Amortization Expenses. Depreciation and amortization expenses are impacted by net additions to utility plant and other property (such as new generation, transmission, and distribution facilities), and changes in depreciation and amortization rates. See "Liquidity and Capital Resources" below for information regarding the planned additions to our facilities and income tax impacts related to bonus depreciation.

Pension and other postretirement non-service credits - net. Pension and other postretirement non-service credits can be impacted by changes in our actuarial assumptions. The most relevant actuarial assumptions are the discount rate used to measure our net periodic costs/credit, the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term, the mortality assumptions and the assumed healthcare cost trend rates. We review these assumptions on an annual basis and adjust them as necessary. See Note 13 for discussion of new accounting guidance related to the presentation of net periodic pension and postretirement benefit costs.

Property Taxes. Taxes other than income taxes consist primarily of property taxes, which are affected by the value of property in-service and under construction, assessment ratios, and tax rates. The average property tax rate in Arizona for APS, which owns essentially all of our property, was 11.2% of the assessed value for 2017, 11.2% for 2016 and 11.0% for 2015. We expect property taxes to increase as we add new generating units and continue with improvements and expansions to our existing generating units and transmission and distribution facilities.

Income Taxes. Income taxes are affected by the amount of pretax book income, income tax rates, certain deductions and non-taxable items, such as AFUDC. In addition, income taxes may also be affected by the settlement of issues with taxing authorities. On December 22, 2017, the Tax Act was enacted and is generally effective on January 1, 2018. Changes which will impact the Company include a reduction in the corporate tax rate to 21%, revisions to the rules related to tax bonus depreciation, limitations on interest deductibility and an associated exception for certain public utilities, and requirements that certain excess deferred tax amounts of regulated utilities be normalized. (See Note 15 for details of the impacts on the Company as of December 31, 2017.) In APS's recent general retail rate case, the ACC approved a Tax Expense Adjustor Mechanism which will be used to pass through the income tax effects to retail customers of the Tax Act. (See Note 4 for details of the TEAM.)

Interest Expense. Interest expense is affected by the amount of debt outstanding and the interest rates on that debt (see Note 3). The primary factors affecting borrowing levels are expected to be our capital expenditures, long-term debt maturities, equity issuances and internally generated cash flow. An allowance for borrowed funds used during construction offsets a portion of interest expense while capital projects are under construction. We stop accruing AFUDC on a project when it is placed in commercial operation.

RESULTS OF OPERATIONS

Pinnacle West's only reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electric service to Native Load customers) and related activities and includes electricity generation, transmission and distribution.

Operating Results – Three-month period ended September 30, 2018 compared with three-month period ended September 30, 2017.

Our consolidated net income attributable to common shareholders for the three months ended September 30, 2018 was $315 million, compared with consolidated net income attributable to common shareholders of $276 million for the prior-year period. The results reflect an increase of approximately $38 million for the regulated electricity segment primarily due to the effects of weather and lower federal income tax rates, net of the related customer refunds. These increases were partially offset by higher operations and maintenance primarily due to an increase in public outreach costs associated with the ballot initiative and higher depreciation and amortization primarily due to increased depreciation rates and plant in service.

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

	Three Months Ended September 30, 2018	2017	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$877	$869	$ 8
Operations and maintenance	(246)	(229)	(17)
Depreciation and amortization	(146)	(134)	(12)
Taxes other than income taxes	(51)	(45)	(6)
Pension and other postretirement non-service credits - net	12	7	5
All other income and expenses, net	14	7	7
Interest charges, net of allowance for borrowed funds used during construction	(56)	(50)	(6)
Income taxes	(85)	(144)	59
Less income related to noncontrolling interests (Note 6)	(5)	(5)	—
Regulated electricity segment income	314	276	38
All other	1	—	1
Net Income Attributable to Common Shareholders	$315	$276	$ 39

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Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $8 million higher for the three months ended September 30, 2018 compared with the prior-year period. The following table summarizes the major components of this change:

	Increase (Decrease)		
	Operating revenues	**Fuel and purchased power expenses**	**Net change**
	(dollars in millions)		
Effects of weather	$44	$ 10	$ 34
Impacts of retail regulatory settlement effective August 19, 2017 (Note 4)			
Increase in net retail base rates	30	—	30
Change in residential rate design and seasonal rates (a)	(28)	—	(28)
Higher transmission revenues (Note 4)	8	—	8
Refunds due to lower Federal corporate income tax rate (Note 4)	(51)	—	(51)
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	70	69	1
Higher retail revenue due to higher customer growth and changes in customer usage patterns partially offset by the impacts of energy efficiency and distributed generation	13	3	10
Miscellaneous items, net	3	(1)	4
Total	$89	$ 81	$ 8

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

Operations and maintenance. Operations and maintenance expenses increased $17 million for the three months ended September 30, 2018 compared with the prior-year period primarily because of:

- An increase of $13 million related to public outreach costs at the parent company primarily associated with the ballot initiative (see Note 4);

- An increase of $5 million in transmission, distribution, and customer service costs primarily due to maintenance costs;

- An increase of $3 million for costs related to information technology;
- An increase of $3 million to inform customers about APS's clean energy focus;

- A decrease of $4 million related to employee benefit cost; and

- A decrease of $3 million related to miscellaneous other factors.

Depreciation and amortization. Depreciation and amortization expenses were $12 million higher for the three months ended September 30, 2018 compared with the prior-year period primarily related to increased depreciation and amortization rates of $9 million and increased plant in service of $3 million.

Taxes other than income taxes. Taxes other than income taxes were $6 million higher for the three months ended September 30, 2018 compared with the prior-year period primarily due to higher property values and the amortization of our property tax deferral regulatory asset.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $5 million higher for the three months ended September 30, 2018 compared to the prior-year period primarily due to higher market returns and the adoption of new pension and other postretirement accounting guidance in 2018 (see Notes 5 and 13).

All other income and expenses, net. All other income and expenses, net were $7 million higher for the three months ended September 30, 2018 compared with the prior-year period primarily due to the debt return on the Four Corners SCR deferrals (Note 4).

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction, were $6 million higher for the three months ended September 30, 2018 compared with the prior-year period primarily due to higher debt balances in the current period.

Income taxes. Income taxes were $59 million lower for the three months ended September 30, 2018 compared with the prior-year period primarily due to the effects of the federal tax reform and lower pretax income in the current year period.

Operating Results – Nine-month period ended September 30, 2018 compared with nine-month period ended September 30, 2017.

Our consolidated net income attributable to common shareholders for the nine months ended September 30, 2018 was $485 million, compared with consolidated net income attributable to common shareholders of $467 million for the prior-year period. The results reflect an increase of approximately $19 million for the regulated electricity segment primarily due to higher revenue resulting from the retail regulatory settlement effective August 19, 2017 and higher transmission revenues. These increases were partially offset by higher operations and maintenance resulting from increased planned outage costs, increased public outreach costs associated with the ballot initiative and higher depreciation and amortization primarily due to increased depreciation rates.

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

	Nine Months Ended September 30, 2018	2017	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$2,067	$2,012	$ 55
Operations and maintenance	(769)	(670)	(99)
Depreciation and amortization	(435)	(386)	(49)
Taxes other than income taxes	(158)	(132)	(26)
Pension and other postretirement non-service credits - net	37	20	17
All other income and expenses, net	46	19	27
Interest charges, net of allowance for borrowed funds used during construction	(162)	(147)	(15)
Income taxes	(127)	(236)	109
Less income related to noncontrolling interests (Note 6)	(15)	(15)	—
Regulated electricity segment income	484	465	19
All other	1	2	(1)
Net Income Attributable to Common Shareholders	$485	$467	$ 18

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $55 million higher for the nine months ended September 30, 2018 compared with the prior-year period. The following table summarizes the major components of this change:

	Increase (Decrease)		
	Operating revenues	**Fuel and purchased power expenses**	**Net change**
	(dollars in millions)		
Impacts of retail regulatory settlement effective August 19, 2017 (Note 4)			
Increase in net retail base rates	$104	$ —	$ 104
Change in residential rate design and seasonal rates (a)	(18)	—	(18)
Higher transmission revenues (Note 4)	26	—	26
Higher renewable energy regulatory surcharges and lower purchased power, partially offset in operations and maintenance costs	12	(6)	18
Effects of weather	8	—	8
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	100	90	10
Refunds due to lower Federal corporate income tax rate (Note 4)	(111)	—	(111)
Higher retail sales due to customer growth and changes in customer usage patterns and related pricing partially offset by the impacts of energy efficiency and distributed generation	9	—	9
Miscellaneous items, net	2	(7)	9
Total	$132	$ 77	$ 55

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

Operations and maintenance. Operations and maintenance expenses increased $99 million for the nine months ended September 30, 2018 compared with the prior-year period primarily because of:

- An increase of $28 million in fossil generation costs primarily due to higher planned outage and operating costs;

- An increase of $23 million primarily related to costs for renewable energy and similar regulatory programs, which are partially offset in operating revenues and purchased power;

- An increase of $24 million related to public outreach costs at the parent company primarily associated with the ballot initiative (see Note 4);

- An increase of $15 million in transmission, distribution, and customer service costs primarily due to maintenance costs;

- An increase of $9 million for costs related to information technology;
- An increase of $5 million to inform customers about APS's clean energy focus; and
- A decrease of $5 million related to the absence of the Navajo Plant capital projects canceled in 2017 due to expected plant retirement, which were deferred for regulatory recovery in depreciation.

Depreciation and amortization. Depreciation and amortization expenses were $49 million higher for the nine months ended September 30, 2018 compared with the prior-year period primarily related to increased depreciation and amortization rates of $38 million, increased plant in service of $6 million and the absence of the regulatory deferral of the canceled capital projects in 2017 associated with the expected Navajo Plant retirement of $5 million.

Taxes other than income taxes. Taxes other than income taxes were $26 million higher for the nine months ended September 30, 2018 compared with the prior-year period primarily due to higher property values and the amortization of our property tax deferral regulatory asset.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $17 million higher for the nine months ended September 30, 2018 compared to the prior-year period primarily due to higher market returns and the adoption of new pension and other postretirement accounting guidance in 2018 (see Notes 5 and 13).

All other income and expenses, net. All other income and expenses, net were $27 million higher for the nine months ended September 30, 2018 compared with the prior-year period primarily due to the debt return on the Four Corners SCR deferrals (Note 4) and increased allowance for equity funds used during construction.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction, were $15 million higher for the nine months ended September 30, 2018 compared with the prior-year period primarily due to higher debt balances in the current period.

Income taxes. Income taxes were $109 million lower for the nine months ended September 30, 2018 compared with the prior-year period primarily due to the effects of the federal tax reform and the effects of lower pretax income in the current year period.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

Our primary sources of cash are dividends from APS and external debt and equity issuances. An ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the related ACC order, the common equity ratio is defined as total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At September 30, 2018, APS's common equity ratio, as defined, was 53%. Its total shareholder equity was approximately $5.6 billion, and total capitalization was approximately $10.6 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $4.2 billion, assuming APS's total capitalization remains the same. This restriction does not materially affect Pinnacle West's ability to meet its ongoing cash needs or ability to pay dividends to shareholders.

APS's capital requirements consist primarily of capital expenditures and maturities of long-term debt. APS funds its capital requirements with cash from operations and, to the extent necessary, external debt financing and equity infusions from Pinnacle West.

On December 22, 2017, the Tax Act was enacted. As a result of this legislation, bonus depreciation is no longer available for regulated public utility company property acquired, or that commenced construction, after September 27, 2017. The final legislative language contains a transition rule for property which was acquired, or under construction, prior to September 28, 2017 which would allow at least some part of APS's capital projects under construction at that time to continue to qualify for bonus depreciation under pre-Act rules. However, because of current ambiguities regarding the scope of this transition rule, it is unclear how much of APS's capital projects which were under construction prior to September 28, 2017, will qualify. In August 2018, Treasury proposed regulations that would clarify bonus depreciation rules under the Tax Act for property placed in service after September 27, 2017. While the proposed regulations themselves are ambiguous with respect to property placed in service on or after January 1, 2018, the Company currently believes the continued availability of bonus depreciation for property under construction prior to September 28, 2017 will generate $100-$120 million of cash tax benefits in 2018 and 2019. Due to the ambiguities in the proposed regulations these cash tax benefits may change. The cash generated by bonus depreciation is an acceleration of the tax benefits that APS would have otherwise received over 20 years and reduces rate base for ratemaking purposes. At Pinnacle West Consolidated, when coupled with a lower 21 percent corporate tax rate, the continued availability of bonus depreciation to this transition period property is expected to delay until 2020 full cash realization of approximately $51 million of currently unrealized Investment Tax Credits and other tax credits, which are recorded as a deferred tax asset on the Condensed Consolidated Balance Sheets as of September 30, 2018.

Summary of Cash Flows

The following tables present net cash provided by (used for) operating, investing and financing activities for the nine months ended September 30, 2018 and 2017 (dollars in millions):

Pinnacle West Consolidated

	Nine Months Ended September 30, 2018	2017	Net Change
Net cash flow provided by operating activities	$960	$772	$188
Net cash flow used for investing activities	(913)	(1,040)	127
Net cash flow provided by financing activities	4	270	(266)
Net increase in cash and cash equivalents	$51	$2	$49

Arizona Public Service Company

	Nine Months Ended September 30, 2018	2017	Net Change
Net cash flow provided by operating activities	$988	$805	$183
Net cash flow used for investing activities	(906)	(1,018)	112
Net cash flow provided by (used for) financing activities	(31)	215	(246)
Net increase in cash and cash equivalents	$51	$2	$49

Operating Cash Flows

Nine-month period ended September 30, 2018 compared with nine-month period ended September 30, 2017. Pinnacle West's consolidated net cash provided by operating activities was $960 million in 2018 and $772 million in 2017. The increase of $188 million in net cash provided is primarily due to higher cash receipts from operating activities and lower other cash payments, partially offset by higher payments for operations and maintenance.

Retirement plans and other postretirement benefits. Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. The requirements of the Employee Retirement Income Security Act of 1974 ("ERISA") require us to contribute a minimum amount to the qualified plan. We contribute at least the minimum amount required under ERISA regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of plan assets and our pension benefit obligations. Under ERISA, the qualified pension plan was 117% funded as of January 1, 2018 and 115% as of January 1, 2017. Under GAAP, the qualified pension plan was 95% funded as of January 1, 2018 and 88% funded as of January 1, 2017. See Note 5 for additional details. The assets in the plan are primarily comprised of fixed-income, equity, real estate, and short-term investments. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We have made voluntary contributions of $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 $72 million for prior years retiree medical claims from the other postretirement benefit plan trust assets.

Investing Cash Flows

Nine-month period ended September 30, 2018 compared with nine-month period ended September 30, 2017. Pinnacle West's consolidated net cash used for investing activities was $913 million in 2018, compared to $1,040 million in 2017, a decrease of $127 million in net cash used primarily related to decreased capital expenditures. The difference between APS and Pinnacle West's net cash used for investing activities primarily relates to Pinnacle West cash payments for 4CA's capital expenditures.

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

Capital Expenditures
(dollars in millions)

	Estimated for the Year Ended December 31,		
	2018	**2019**	**2020**
APS			
Generation:			
Clean:			
Nuclear Fuel	$71	$72	$64
Nuclear Generation	70	70	68
Renewables	10	16	17
Environmental	80	30	43
New Gas Generation	119	13	—
Other Generation	168	108	115
Distribution	467	518	598
Transmission	147	201	167
Other (a)	74	125	139
Total APS	$1,206	$1,153	$1,211

(a) Primarily information systems and facilities projects.

Generation capital expenditures are comprised of various improvements to APS's existing fossil, renewable and nuclear plants. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment, such as turbines, boilers and environmental equipment. We are monitoring the status of certain environmental matters, which, depending on their final outcome, could require modification to our planned environmental expenditures.

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

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

Financing Cash Flows and Liquidity

Nine-month period ended September 30, 2018 compared with nine-month period ended September 30, 2017. Pinnacle West's consolidated net cash provided by financing activities was $4 million in 2018, compared to $270 million of net cash provided in 2017, a decrease of $266 million in net cash provided. The decrease in net cash provided by financing activities includes $254 million lower issuances of long-term debt and higher long-term debt repayments of $82 million through September 30, 2018, which are partially offset by $79 million of higher net short-term borrowings. The difference between APS and Pinnacle West's net cash provided by financing activities primarily relates to short-term borrowings and repayments at Pinnacle West on behalf of 4CA.

Significant Financing Activities. On October 18, 2018, the Pinnacle West Board of Directors declared a dividend of $0.7375 per share of common stock, payable on December 3, 2018 to shareholders of record on November 1, 2018. This represents an increase in the indicated annual dividend from $2.78 per share to $2.95 per share.

On May 30, 2018, APS purchased all $32 million of Maricopa County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds, 2009 Series C, due 2029. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2017.

On June 26, 2018, APS repaid at maturity APS's $50 million term loan facility.

On August 9, 2018, APS issued $300 million of 4.20% unsecured senior notes that mature on August 15, 2048. The net proceeds from the sale of the notes were used to repay commercial paper borrowings.

Available Credit Facilities. Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs.

On June 28, 2018, Pinnacle West refinanced its 364-day $125 million unsecured revolving credit facility that would have matured on July 30, 2018 with a new 364-day $150 million credit facility that matures June 27, 2019. Borrowings under the facility bear interest at LIBOR plus 0.70% per annum. At September 30, 2018, Pinnacle West had $79 million outstanding under the facility.

On July 12, 2018, Pinnacle West replaced its $200 million revolving credit facility that would have matured in

May 2021, with a new $200 million facility that matures in July 2023. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At September 30, 2018, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and $49 million of commercial paper borrowings.

On July 12, 2018, APS replaced its $500 million revolving credit facility that would have matured in May 2021, with a new $500 million facility that matures in July 2023.

At September 30, 2018, APS had two revolving credit facilities totaling $1 billion, including a $500 million credit facility that matures in June 2022 and the above-mentioned $500 million facility. 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 September 30, 2018, APS had no commercial paper outstanding and no outstanding borrowings or letters of credit under its revolving credit facilities.

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

Other Financing Matters. See Note 7 for information related to the change in our margin and collateral accounts.

Debt Provisions

Pinnacle West's and APS's debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with this covenant. For both Pinnacle West and APS, this covenant requires that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At September 30, 2018, the ratio was approximately 50% for Pinnacle West and 46% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could "cross-default" other debt. See further discussion of "cross-default" provisions below.

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

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

See Note 3 for further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of November 1, 2018 are shown below. We are disclosing these credit ratings to enhance understanding of our cost of short-term and long-term capital and our ability to access the markets for liquidity and long-term debt. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS's securities and/or result in an increase in the cost of, or limit access to, capital. Such revisions may also result in substantial additional cash or other collateral requirements related to certain derivative instruments, insurance policies, natural gas transportation, fuel supply, and other energy-related contracts. At this time, we believe we have sufficient available liquidity resources to respond to a downward revision to our credit ratings.

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

Off-Balance Sheets Arrangements

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

Contractual Obligations

For the nine months ended September 30, 2018, our fuel and purchased power commitments decreased approximately $166 million from amounts reported at December 31, 2017, primarily due to the amended and restated Four Corners 2016 Coal Supply Agreement effective in the second quarter of 2018. The majority of these changes relate to the years 2023 and thereafter.

Other than the items described above, there have been no material changes, as of September 30, 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.

CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with GAAP, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. There have been no changes to our critical accounting policies since our 2017 Form 10-K except for the adoption of the new pension and other postretirement accounting guidance as noted below. See "Critical Accounting Policies" in Item 7 of the 2017 Form 10-K for further details about our critical accounting policies.

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 and allows only the service cost component of periodic net benefit cost to be eligible for capitalization. (See Note 13 for additional information.)

OTHER ACCOUNTING MATTERS

We adopted the following new accounting standards on January 1, 2018:

- ASU 2014-09: Revenue from Contracts with Customers, and related amendments
- ASU 2016-01: Financial Instruments, Recognition and Measurement
- ASU 2016-15: Statement of Cash Flows, Classification of Certain Cash Receipts and Cash Payments
- ASU 2016-18: Statement of Cash Flows, Restricted Cash
- ASU 2017-01: Business Combinations, Clarifying the Definition of a Business
- ASU 2017-05: Other Income, Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets
- ASU 2017-07: Compensation-Retirement Benefits, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost
- ASU 2018-02: Income Statement-Reporting Comprehensive Income, Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income

We are currently evaluating the impacts of the pending adoption of the following new accounting standards:

-

- ASU 2016-02: Leases, and related amendments, effective for us on January 1, 2019
- ASU 2016-13: Financial Instruments, Measurement of Credit Losses, effective for us on January 1, 2020
- ASU 2017-12: Derivatives and Hedging, Targeted Improvements to Accounting for Hedging Activities, effective for us on January 1, 2019
- ASU 2018-15: Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract, effective for us on January 1, 2020

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

MARKET AND CREDIT RISKS

Market Risks

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

Interest Rate and Equity Risk

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

Commodity Price Risk

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

The following table shows the net pretax changes in mark-to-market of our derivative positions for the nine months ended September 30, 2018 and 2017 (dollars in millions):

	Nine Months Ended September 30,	
	2018	2017

Mark-to-market of net positions at beginning of year	$(91)	$(49)
Decrease (Increase) in regulatory asset/liability	12	(37)
Recognized in OCI:		
Mark-to-market losses realized during the period	2	2
Change in valuation techniques	—	—
Mark-to-market of net positions at end of period	$(77)	$(84)

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at September 30, 2018 by maturities and by the type of valuation that is performed to calculate the fair values, classified in their entirety based on the lowest level of input that is significant to the fair value measurement. See Note 1, "Derivative Accounting" and "Fair Value Measurements," in Item 8 of our 2017 Form 10-K and Note 11 for more discussion of our valuation methods.

Source of Fair Value	2018	2019	2020	2021	2022	Total fair value
Observable prices provided by other external sources	$(11)	$(38)	$(11)	$(7)	$—	$(67)
Prices based on unobservable inputs	—	(3)	(3)	—	(4)	(10)
Total by maturity	$(11)	$(41)	$(14)	$(7)	$(4)	$(77)

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management assets and liabilities included on Pinnacle West's Condensed Consolidated Balance Sheets at September 30, 2018 and December 31, 2017 (dollars in millions):

	September 30, 2018 Gain (Loss)		December 31, 2017 Gain (Loss)	
	Price Up 10%	Price Down 10%	Price Up 10%	Price Down 10%
Mark-to-market changes reported in:				
Regulatory asset (liability) or OCI (a)				
Electricity	$1	$ (1)	$1	$ (1)
Natural gas	35	(35)	45	(45)
Total	$36	$ (36)	$46	$ (46)

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

Credit Risk

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

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Item 4. CONTROLS AND PROCEDURES

(a) Disclosure Controls and Procedures

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

Pinnacle West's management, with the participation of Pinnacle West's Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of Pinnacle West's disclosure controls and procedures as of September 30, 2018. Based on that evaluation, Pinnacle West's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, Pinnacle West's disclosure controls and procedures were effective.

APS's management, with the participation of APS's Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of APS's disclosure controls and procedures as of September 30, 2018. Based on that evaluation, APS's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, APS's disclosure controls and procedures were effective.

(b) Changes in Internal Control Over Financial Reporting

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

No change in Pinnacle West's or APS's internal control over financial reporting occurred during the fiscal quarter ended September 30, 2018 that materially affected, or is reasonably likely to materially affect, Pinnacle West's or APS's internal control over financial reporting.

PART II -- OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

See "Business of Arizona Public Service Company — Environmental Matters" in Item 1 of the 2017 Form 10-K and Part II, Item 5 of the Pinnacle West/APS Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 with regard to pending or threatened litigation and other disputes.

See Note 4 for ACC and FERC-related matters.

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

Item 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A — Risk Factors in the 2017 Form 10-K, which could materially affect the business, financial condition, cash flows or future results of Pinnacle West and APS. The risks described in the 2017 Form 10-K are not the only risks facing Pinnacle West and APS. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect the business, financial condition, cash flows and/or operating results of Pinnacle West and APS.

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

(a) Exhibits

Exhibit No.	Registrant(s)	Description
31.1	Pinnacle West	Certificate of Donald E. Brandt, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
31.2	Pinnacle West	Certificate of James R. Hatfield, Executive Vice President and Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
31.3	APS	Certificate of Donald E. Brandt, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
31.4	APS	Certificate of James R. Hatfield, Executive Vice President and Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
32.1*	Pinnacle West	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	APS	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	Pinnacle West APS	XBRL Instance Document - the instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.
101.SCH	Pinnacle West APS	XBRL Taxonomy Extension Schema Document
101.CAL	Pinnacle West APS	XBRL Taxonomy Extension Calculation Linkbase Document

101.LAB	Pinnacle West APS	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	Pinnacle West APS	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	Pinnacle West APS	XBRL Taxonomy Definition Linkbase Document

*Furnished herewith as an Exhibit.

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

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

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

SIGNATURES

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

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Dated: November 8, 2018 By: /s/ James R. Hatfield
James R. Hatfield
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer and
Officer Duly Authorized to sign this Report)

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Dated: November 8, 2018 By: /s/ James R. Hatfield
James R. Hatfield
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer and
Officer Duly Authorized to sign this Report)