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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2026

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 registrant as specified in its charter; State or other jurisdiction of incorporation or organization; Address of principal executive offices, including zip code; and Registrant's telephone number, including area code	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

Not Applicable
(Former name, former address and former fiscal year, if changed since last report)

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

	Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Pinnacle West Capital Corporation	Common Stock, no par value	PNW	New York Stock Exchange

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit 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, a 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 the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

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

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

PINNACLE WEST CAPITAL CORPORATION	Number of shares of common stock, no par value, outstanding as of July 28, 2026:	121,197,234
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of July 28, 2026:	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 General Instruction H(2).

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This combined quarterly report on 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 unless context otherwise requires. 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 of this report also includes Combined Notes to Condensed Consolidated Financial Statements.

GLOSSARY OF NAMES AND TECHNICAL TERMS

ACC	Arizona Corporation Commission
ADEQ	Arizona Department of Environmental Quality
AFUDC	Allowance for funds used during construction
AI	Artificial intelligence
APS	Arizona Public Service Company, a subsidiary of the Company
ARO	Asset retirement obligations
ASRFP	All-source request for proposal
ASU	Accounting Standards Update
ATM Program	At-the-market equity distribution program
Base Fuel Rate	The portion of APS's retail base rates attributable to fuel and purchased power costs
BCE	Bright Canyon Energy Corporation
BESS	Battery energy storage system
Captive	Captive Insurance Cell
CCR	Coal combustion residuals
CCRMU	Coal combustion residuals management unit
CCS	Carbon capture and sequestration or utilization controls
CERCLA or Superfund	Comprehensive Environmental Response Compensation and Liability Act
Cholla	Cholla Power Plant
DG	Distributed Generation
DOE	United States Department of Energy
DSM	Demand Side Management
EES	Energy Efficiency Standard
El Dorado	El Dorado Investment Company, a subsidiary of the Company
ELG	Effluent Limitation Guidelines
EPA	United States Environmental Protection Agency
FERC	United States Federal Energy Regulatory Commission
Four Corners	Four Corners Power Plant
FRAM	Formula Rate Adjustment Mechanism
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
kV	Kilovolt, one thousand volts
kWh	Kilowatt-hour, one thousand watts per hour
LFCR	Lost Fixed Cost Recovery Mechanism
MW	Megawatt, one million watts
MWh	Megawatt-hour, one million watts per hour
NAAQS	National Ambient Air Quality Standards
Navajo Plant	Navajo Generating Station
NPDES	National Pollutant Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NTEC	Navajo Transitional Energy Company, LLC
NEIL	Nuclear Electric Insurance Limited
Ocotillo	Ocotillo Power Plant
Palo Verde	Palo Verde Generating Station or PVGS
PFAS	Per- and polyfluoroalkyl compounds
Pinnacle West	Pinnacle West Capital Corporation (any use of the words "Company," "we," "us," and "our" refer to Pinnacle West unless the context requires otherwise)
PNW Power	Pinnacle West Power, LLC, a subsidiary of the Company
PPA	Power purchase agreement
PSA	Power Supply Adjustor
PTC	Production tax credit
Redhawk	Redhawk Power Plant
RES	Renewable Energy Standard
ROD	Record of Decision
ROO	Recommended Opinion and Order

Salt River Project or SRP	Salt River Project Agricultural Improvement and Power District
SEC	United States Securities and Exchange Commission
SOFR	Secured Overnight and Financing Rate
SRB	System Reliability Benefit Mechanism
Sundance	Sundance Power Plant
TCA	Transmission cost adjustor
TEAM	Tax expense adjustor mechanism
VIE	Variable interest entity
WEIM	Western Energy Imbalance Market

FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as "estimate," "predict," "may," "believe," "plan," "expect," "require," "intend," "assume," "project," "anticipate," "goal," "seek," "strategy," "likely," "should," "will," "could," and similar words. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from outcomes currently expected or sought by Pinnacle West or APS. In addition to the Risk Factors described in Part I, Item 1A of the Pinnacle West/APS Annual Report on Form 10-K for the fiscal year ended December 31, 2025 ("2025 Form 10-K"), and Part II, Item 1A of this report, these factors include, but are not limited to:

- our ability to achieve timely and adequate rate recovery of our costs through our regulated rates and adjustor recovery mechanisms, including returns on and of debt and equity capital investment;
- the impacts of federal, state, and local laws, judicial decisions, statutes, regulations, and FERC, NRC, EPA, ACC, and other agency requirements, including as they are changed by legislative and regulatory action as well as executive orders, such as those relating to tax, environment, energy, nuclear plants, and deregulation of the retail electric market;
- our operation of Palo Verde is subject to substantial regulatory oversight and potentially significant liabilities and capital expenditures;
- we are subject to numerous environmental laws and changes to existing laws, or new laws, may increase our costs and impact our business;
- the potential effects of climate change on our electric system, including as a result of weather extremes, such as prolonged drought and high temperature variations in the area where APS conducts its business, as well as the impacts of policy and regulatory changes introduced to address climate change;
- co-owners of our jointly owned generation and transmission facilities may have unaligned goals;
- the willingness or ability of counterparties, participants, and landowners to meet contractual or other obligations or extend the rights for continued generation and transmission operations;
- deregulation of the electric industry and other factors, such as large customers developing large, utility scale generation to serve their energy needs, may result in increased competition;
- variations in demand for electricity, including those due to weather, seasonality (including large increases in ambient temperatures), the general economy or social conditions, customer and sales growth (or decline), data center growth (or lack thereof), including to support the AI industry, the effects of energy conservation measures and DG, and technological advancements;
- wildfires, including those arising as a result of climate change, extreme weather events, or the expansion of the wildland urban interface;
- generation, transmission, and distribution facilities and system operating costs, conditions, performance, and outages;
- our ability and efforts to meet current and anticipated future needs for generation and transmission and distribution facilities in our region at reliable levels, including factors affecting our ability to acquire and develop new resources to serve this load as well as difficulties in accurately forecasting load growth, particularly from high load energy users;
- availability of fuel and water supplies as well as the volatility and costs of fuel and purchased power;
- the direct or indirect effect on our facilities or business from cybersecurity threats or intrusions, data security breaches, terrorist attack, physical attack, severe storms, or other catastrophic events, such as fires, explosions, pandemic health events, or similar occurrences;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- the development of new technologies and the impact they have on the retail and wholesale electricity market and the impacts of our adoption or failure to adopt such technologies;
- the availability and retention of qualified personnel and the need to negotiate collective bargaining agreements with union employees;

- the cost of debt, including increased cost as a result of rising interest rates, and equity capital and our ability to access capital markets when required as well as the impacts a credit rating downgrade would have on us;
- the investment performance of the assets of our nuclear decommissioning trust, captive insurance cell, coal mine reclamation escrow, pension, and other postretirement benefit plans, and the resulting impact on future funding requirements;
- Pinnacle West's cash flow depends on the performance of APS and its ability to make dividends and distributions;
- potential shortfalls in insurance coverage;
- Pinnacle West's ability to meet its debt service obligation could be adversely affected because its debt securities are structurally subordinated to the debt securities and obligations of its subsidiaries;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;
- policy changes in Arizona or other states through ballot initiatives or referenda may increase our cost or operations or affect our business plans;
- general economic conditions, such as tariffs, inflation, and other supply chain constraints, as well as uncertainties associated with the current and future economic environment and conditions in Arizona; and
- disruptions in financial markets could adversely affect our cost of and access to credit and capital markets.

These and other factors are discussed in the Risk Factors described in Part I, Item 1A of our 2025 Form 10-K, Part II, Item 1A of this report, and in Part I, Item 2 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" of this report, which readers should review carefully before placing any reliance on our financial statements or disclosures. Neither Pinnacle West nor APS assumes any obligation to update these statements, even if our internal estimates change, except as required by law.

PART I — FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

INDEX TO FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
OPERATING REVENUES (Note 4)	$ 1,455,749	$ 1,358,751	$ 2,605,346	$ 2,391,031
OPERATING EXPENSES				
Fuel and purchased power	558,498	477,008	995,227	857,079
Operations and maintenance	283,387	286,605	560,087	586,714
Depreciation and amortization	243,226	228,893	483,084	463,833
Taxes other than income taxes	61,684	57,651	123,656	117,005
Other expense	3,282	1,042	6,446	1,626
Total	1,150,077	1,051,199	2,168,500	2,026,257
OPERATING INCOME	305,672	307,552	436,846	364,774
OTHER INCOME (DEDUCTIONS)				
Allowance for equity funds used during construction	17,052	14,767	31,834	28,016
Pension and other postretirement non-service credits, net (Note 8)	5,018	3,692	9,000	6,650
Other income (Note 12)	13,096	12,104	18,077	29,565
Other expense (Note 12)	(6,570)	(4,259)	(9,310)	(6,829)
Total	28,596	26,304	49,601	57,402
INTEREST EXPENSE				
Interest charges	133,601	113,527	259,360	218,470
Allowance for borrowed funds used during construction	(11,402)	(11,559)	(21,265)	(21,661)
Total	122,199	101,968	238,095	196,809
Income Before Income Taxes	212,069	231,888	248,352	225,367
Income taxes	31,302	35,018	32,471	28,835
Net Income	180,767	196,870	215,881	196,532
Less: Net income attributable to noncontrolling interests (Note 9)	2,193	4,306	4,387	8,612
Net Income Attributable to Common Shareholders	$ 178,574	$ 192,564	$ 211,494	$ 187,920
Weighted-average common shares outstanding - basic	121,306	119,517	121,333	119,555
Weighted-average common shares outstanding - diluted	124,494	121,865	124,136	121,813
Earnings Per Weighted-Average Common Share Outstanding				
Net income attributable to common shareholders - basic	$ 1.47	$ 1.61	$ 1.74	$ 1.57
Net income attributable to common shareholders - diluted	$ 1.43	$ 1.58	$ 1.70	$ 1.54

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
NET INCOME	$ 180,767	$ 196,870	$ 215,881	$ 196,532
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX				
Derivative instruments net unrealized gain (loss), net of tax benefit (expense) of $(6), $(18), $8 and $(18)	18	(294)	(25)	56
Pension and other postretirement benefit activity, net of tax benefit (expense) of $(295), $69, $(460) and $(95)	897	(53)	1,399	445
Total other comprehensive income (loss)	915	(347)	1,374	501
COMPREHENSIVE INCOME	181,682	196,523	217,255	197,033
Less: Comprehensive income attributable to noncontrolling interests	2,193	4,306	4,387	8,612
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 179,489	$ 192,217	$ 212,868	$ 188,421

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

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

	June 30, 2026	December 31, 2025
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 9,124	$ 6,604
Customer and other receivables	775,549	579,831
Accrued unbilled revenues (Note 4)	283,012	173,692
Allowance for doubtful accounts (Note 4)	(22,405)	(25,495)
Materials and supplies (at average cost)	603,676	546,329
Income tax receivable	3,494	5,979
Fossil fuel (at average cost)	21,564	18,824
Assets from risk management activities (Note 10)	5	3,250
Deferred fuel and purchased power regulatory asset (Note 7)	—	149,068
Other regulatory assets (Note 7)	150,106	136,941
Other current assets	178,791	108,686
Total current assets	2,002,916	1,703,709
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 14 and 15)	1,467,958	1,414,166
Other special use funds (Notes 14 and 15)	431,869	434,827
Assets from risk management activities (Note 10)	—	5,137
Other assets	168,703	144,997
Total investments and other assets	2,068,530	1,999,127
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	27,914,887	27,370,296
Accumulated depreciation and amortization	(9,303,903)	(9,012,021)
Net	18,610,984	18,358,275
Construction work in progress	2,196,736	1,649,542
Palo Verde sale leaseback, net of accumulated depreciation (Note 9)	31,248	32,035
Intangible assets, net of accumulated amortization	535,799	575,978
Nuclear fuel, net of accumulated amortization	133,649	104,274
Total property, plant and equipment	21,508,416	20,720,104
DEFERRED DEBITS		
Regulatory assets (Note 7)	1,451,328	1,463,357
Operating lease right-of-use assets (Note 17)	5,010,817	3,649,669
Assets for other postretirement benefits (Note 8)	399,461	399,334
Other	135,406	96,299
Total deferred debits	6,997,012	5,608,659
TOTAL ASSETS	$ 32,576,874	$ 30,031,599

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

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

	June 30, 2026	December 31, 2025
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 641,564	$ 680,203
Accrued taxes	188,912	186,605
Accrued interest	115,015	105,637
Common dividends payable	110,284	110,022
Short-term borrowings (Note 6)	818,600	757,005
Current maturities of long-term debt (Note 6)	775,000	600,000
Customer deposits	79,063	63,776
Liabilities from risk management activities (Note 10)	70,984	35,141
Deferred fuel and purchased power regulatory liability (Note 7)	61,437	—
Liabilities for asset retirements	57,776	71,698
Operating lease liabilities (Note 17)	193,207	188,586
Regulatory liabilities (Note 7)	133,206	210,909
Other current liabilities	126,477	151,444
Total current liabilities	3,371,525	3,161,026
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 6)	9,775,808	9,205,676
DEFERRED CREDITS AND OTHER		
Liabilities from risk management activities (Note 10)	10,143	1,495
Deferred income taxes	2,520,548	2,470,932
Regulatory liabilities (Note 7)	1,783,225	1,736,121
Liabilities for pension benefits (Note 8)	181,187	167,636
Liabilities for asset retirements	1,242,259	1,198,601
Customer advances	852,524	632,169
Coal mine reclamation	163,784	159,587
Deferred investment tax credit	303,008	308,261
Unrecognized tax benefits	108,673	105,484
Operating lease liabilities (Note 17)	4,942,680	3,548,365
Other	246,423	249,171
Total deferred credits and other	12,354,454	10,577,822
COMMITMENTS AND CONTINGENCIES (Note 11)		
EQUITY		
Common stock, no par value; 300,000,000 shares authorized, 121,238,487 and 120,950,839 shares issued at respective dates	3,227,362	3,231,372
Treasury stock at cost; 46,968 and 46,968 shares at respective dates	(3,323)	(3,323)
Total common stock	3,224,039	3,228,049
Retained earnings	3,841,749	3,850,817
Accumulated other comprehensive loss (Note 16)	(31,034)	(32,408)
Total shareholders' equity	7,034,754	7,046,458
Noncontrolling interests (Note 9)	40,333	40,617
Total equity	7,075,087	7,087,075
TOTAL LIABILITIES AND EQUITY	$ 32,576,874	$ 30,031,599

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

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

	Six Months Ended June 30, 2026	Six Months Ended June 30, 2025
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 215,881	$ 196,532
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	517,249	492,225
Allowance for equity funds used during construction	(31,834)	(28,016)
Deferred income taxes	23,893	1,439
Deferred investment tax credit	(5,253)	(3,301)
Stock compensation	12,858	12,356
Changes in current assets and liabilities:		
Customer and other receivables	(199,090)	(47,587)
Accrued unbilled revenues	(109,320)	(95,424)
Materials, supplies and fossil fuel	(60,087)	(25,497)
Income tax receivable	2,485	—
Deferred fuel and purchased power	(69,325)	(95,850)
Deferred fuel and purchased power amortization	279,830	201,035
Other current assets	(43,243)	(41,851)
Accounts payable	(49,408)	127,970
Accrued taxes	2,307	29,597
Other current liabilities	21,552	1,182
Change in long-term regulatory assets	19,074	38,992
Change in long-term regulatory liabilities	8,863	44,860
Change in other long-term assets	(126,896)	(140,504)
Change in operating lease assets	32,746	138,439
Change in other long-term liabilities	211,877	(56,639)
Change in operating lease liabilities	(24,887)	(86,632)
Net cash provided by operating activities	629,272	663,326
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(1,357,028)	(1,332,068)
Contributions in aid of construction	177,299	107,716
Allowance for borrowed funds used during construction	(21,265)	(21,661)
Proceeds from nuclear decommissioning trusts sales and other special use funds	997,627	919,644
Investment in nuclear decommissioning trusts and other special use funds	(990,269)	(920,785)
Other	(6,662)	(6,178)
Net cash used for investing activities	(1,200,298)	(1,253,332)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	1,092,665	795,404
Repayment of long-term debt	(350,000)	(800,000)
Short-term borrowings and (repayments), net	61,595	436,549
Short-term debt borrowings under term loan facility	—	400,000
Dividends paid on common stock	(218,740)	(210,150)
Common stock equity issuance and (purchases), net	(7,302)	(6,166)
Capital activities by noncontrolling interests	(4,672)	(10,628)
Net cash provided by financing activities	573,546	605,009
NET INCREASE IN CASH AND CASH EQUIVALENTS	2,520	15,003
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	6,604	3,838
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 9,124	$ 18,841

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

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

	Three Months Ended June 30, 2026							
	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, March 31, 2026	121,233,629	$ 3,219,691	(46,968)	$ (3,323)	$ 3,883,738	$ (31,949)	$ 42,811	$ 7,110,968
Net income		—		—	178,574	—	2,193	180,767
Other comprehensive income		—		—	—	915	—	915
Dividends on common stock ($1.82 per share)		—		—	(220,565)	—	—	(220,565)
Issuance of common stock (a)	4,858	7,671		—	—	—	—	7,671
Capital activities by noncontrolling interests		—		—	—	—	(4,672)	(4,672)
Other		—		—	2	—	1	3
Balance, June 30, 2026	121,238,487	$ 3,227,362	(46,968)	$ (3,323)	$ 3,841,749	$ (31,034)	$ 40,333	$ 7,075,087

(a) See Note 13 for information related to our equity forward sale agreements.

	Three Months Ended June 30, 2025							
	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, March 31, 2025	119,445,299	$ 3,109,612	(46,968)	$ (3,323)	$ 3,662,313	$ (30,094)	$ 107,474	$ 6,845,982
Net income		—		—	192,564	—	4,306	196,870
Other comprehensive loss		—		—	—	(347)	—	(347)
Dividends on common stock ($1.79 per share)		—			(213,731)	—	—	(213,731)
Issuance of common stock (a)	27,640	9,792		—	—	—	—	9,792
Capital activities by noncontrolling interests		—		—	—	—	(10,628)	(10,628)
Other		—		—	2	—	—	2
Balance, June 30, 2025	119,472,939	$ 3,119,404	(46,968)	$ (3,323)	$ 3,641,148	$ (30,441)	$ 101,152	$ 6,827,940

(a) See Note 13 for information related to our equity forward sale agreements.

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

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

	Six Months Ended June 30, 2026							
	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, December 31, 2025	120,950,839	$ 3,231,372	(46,968)	$ (3,323)	$ 3,850,817	$ (32,408)	$ 40,617	$ 7,087,075
Net income		—		—	211,494	—	4,387	215,881
Other comprehensive income		—		—	—	1,374	—	1,374
Dividends on common stock ($1.82 per share)		—		—	(220,565)	—	—	(220,565)
Issuance of common stock (a)	287,648	(4,010)		—	—	—	—	(4,010)
Capital activities by noncontrolling interests		—		—	—	—	(4,672)	(4,672)
Other		—		—	3	—	1	4
Balance, June 30, 2026	121,238,487	$ 3,227,362	(46,968)	$ (3,323)	$ 3,841,749	$ (31,034)	$ 40,333	$ 7,075,087

(a) See Note 13 for information related to our equity forward sale agreements.

	Six Months Ended June 30, 2025							
	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, December 31, 2024	119,143,782	$ 3,121,617	(46,968)	$ (3,323)	$ 3,666,959	$ (30,942)	$ 103,167	$ 6,857,478
Net income		—		—	187,920	—	8,612	196,532
Other comprehensive income		—		—	—	501	—	501
Dividends on common stock ($1.79 per share)		—		—	(213,731)	—	—	(213,731)
Issuance of common stock (a)	329,157	(2,213)		—	—	—	—	(2,213)
Capital activities by noncontrolling interests		—		—	—	—	(10,628)	(10,628)
Other		—		—	—	—	1	1
Balance, June 30, 2025	119,472,939	$ 3,119,404	(46,968)	$ (3,323)	$ 3,641,148	$ (30,441)	$ 101,152	$ 6,827,940

(a) See Note 13 for information related to our equity forward sale agreements.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
OPERATING REVENUES (Note 4)	$ 1,455,749	$ 1,358,751	$ 2,605,346	$ 2,391,031
OPERATING EXPENSES				
Fuel and purchased power	558,498	477,008	995,227	857,079
Operations and maintenance	281,122	285,211	554,437	581,862
Depreciation and amortization	243,208	228,876	483,050	463,799
Taxes other than income taxes	61,677	57,642	123,640	116,978
Other expense	3,282	1,042	6,446	1,626
Total	1,147,787	1,049,779	2,162,800	2,021,344
OPERATING INCOME	307,962	308,972	442,546	369,687
OTHER INCOME (DEDUCTIONS)				
Allowance for equity funds used during construction	17,052	14,767	31,834	28,016
Pension and other postretirement non-service credits, net (Note 8)	5,228	3,916	9,433	7,116
Other income (Note 12)	1,775	3,674	4,420	9,396
Other expense (Note 12)	(5,766)	(3,890)	(8,434)	(6,223)
Total	18,289	18,467	37,253	38,305
INTEREST EXPENSE				
Interest charges	108,024	91,915	209,818	180,686
Allowance for borrowed funds used during construction	(11,402)	(11,559)	(21,265)	(21,661)
Total	96,622	80,356	188,553	159,025
Income Before Income Taxes	229,629	247,083	291,246	248,967
Income taxes	36,210	38,679	43,882	35,978
Net Income	193,419	208,404	247,364	212,989
Less: Net income attributable to noncontrolling interests (Note 9)	2,193	4,306	4,387	8,612
Net Income Attributable to Common Shareholder	$ 191,226	$ 204,098	$ 242,977	$ 204,377

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	**2025**	**2026**	**2025**
NET INCOME	$ 193,419	$ 208,404	$ 247,364	$ 212,989
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX				
Pension and other postretirement benefits activity, net of tax benefit (expense) of $(282), $44, $(417) and $(89)	860	(136)	1,270	270
Total other comprehensive income (loss)	860	(136)	1,270	270
COMPREHENSIVE INCOME	194,279	208,268	248,634	213,259
Less: Comprehensive income attributable to noncontrolling interests	2,193	4,306	4,387	8,612
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 192,086	$ 203,962	$ 244,247	$ 204,647

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

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

	June 30, 2026	December 31, 2025
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 6,764	$ 4,143
Customer and other receivables	774,217	592,146
Accrued unbilled revenues (Note 4)	283,012	173,692
Allowance for doubtful accounts (Note 4)	(22,405)	(25,495)
Materials and supplies (at average cost)	603,676	546,329
Fossil fuel (at average cost)	21,564	18,824
Assets from risk management activities (Note 10)	5	3,250
Deferred fuel and purchased power regulatory asset (Note 7)	—	149,068
Other regulatory assets (Note 7)	150,106	136,941
Other current assets	178,046	102,820
Total current assets	1,994,985	1,701,718
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 14 and 15)	1,467,958	1,414,166
Other special use funds (Notes 14 and 15)	385,736	394,514
Assets from risk management activities (Note 10)	—	5,137
Other assets	55,477	50,912
Total investments and other assets	1,909,171	1,864,729
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	27,914,005	27,369,414
Accumulated depreciation and amortization	(9,303,021)	(9,011,139)
Net	18,610,984	18,358,275
Construction work in progress	2,196,736	1,649,542
Palo Verde sale leaseback, net of accumulated depreciation (Note 9)	31,248	32,035
Intangible assets, net of accumulated amortization	535,644	575,823
Nuclear fuel, net of accumulated amortization	133,649	104,274
Total property, plant and equipment	21,508,261	20,719,949
DEFERRED DEBITS		
Regulatory assets (Note 7)	1,451,328	1,463,357
Operating lease right-of-use assets (Note 17)	5,009,873	3,648,658
Assets for other postretirement benefits (Note 8)	392,477	392,348
Other	134,598	95,600
Total deferred debits	6,988,276	5,599,963
TOTAL ASSETS	$ 32,400,693	$ 29,886,359

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

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

	June 30, 2026	December 31, 2025
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 635,832	$ 672,518
Accrued taxes	196,786	176,968
Accrued interest	107,233	98,434
Common dividends payable	110,600	110,000
Short-term borrowings (Note 6)	540,000	507,305
Current maturities of long-term debt (Note 6)	250,000	250,000
Customer deposits	79,063	63,776
Liabilities from risk management activities (Note 10)	70,984	35,141
Deferred fuel and purchased power regulatory liability (Note 7)	61,437	—
Liabilities for asset retirements	57,776	71,698
Operating lease liabilities (Note 17)	193,051	188,437
Regulatory liabilities (Note 7)	133,206	210,909
Other current liabilities	125,739	159,039
Total current liabilities	2,561,707	2,544,225
DEFERRED CREDITS AND OTHER		
Liabilities from risk management activities (Note 10)	10,143	1,495
Deferred income taxes	2,476,683	2,427,765
Regulatory liabilities (Note 7)	1,783,225	1,736,121
Liabilities for pension benefits (Note 8)	179,563	164,892
Liabilities for asset retirements	1,242,259	1,198,601
Customer advances	852,524	632,169
Coal mine reclamation	163,784	159,587
Deferred investment tax credit	303,008	308,261
Unrecognized tax benefits	124,255	121,066
Operating lease liabilities (Note 17)	4,941,715	3,547,321
Other	231,164	232,661
Total deferred credits and other	12,308,323	10,529,939
COMMITMENTS AND CONTINGENCIES (Note 11)		
CAPITALIZATION		
Common stock	178,162	178,162
Additional paid-in capital	4,591,696	4,491,696
Retained earnings	4,249,317	4,227,237
Accumulated other comprehensive loss (Note 16)	(14,187)	(15,457)
Total shareholder equity	9,004,988	8,881,638
Noncontrolling interests (Note 9)	40,333	40,617
Total equity	9,045,321	8,922,255
Long-term debt less current maturities (Note 6)	8,485,342	7,889,940
Total capitalization	17,530,663	16,812,195
TOTAL LIABILITIES AND EQUITY	$ 32,400,693	$ 29,886,359

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

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

	Six Months Ended June 30, 2026	Six Months Ended June 30, 2025
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 247,364	$ 212,989
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	517,215	492,191
Allowance for equity funds used during construction	(31,834)	(28,016)
Deferred income taxes	23,230	(8,702)
Deferred investment tax credit	(5,253)	(3,301)
Changes in current assets and liabilities:		
Customer and other receivables	(185,443)	(47,549)
Accrued unbilled revenues	(109,320)	(95,424)
Materials, supplies and fossil fuel	(60,087)	(25,497)
Deferred fuel and purchased power	(69,325)	(95,850)
Deferred fuel and purchased power amortization	279,830	201,035
Income tax receivable	—	5,421
Other current assets	(48,364)	(41,854)
Accounts payable	(47,455)	125,387
Accrued taxes	19,818	44,905
Other current liabilities	12,633	(12,544)
Change in long-term regulatory assets	19,074	38,992
Change in long-term regulatory liabilities	8,863	44,860
Change in other long-term assets	(113,551)	(117,624)
Change in operating lease assets	32,679	138,376
Change in other long-term liabilities	223,225	(43,634)
Change in operating lease liabilities	(24,808)	(86,558)
Net cash provided by operating activities	688,491	697,603
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(1,357,028)	(1,332,068)
Contributions in aid of construction	177,299	107,716
Allowance for borrowed funds used during construction	(21,265)	(21,661)
Proceeds from nuclear decommissioning trusts sales and other special use funds	991,873	869,190
Investment in nuclear decommissioning trusts and other special use funds	(980,469)	(870,331)
Other	1,157	(756)
Net cash used for investing activities	(1,188,433)	(1,247,910)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	594,840	—
Repayment of long-term debt	—	(300,000)
Short-term borrowings and (repayments), net	32,695	385,500
Short-term debt borrowings under term loan facility	—	400,000
Equity infusion from Pinnacle West	100,000	300,000
Dividends paid on common stock	(220,300)	(213,900)
Capital activities by noncontrolling interests	(4,672)	(10,628)
Net cash provided by financing activities	502,563	560,972
NET INCREASE IN CASH AND CASH EQUIVALENTS	2,621	10,665
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	4,143	3,815
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 6,764	$ 14,480

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

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

	Three Months Ended June 30, 2026						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, March 31, 2026	71,264,947	$ 178,162	$ 4,491,696	$ 4,278,990	$ (15,047)	$ 42,811	$ 8,976,612
Equity infusion from Pinnacle West		—	100,000	—	—	—	100,000
Net income		—	—	191,226	—	2,193	193,419
Other comprehensive income		—	—	—	860	—	860
Dividends on common stock		—	—	(220,900)	—	—	(220,900)
Capital activities by noncontrolling interests		—	—	—	—	(4,672)	(4,672)
Other		—	—	1	—	1	2
Balance, June 30, 2026	71,264,947	$ 178,162	$ 4,591,696	$ 4,249,317	$ (14,187)	$ 40,333	$ 9,045,321

	Three Months Ended June 30, 2025						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, March 31, 2025	71,264,947	$ 178,162	$ 4,116,696	$ 3,992,700	$ (13,710)	$ 107,474	$ 8,381,322
Equity infusion from Pinnacle West		—	300,000	—	—	—	300,000
Net income		—	—	204,098	—	4,306	208,404
Other comprehensive loss		—	—	—	(136)	—	(136)
Dividends on common stock		—	—	(213,600)	—	—	(213,600)
Capital activities by noncontrolling interests		—	—	—	—	(10,628)	(10,628)
Other		—	—	4	—	—	4
Balance, June 30, 2025	71,264,947	$ 178,162	$ 4,416,696	$ 3,983,202	$ (13,846)	$ 101,152	$ 8,665,366

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

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

	Six Months Ended June 30, 2026						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, December 31, 2025	71,264,947	$ 178,162	$ 4,491,696	$ 4,227,237	$ (15,457)	$ 40,617	$ 8,922,255
Equity infusion from Pinnacle West		—	100,000	—	—	—	100,000
Net income		—	—	242,977	—	4,387	247,364
Other comprehensive income		—	—	—	1,270	—	1,270
Dividends on common stock		—	—	(220,900)	—	—	(220,900)
Capital activities by noncontrolling interests		—	—	—	—	(4,672)	(4,672)
Other		—	—	3	—	1	4
Balance, June 30, 2026	71,264,947	$ 178,162	$ 4,591,696	$ 4,249,317	$ (14,187)	$ 40,333	$ 9,045,321

	Six Months Ended June 30, 2025						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, December 31, 2024	71,264,947	$ 178,162	$ 4,116,696	$ 3,992,423	$ (14,116)	$ 103,167	$ 8,376,332
Equity infusion from Pinnacle West		—	300,000	—	—	—	300,000
Net income		—	—	204,377	—	8,612	212,989
Other comprehensive income		—	—	—	270	—	270
Dividends on common stock		—	—	(213,600)	—	—	(213,600)
Capital activities by noncontrolling interests		—	—	—	—	(10,628)	(10,628)
Other		—	—	2	—	1	3
Balance, June 30, 2025	71,264,947	$ 178,162	$ 4,416,696	$ 3,983,202	$ (13,846)	$ 101,152	$ 8,665,366

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, including APS, El Dorado, and PNW Power. Intercompany accounts and transactions between the consolidated companies have been eliminated. The unaudited Condensed Consolidated Financial Statements for Pinnacle West include the accounts of Pinnacle West and its subsidiaries as well as a VIE related to the Captive. The unaudited Condensed Consolidated Financial Statements for APS include the accounts of APS and the Palo Verde VIEs. In September 2025, APS purchased two of the three leased interests, resulting in the termination of the related lease agreements and discontinuation of VIE consolidation for those leases. As of June 30, 2026, one Palo Verde VIE lease arrangement remains active. See Note 9 for further discussion on Pinnacle West's VIEs and APS's remaining VIE. El Dorado is a wholly-owned subsidiary that invests in energy-related and Arizona community-based ventures. PNW Power is a wholly-owned subsidiary that holds certain investments in wind and transmission joint venture projects. Our accounting records are maintained in accordance with 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 unaudited 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, 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 2025 Form 10-K.

Supplemental Cash Flow Information

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

	Six Months Ended June 30,	
	2026	2025
Cash paid during the period for:		
Income taxes, net of refunds/credits	$ 8,112	$ 7,743
Interest, net of amounts capitalized	223,625	189,041
Significant non-cash investing and financing activities:		
Accrued capital expenditures	291,902	312,762
Dividends accrued but not yet paid	110,284	106,869

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

	Six Months Ended June 30,	
	2026	2025
Cash paid during the period for:		
Income taxes, net of refunds/credits	$ 10,260	$ 10,369
Interest, net of amounts capitalized	177,122	158,073
Significant non-cash investing and financing activities:		
Accrued capital expenditures	291,902	312,762
Dividends accrued but not yet paid	110,600	106,900

2. Business Segments

Pinnacle West's reportable business segment is our regulated electricity segment, which consists of retail and wholesale sales supplied under traditional cost-based regulation and related activities and includes electricity generation, transmission, and distribution. Our reportable segment activities are conducted through our wholly-owned subsidiary, APS. All other operating segment activities are insignificant to Pinnacle West.

For segment reporting purposes, Pinnacle West's Chief Executive Officer performs the function of chief operating decision maker ("CODM"). Our CODM uses net income to measure an operating segment's profitability. When assessing the performance of an operating segment, and making decisions about allocating resources, our CODM evaluates net income actual results compared to budget. Net income is also used when implementing strategic initiatives and selecting projects to meet business objectives. Our reportable segment's revenue streams are dependent upon regulated rate recovery, which is a primary factor in how we identify operating segments.

For information on our reportable business segment's revenues, significant expenses, net income (loss), assets, and other reportable segment items, see the APS Condensed Consolidated Statements of Income, APS Condensed Consolidated Balance Sheets, and APS Condensed Consolidated Statements of Cash Flows.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table reconciles our reportable segment's revenues, significant expenses, and net income (loss) to the Pinnacle West consolidated amounts (dollars in millions):

	Three Months Ended June 30,					
	2026			2025		
	Regulated Electricity Segment	Other	Pinnacle West Consolidated	Regulated Electricity Segment	Other	Pinnacle West Consolidated
Operating revenues	$ 1,456	$ —	$ 1,456	$ 1,359	$ —	$ 1,359
Fuel and purchased power	(558)	—	(558)	(477)	—	(477)
Operations and maintenance	(281)	(2)	(283)	(285)	(2)	(287)
Depreciation and amortization	(243)	—	(243)	(229)	—	(229)
Taxes other than income taxes	(62)	—	(62)	(58)	—	(58)
Allowance for equity funds used during construction	17	—	17	15	—	15
Pension and other postretirement non-service credits, net	5	—	5	4	—	4
Other income and (expense), net	(8)	10	2	(2)	9	7
Interest charges, net of allowance for borrowed funds used during construction	(97)	(25)	(122)	(80)	(22)	(102)
Income (taxes) benefit	(36)	5	(31)	(39)	4	(35)
Less: Net income attributable to noncontrolling interests	(2)	—	(2)	(4)	—	(4)
Net Income (Loss) Attributable to Common Shareholders	$ 191	$ (12)	$ 179	$ 204	$ (11)	$ 193

	Six Months Ended June 30,					
	2026			2025		
	Regulated Electricity Segment	Other	Pinnacle West Consolidated	Regulated Electricity Segment	Other	Pinnacle West Consolidated
Operating revenues	$ 2,605	$ —	$ 2,605	$ 2,391	$ —	$ 2,391
Fuel and purchased power	(995)	—	(995)	(857)	—	(857)
Operations and maintenance	(554)	(6)	(560)	(582)	(5)	(587)
Depreciation and amortization	(483)	—	(483)	(464)	—	(464)
Taxes other than income taxes	(124)	—	(124)	(117)	—	(117)
Allowance for equity funds used during construction	32	—	32	28	—	28
Pension and other postretirement non-service credits, net	9	—	9	7	—	7
Other income and (expense), net	(10)	11	1	2	20	22
Interest charges, net of allowance for borrowed funds used during construction	(189)	(49)	(238)	(159)	(38)	(197)
Income taxes	(44)	12	(32)	(36)	7	(29)
Less: Net income attributable to noncontrolling interests	(4)	—	(4)	(9)	—	(9)
Net Income (Loss) Attributable to Common Shareholders	$ 243	$ (32)	$ 211	$ 204	$ (16)	$ 188

The following table reconciles our reportable segment's assets to the Pinnacle West consolidated amount (dollars in millions):

	June 30, 2026			December 31, 2025		
	Regulated Electricity Segment	Other	Pinnacle West Consolidated	Regulated Electricity Segment	Other	Pinnacle West Consolidated
Total Assets	$ 32,401	$ 176	$ 32,577	$ 29,886	$ 146	$ 30,032

3. New Accounting Standards

ASU 2024-03, Income Statement Reporting: Expense Disaggregation Disclosures

In November 2024, a new accounting standard was issued that requires specific disclosures related to certain costs and expenses. Companies will be required to disclose the amounts of certain cost and expense categories, such as purchases of inventory, employee compensation, depreciation, and amortization, among other disclosures. The new disclosures may be provided in the notes to the financial statements and will not require changes to the face of the Consolidated Statements of Income. The standard becomes effective on December 31, 2027, using either a prospective or retrospective approach, with early adoption permitted. The adoption of the new standard will result in disclosure changes, but will not impact our accounting for such costs and expenses or our financial statement results. We are currently evaluating the transition method and date of adoption we will elect for this new standard.

ASU 2025-06, Intangibles—Goodwill and Other—Internal-Use Software: Targeted Improvements to the Accounting for Internal-Use Software

In September 2025, a new accounting standard was issued that modernizes the accounting for internal-use software costs by removing references to prescriptive and sequential development stages of a project and replacing them with new criteria used in determining when to start capitalizing software costs. Under the new guidance, capitalization begins when management authorizes and commits to funding the software project and it is probable the project will be completed and used as intended. When determining if a project is probable of being completed, entities must evaluate whether significant development uncertainty exists, such as unresolved technological innovations or unproven features. The new guidance also clarifies that capitalized internal-use software costs are subject to the existing property, plant, and equipment disclosure requirements.

The standard will become effective for us on January 1, 2028, with early adoption permitted. Entities may adopt the standard using one of the following transition methods: a prospective approach, a retrospective approach, or a modified transition approach that considers in-process projects at the date of adoption. We are currently evaluating the impacts on our financial statements of adopting this new standard and the transition method and date of adoption we will elect. The adoption of this guidance may impact our timing and scope of software costs eligible for capitalization, and may also impact our disclosures relating to software.

ASU 2025-09, Derivatives and Hedging: Hedge Accounting Improvements

In November 2025, a new accounting standard was issued which clarifies certain aspects of the hedge accounting guidance. The new standard is intended to better align hedge accounting with the economics of an entity’s risk management activities, and provides entities the ability to apply hedge accounting to an expanded population of economic hedges of forecasted transactions. The standard will become effective for us on January 1, 2027, applied on a prospective basis. Early adoption is permitted. We expect to adopt this guidance on January 1, 2027. We are not currently applying hedge accounting, and do not expect the adoption of this guidance will have a material impact on our financial statements.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

ASU 2025-10, Government Grants: Accounting for Government Grants Received by Business Entities

In December 2025, a new accounting standard was issued establishing authoritative GAAP guidance on the accounting for government grants received by business entities. Prior to the issuance of this new standard, GAAP did not include guidance relating to government grants received by business entities. The new standard is intended to eliminate diversity in practice and improve the financial reporting and consistency across business entities for government grants. The new standard defines government grants and includes recognition, measurement, presentation, and disclosure requirements. The new standard includes guidance pertaining to both government grants received relating to an asset and government grants received relating to income. The guidance includes recognition thresholds based on the probability of compliance with grant conditions and receipt of the grant, among other accounting requirements. Disclosure requirements include the nature and amounts of government grants received, the conditions attached to the grants, and accounting policies applied.

The new standard will become effective for us on January 1, 2029, with early adoption permitted. Entities may adopt the standard using various transition methods, including a modified prospective approach, a modified retrospective approach, or a retrospective approach to all government grants. We are currently evaluating the impacts on our financial statements of adopting this new standard, as well as the date we will adopt this guidance and the transition method we will elect.

ASU 2026-02, Environmental Credits and Environmental Credit Obligations

In May 2026, a new accounting standard was issued establishing comprehensive accounting requirements for environmental credits and environmental credit obligations. Prior to the issuance of this new standard, GAAP did not include specific guidance relating to these type of instruments and activities. The new standard defines environmental credits and environmental credit obligations and provides a framework for recognition, measurement, presentation, and disclosure.

Entities will be required to capitalize or expense an environmental credit based on the entity's planned use. Environmental credits probable of being used for regulatory compliance purposes, sold, or used in nonreciprocal transfers will qualify to be recognized as assets. Generally, environmental credit assets will initially be measured at cost, with certain exceptions. Environmental credits held solely for voluntary initiatives are required to be expensed as costs are incurred. For environmental credit obligations, entities will be required to recognize liabilities that arise from existing or enacted laws, statutes, or ordinances to prevent, control, reduce, or remove emissions or other pollution that may be settled with environmental credits. Liabilities will be measured assuming the reporting date is the end of the compliance period. The liabilities will initially be measured at a cost associated with the credit used to settle the obligation, and may be funded or unfunded obligations. The standard requires gross presentation of credits and obligations and expanded disclosures regarding credit types, intended use, estimates, and financial statement impacts.

The new standard will become effective for us on January 1, 2028, with early adoption permitted. Entities must adopt the standard using a retrospective approach through a cumulative-effect adjustment to the opening balance of retained earnings as of the beginning of the annual reporting period of adoption, without recasting any financial statement information before the period of adoption. We are currently evaluating the impacts on our financial statements of adopting this new standard, as well as the date we will adopt this guidance. As required, we will adopt the standard using the retrospective transition approach.

4. Revenue

Sources of Revenue

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
Retail Electric Service				
Residential	$ 695,702	$ 651,666	$ 1,189,403	$ 1,100,589
Non-Residential	708,268	654,038	1,310,001	1,178,895
Wholesale Energy Sales	13,709	17,893	28,685	42,717
Transmission Services for Others	29,188	31,996	61,215	57,543
Other Sources	8,882	3,158	16,042	11,287
Total Operating Revenues	$ 1,455,749	$ 1,358,751	$ 2,605,346	$ 2,391,031

Retail Electric Service

All of Pinnacle West's retail electric revenues are generated by APS. Retail electric revenue is generated by the sale of electricity to our customers within the regulated authorized service territory at tariff rates approved by the ACC and based on customer usage. Revenues related to the sale of electricity are generally recognized when service is rendered, or electricity is delivered to customers. The billing of electricity sales to individual customers is based on the reading of their meters. We obtain customers' meter data on a systematic basis throughout the month, and generally bill customers within a month from when service was provided. Customers are generally required to pay for services within 21 days of when the services are billed. See "Allowance for Doubtful Accounts" discussion below for additional details regarding payment terms. In addition, see the section titled "2025 Rate Case" in Note 7 for details related to proposed adjustments to rate design and modifications of cost allocation methodologies to reduce cross-subsidization by ensuring customers causing increased production costs are covering those costs through rates.

Wholesale Energy Sales and Transmission Services for Others

All of Pinnacle West's revenues from wholesale energy sales and transmission services for others are generated by APS and represent energy and transmission sales to wholesale customers. These activities consist of managing fuel and purchased power risks and transmission needs in connection with the cost of serving our retail customers' energy requirements. We may also sell into the wholesale markets generation that is not needed for APS's retail load. Our wholesale activities and tariff rates are regulated by FERC.

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

Revenue Activities

Our revenues primarily consist of activities that are classified as revenues from contracts with customers. We derive our revenues from contracts with customers primarily from sales of electricity to our regulated retail customers. Revenues from contracts with customers also include wholesale and transmission activities. Our revenues from contracts with customers for the three and six months ended June 30, 2026 were $1,451 million and $2,575 million, respectively, and for the three and six months ended June 30, 2025 were $1,345 million and $2,364 million, respectively.

We have certain revenues that do not meet the specific accounting criteria to be classified as revenues from contracts with customers. For the three and six months ended June 30, 2026 our revenues that do not qualify as revenue from contracts with customers were $5 million and $30 million, respectively, and for the three and six months ended June 30, 2025 were $14 million and $27 million, respectively. This amount includes revenues related to certain regulatory cost recovery mechanisms that are considered alternative revenue programs. We recognize revenue associated with alternative revenue programs when specific events permitting recognition are completed. Certain amounts associated with alternative revenue programs will subsequently be billed to customers; however, we do not reclassify billed amounts into revenue from contracts with customers. See Note 7 for a discussion of our regulatory cost recovery mechanisms.

Allowance for Doubtful Accounts

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

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

	Six Months Ended June 30, 2026	Year Ended December 31, 2025
Balance at beginning of period	$ 25,495	$ 24,849
Bad debt expense	13,528	28,603
Actual write-offs	(16,618)	(27,957)
Balance at end of period	$ 22,405	$ 25,495

5. Income Taxes

As a part of the Inflation Reduction Act of 2022 ("IRA"), a new PTC for nuclear energy produced by existing nuclear energy plants ("Nuclear PTC") was enacted, available from 2024 through 2032. The Nuclear PTC can be increased by five times if certain IRS prevailing wages rules are met. The Company continues to await guidance from the U.S. Treasury Department related to the definition of "gross receipts" from nuclear sales for purposes of the credit phase-out applicable to the Nuclear PTC.

The Company has claimed a $33.4 million benefit for the Nuclear PTC on its 2024 tax return using a revenue requirement methodology to determine its gross receipts from nuclear sales. In the continued absence of IRS guidance regarding the definition of gross receipts from nuclear sales, management intends to utilize this same methodology to claim a 2025 credit of $39.6 million. Additionally, utilizing this same methodology, the Company estimates that it may be eligible to claim a 2026 tax credit of $35-$40 million. These benefits include the five times multiplier for complying with IRS prevailing wage rules. However, due to the continued lack of IRS guidance, management believes that there remains uncertainty as to whether the IRS will ultimately agree with the Company's gross receipts methodology. As a result, as of June 30, 2026, the Company's Nuclear PTC benefits are recorded as uncertain tax positions and the Company continues to not recognize any income tax benefits related to the Nuclear PTC.

In March 2026, the IRS notified the Company of its intent to examine the Company's 2022 and 2023 federal tax returns. In May 2026, the IRS notified the Company of its intent to also include tax year 2024 into the current audit cycle. Because the examination is in its preliminary stages, we are unable at this time to predict the outcome of this matter and whether it will have a material impact on our financial position, results of operations, or cash flows.

6. 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

As of June 30, 2026, Pinnacle West had a $300 million revolving credit facility that matures on February 18, 2031. Pinnacle West has the option to increase the amount of the facility by $100 million to a total of $400 million, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on Pinnacle West's senior unsecured debt credit ratings. The facility is available to support Pinnacle West's general corporate purposes, including support for Pinnacle West's $300 million commercial paper program, bank borrowings, and issuances of letters of credit. As of June 30, 2026, Pinnacle West had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under its credit facility, and $104 million of outstanding commercial paper borrowings. The weighted-average interest rate for the outstanding borrowings on June 30, 2026 was 3.85%.

Pinnacle West has an outstanding 364-day $175 million term loan facility that matures on December 3, 2026. Borrowings under the facility bear interest at SOFR plus 0.80% per annum. On December 3, 2025, Pinnacle West drew the full amount of $175 million.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

On June 5, 2026, Pinnacle West issued $500 million of 4.65% senior unsecured notes that mature June 1, 2029. The net proceeds from the issuance were used to repay $350 million of floating rate senior unsecured notes that were due to mature June 10, 2026, to pay down $50 million of short-term indebtedness consisting of commercial paper, and for general corporate purposes.

APS

As of June 30, 2026, APS had a $1.7 billion revolving credit facility that matures on February 18, 2031. APS has the option to increase the amount of the facility by $400 million to a total of $2.1 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. The facility is available to support APS's general corporate purposes, including support for APS's $1.5 billion commercial paper program, bank borrowings, and issuances of letters of credit. As of June 30, 2026, APS had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under the credit facility, and $540 million of outstanding commercial paper borrowings. The weighted-average interest rate for the outstanding borrowings on June 30, 2026 was 3.92%.

On March 10, 2026, APS issued $600 million of 5.10% senior unsecured notes that mature March 15, 2036. The net proceeds from the issuances were used to repay short-term indebtedness consisting of commercial paper and for general corporate purposes.

On June 5, 2026, Pinnacle West contributed $100 million into APS in the form of an equity infusion. APS used this contribution to pay down short-term indebtedness consisting of commercial paper.

The ACC has authorized a limit on yearly equity infusions into APS equal to 2.5% of APS's total assets each calendar year on a three-year rolling average basis, subject to APS's equity ratio remaining below the most recently approved rate case capital structure plus 50 basis points. On July 31, 2026, APS submitted an application to the ACC requesting to increase the long-term debt limit from $9.5 billion to $12 billion. APS cannot predict the outcome of this matter.

See "Financial Assurances" in Note 11 for a discussion of other outstanding letters of credit.

Debt Fair Value

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

	As of June 30, 2026		As of December 31, 2025	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 1,815,466	$ 1,937,539	$ 1,665,736	$ 1,731,388
APS	8,735,342	7,943,535	8,139,940	7,433,142
Total	$ 10,550,808	$ 9,881,074	$ 9,805,676	$ 9,164,530

7. Regulatory Matters

ACC General Retail Rate Cases

2025 Rate Case

On June 13, 2025, APS filed an application with the ACC (the "2025 Rate Case") seeking a net base rate increase of $579.5 million, which represents a 13.99% net increase. The requested net increase addresses a total base revenue deficiency of $662.4 million, offset by proposed adjustor transfers of cost recovery to base rates.

The 2025 Rate Case application includes the following proposals:

- a test year comprised of the 12-month period ended on December 31, 2024, including certain pro forma adjustments;
- 12 months of post-test year plant placed into service from January 1, 2025 through December 31, 2025;
- an original cost rate base of $12.5 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;
- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	47.65 %	4.26 %
Common stock equity	52.35 %	10.70 %
Weighted-average cost of capital		7.63 %

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- a rate of $0.043881 per kWh for the portion of APS's base rates attributable to fuel and purchased power costs;
- adjustments to rate designs, including direct assignment of costs, to reduce cross-subsidization by certain customer classes;
- modification of cost allocation methodologies based on customer growth to ensure customers causing new production costs are covering those costs through rates, along with corresponding changes to adjustor mechanisms, such as for fuel and purchased power;
- implementation of a FRAM to assist with reducing regulatory lag and allow for rate gradualism;
- elimination of the LFCR following the first annual adjustment pursuant to the FRAM; and
- modification to the SRB due to the FRAM proposal.

On March 2 and March 18, 2026, the ACC Staff, Residential Utility Consumer Office ("RUCO"), and other intervenors filed their initial written testimony with the ACC. ACC Staff's testimony includes the following recommendations, among others, depending on the approval of APS's proposed FRAM, (i) a $525.2 million total base revenue increase, (ii) a 9.55% to 9.80% return on equity, (iii) a 0.20% return on the increment of fair value, and (iv) 12 months of post-test year plant. RUCO's testimony includes the following recommendations, among others, depending on the approval of APS's proposed FRAM, (i) a $200.2 to $278.1 million total base revenue increase, (ii) a 9.00% to 9.20% return on equity, (iii) a 0.0% return on the increment of fair value, and (iv) 0 to 12 months of post-test year plant.

On April 3, 2026 , APS filed rebuttal testimony addressing the ACC Staff and intervenors' direct testimonies. The principal provisions of APS's rebuttal testimony are as follows:

- a total revenue requirement increase of $694.2 million, or a net revenue requirement increase of $611.3 million after adjustor transfers;
- maintaining a return on equity request of 10.7%;
- reducing the return on the increment of fair value from 1.0% to 0.9%;
- maintaining a post-test year plant request of 12 months and updating the impacted projects, including Ironwood solar and Sundance; and
- an integrated set of FRAM modifications that are intended to be evaluated together:
    - allowing for an earnings test "deadband" range of +/- 40 basis points to APS's authorized return before an adjustment to the FRAM would be required;
    - limiting projected plant to six months;
    - elimination of the SRB and TEAM following the first annual adjustment pursuant to the FRAM;
    - retention of the 120-day review and challenge period; and
    - elimination of the interim rate reset by accepting Commission approval prior to implementation (subject to an automatic reversion provision).

On May 1, 2026, ACC Staff, RUCO, and other intervenors filed their surrebuttal testimonies with the ACC. The ACC Staff adjusted their initial recommendation to a $506.5 million total base revenue increase and additional revisions to APS's FRAM proposal, including the continued recommendation for an earnings test "deadband" range of +/- 50 basis points.

On May 11, 2026, APS filed its rejoinder testimony addressing the ACC Staff and intervenors' surrebuttal testimonies. APS's rejoinder testimony included adjustments to the proposed schedule for the annual FRAM filing and a reduction of the total revenue requirement increase to $691.6 million, representing a revenue requirement increase, net of adjustor transfers, of $608.7 million. All other major provisions from APS's rebuttal testimony were maintained in its rejoinder testimony.

APS requested that the increase become effective in the second half of 2026. The hearing concluded on July 7, 2026. After the conclusion of the hearing, the Administrative Law Judge overseeing the hearing issued a procedural order outlining briefing schedules and other next steps in the proceedings. The order noted that the case is anticipated to be resolved before the end of this year. APS cannot predict the outcome of its request nor when the 2025 Rate Case will be decided by the ACC.

2022 Rate Case

On October 28, 2022, APS filed an application with the ACC (the "2022 Rate Case") for an increase in retail base rates, and on January 25, 2024, an Administrative Law Judge issued a ROO, as corrected on February 6, 2024 (the "2022 Rate Case ROO").

On February 22, 2024, the ACC approved the 2022 Rate Case ROO with certain amendments that resulted in, among other things, (i) an approximately $491.7 million increase in the annual base revenue requirement, (ii) a 9.55% return on equity, (iii) a 0.25% return on the increment of fair value rate base greater than original cost, (iv) an effective fair value rate of return of 4.39%, (v) a return set at the Company's weighted average cost of capital on the net prepaid pension asset and net other post-employment benefit liability in rate base, (vi) an adjustment to generation maintenance and outage expense to reflect a more reasonable level of test year costs, (vii) approval of the SRB mechanism with modifications to customer notifications, procedural timelines and the inclusion of any qualifying technology and fuel source bid received through an ASRFP, and (viii) recovery of all DSM costs through the DSM Adjustment Charge ("DSMAC") rather than through base rates.

The ACC issued the final order for the 2022 Rate Case on March 5, 2024, with the new rates becoming effective for all service rendered on or after March 8, 2024.

Six intervenors and the Attorney General of Arizona requested rehearing on various issues included in the ACC's decision, such as the grid access charge ("GAC") for solar customers, the SRB, and Coal Community Transition funding. On April 15, 2024, the ACC granted, in part, the rehearing applications of the Attorney General, Arizona Solar Energy Industries Association ("AriSEIA"), Solar Energy Industries Association ("SEIA"), and Vote Solar specifically to review whether the GAC rate is just and reasonable, including whether it should be higher or lower, whether the GAC rate constitutes a discriminatory fee to solar customers, and whether omission of a GAC charge is discriminatory to non-solar customers. All other applications for rehearing were denied. A limited rehearing was held October 28 through November 1, 2024. Following the limited rehearing, an Administrative Law Judge issued a ROO (the "Limited Rehearing ROO") on December 3, 2024. The Limited Rehearing ROO recommended affirming the GAC as just and reasonable and that the GAC is not discriminatory to solar customers and the absence of a GAC is not discriminatory to non-solar customers. On December 17, 2024, the ACC approved the Limited Rehearing ROO with an amendment that requires APS in its next rate case to propose a revenue allocation based on a site-load cost of service study in order to bring further parity in revenue collection between solar and non-solar customers. SEIA, AriSEIA, Vote Solar, the Arizona Attorney General, and two individual customers have filed requests for rehearing of the ACC's December 17, 2024 decision on the rehearing. The ACC has taken no action on these requests. In addition, each of these parties has subsequently filed an appeal to the Arizona Court of Appeals seeking review of the ACC's decisions regarding the GAC and on rehearing. On February 25, 2026, parties provided oral arguments before the Court of Appeals. On June 16, 2026, the Arizona Court of Appeals found that the GAC and related increases for residential solar customers were imposed by the ACC without adequate notice or opportunity to be heard. APS has since moved for reconsideration of this decision and, if reconsideration is not successful, plans to seek further review of this decision before the Arizona Supreme Court. APS cannot predict the outcome of these proceedings, but does not expect the outcome will have a material impact on APS' financial position, results of operations, or cash flows.

Regulatory Lag Docket

On January 5, 2023, the ACC opened a new docket to explore the possibility of modifications to the ACC's historical test year rules. The ACC requested comments and held two workshops exploring ways to reduce regulatory lag, including alternative ratemaking structures such as future test years, hybrid test years, and formula rates. On December 3, 2024, the ACC approved a policy statement regarding formula rate plans. The policy statement provides regulated utilities with the opportunity to propose formula rate plans in future rate cases. On March 28, 2025, RUCO, the Arizona Large Customer Group ("ALCG"), and an individual customer filed a lawsuit challenging the ACC's authority to issue the formula rate policy statement outside of Arizona's formula rulemaking process. On June 13, 2025, the lawsuit challenging the ACC's formula rate policy was dismissed by the Superior Court of Maricopa County. Following the dismissal, the plaintiffs filed an appeal with the Arizona Court of Appeals as well as a Petition for Special Action with the Arizona Supreme Court. The Supreme Court declined to exercise jurisdiction on the Petition for Special Action. The plaintiffs also filed a Petition for Special Action with the Arizona Court of Appeals, which has accepted jurisdiction to determine whether the case should be remanded back to the Superior Court for expedited consideration of the merits. On November 21, 2025, the Arizona Court of Appeals ruled that the issue should be remanded back to the Superior Court to determine whether the ACC's formula rate policy must go through a formal rulemaking process. In response, APS, the ACC, and several other Arizona utility companies filed petitions for review of the Court of Appeals decision with the Arizona Supreme Court. That petition was denied on May 8, 2026, which will return the litigation to the Superior Court of Maricopa County for further proceedings on the merits of whether the ACC's issuance of the formula rate policy statement complied with the Arizona Administrative Procedure Act. APS cannot predict the outcome of this matter or the impact (if any) it may have on other proceedings.

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. See "2022 Rate Case" above for modifications of adjustment mechanisms in the 2022 Rate Case and "2025 Rate Case" above for proposed modifications to adjustment mechanisms in the 2025 Rate Case.

Renewable Energy Standard

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, for example, solar, wind, biomass, biogas, and geothermal technologies. 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.

On July 1, 2022, APS filed its 2023 RES Implementation Plan and proposed a budget of approximately $86.2 million, excluding any funding offsets. This budget contained funding for programs to comply with ACC-approved initiatives, including the 2019 Rate Case decision. APS's budget proposal supported existing approved projects and commitments and requested a waiver of the RES residential and non-residential distributed energy requirements for 2023. On November 10, 2022, the ACC approved the 2023 RES Implementation Plan, including APS's requested waiver of the distributed energy requirement for 2023.

On June 30, 2023, APS filed its 2024 RES Implementation Plan and proposed a budget of approximately $95.1 million, excluding any funding offsets. On July 1, 2024, APS filed its 2025 RES Implementation Plan and proposed a budget of approximately $92.7 million. On July 1, 2025, APS filed its 2026 RES Implementation Plan and proposed a budget of approximately $110.1 million, excluding any funding offsets. APS's budget proposal supports existing approved projects and commitments and requests a waiver of the RES renewable energy credit requirements to demonstrate compliance with the Annual Renewable Energy Requirement for 2025. The proposed plan also notifies the ACC that continued evaluation and approval of the pending 2024 and 2025 RES Implementation Plans is no longer necessary. On February 4, 2026, the ACC approved APS's 2026 RES Implementation Plan.

On April 22, 2025, the ACC approved APS's request to refund uncommitted DSMAC and RES surcharge funds of approximately $9 million and $43 million, respectively, with final amounts subject to adjustment dependent upon billed usage. Refunds were issued during July and August of 2025 totaling $7.6 million for DSMAC and $44.2 million for RES.

On July 1, 2026, APS filed its 2027 RES Implementation Plan and proposed a budget of approximately $120.9 million, excluding any funding offsets. The budget for the Implementation Plan consists of funding for existing contractual commitments and other regulatory obligations arising from RES compliance. APS anticipates a reduction in RES charges in 2027 based on prior customer revenues collected that have not been allocated for program implementation, coupled with revenue from renewable energy credit sales. Additionally, APS is seeking approval of the renewable generation waiver until further order by the ACC to eliminate APS's requirement to own and retire renewable energy credits to demonstrate compliance with the RES standard. APS cannot predict the outcome of this matter.

As discussed below in "Energy Modernization Plan," on August 14, 2025, the ACC voted to send a full repeal of the RES rules to the Secretary of State for publication. See below for more information.

APS has a Green Power Partners Program that allows customers to pay a specified price to receive a contracted amount of green power in addition to their normal rate in order to support those customers in meeting their individual sustainability goals. On June 28, 2024, APS filed an application for approval of modifications to the Green Power Partners Program and requested a renewable energy credit waiver. On February 4, 2026, the ACC approved APS's proposed changes to the Green Power Partners Program, including modifications to pricing structures for participating customers.

Demand Side Management Adjustor Charge

The ACC Electric Energy Efficiency Standards require APS to submit a DSM Implementation Plan at least every odd year for review and approval by the ACC. Verified energy savings from APS's resource savings projects can be counted toward compliance with the Electric Energy Efficiency Standards; however, APS is not allowed to count savings from systems savings projects toward determination of the achievement of performance incentives, nor may APS include savings from these system savings projects in the calculation of its LFCR mechanism. See below for discussion of the LFCR.

On November 30, 2022 and May 31 2023, APS filed its 2023 DSM Implementation Plan, which requested a budget of $88 million, and an amended 2023 DSM Implementation Plan, respectively. Subsequent to filing the amended 2023 DSM Implementation Plan and prior to the ACC approving it, on November 30, 2023, APS filed its 2024 DSM Implementation Plan. The 2024 DSM Implementation Plan requested a total budget of $91.5 million and incorporated all elements of the amended 2023 DSM Implementation Plan as well as the 2024 Transportation Electrification Implementation Plan. On April 26, 2024 and June 20, 2025, APS filed amendments to the 2024 DSM Implementation Plan. The Second Amended 2024 DSM Implementation Plan, compared to the initially filed plan, supported an updated budget of $90.9 million, which reflected (i) removal of incentive funds for the Level 2 Smart Charger rebate within the EV Charging Demand Management Pilot, (ii) exclusion of the proposed tranches two and three of the Residential Battery Pilot, and inclusion of the newly approved Bring-Your-Own-Device Battery ("BYOD") Pilot described below, and (iii) an update on the performance incentive calculation. On May 16, 2025, APS filed a request with the ACC to extend the deadline to file its 2026 DSM Implementation Plan until 120 days after the ACC acts on its Second Amended 2024 DSM Implementation Plan. On July 9, 2025, the ACC approved APS's extension request. On December 3, 2025, the ACC voted to reduce the budget of the DSM program to $40 million and discontinue several programs and customer rebates while promoting the expansion of Virtual Power Plant programs. On April 7, 2026, APS filed an updated DSM and Transportation Electrification Plan consistent with recent ACC orders.

On August 30, 2024, APS filed an application for a new BYOD Battery Pilot Plan of Administration with the ACC as required by Decision No. 79293. This plan would allow APS to work with residential customers to enable APS to dispatch participating batteries and use them to provide demand response capacity to the grid. On March 20, 2025, the ACC approved the BYOD Plan of Administration.

As discussed above under “Renewable Energy Standard,” APS refunded uncommitted DSMAC funds during July and August 2025 totaling $7.6 million for DSMAC.

As discussed below in “Energy Modernization Plan,” on September 17, 2025, the ACC voted to send a full repeal of the EES rules to the Secretary of State for publication. See below for more information.

Power Supply Adjustor Mechanism and Balance

The PSA provides for the adjustment of retail rates to reflect variations primarily in retail fuel and purchased power costs. The PSA is subject to specified parameters and procedures, including the following:

- APS records deferrals for recovery or refund to the extent actual retail fuel and purchased power costs vary from Base Fuel Rate;
- an adjustment to the PSA rate is made annually each February 1 (unless otherwise approved by the ACC) and goes into effect automatically unless suspended by the ACC;
- the PSA uses a forward-looking estimate of fuel and purchased power costs to set the annual PSA rate, which is reconciled to actual costs experienced for each PSA Year (February 1 through January 31) (see the following bullet point);
- the PSA rate includes (a) a “forward component,” under which APS recovers or refunds differences between expected fuel and purchased power costs for the upcoming calendar year and those embedded in the Base Fuel Rate; (b) a “historical component,” under which differences between actual fuel and purchased power costs and those recovered or refunded through the combination of the Base Fuel Rate and the forward component are recovered during the next PSA Year; and (c) a “transition component,” under which APS may seek mid-year PSA changes due to large variances between actual fuel and purchased power costs and the combination of the Base Fuel Rate and the forward component; and
- the PSA rate may not be increased or decreased more than $0.006 per kWh in a year without permission of the ACC.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the changes in the deferred fuel and purchased power regulatory asset (liability) (dollars in thousands):

	Six Months Ended June 30,	
	2026	2025
Balance at beginning of period	$ 149,068	$ 287,597
Deferred fuel and purchased power costs	69,325	95,850
Amounts charged to customers	(279,830)	(201,035)
Balance at end of period	$ (61,437)	$ 182,412

In Decision No. 79293 in the 2022 Rate Case, the ACC approved a permanent increase in the annual PSA adjustor rate cap from $0.004 per kWh to $0.006 per kWh and a requirement that APS report to the ACC for possible action when the overall PSA balance reaches $100 million. As part of the 2022 Rate Case decision, the ACC also approved an overall PSA rate of $0.011977 per kWh, which consisted of a forward component of $(0.012624) per kWh, a historical component of $0.013071 per kWh, and a transition component of $0.011530 per kWh. The overall PSA rate was reduced to offset an increase in base fuel prices. The rate became effective on March 8, 2024.

On November 27, 2024, APS filed its PSA rate for the PSA year beginning February 1, 2025. The overall PSA rate of $0.013977 per kWh consists of a forward component of $(0.000281) per kWh, a historical component of $0.008728 per kWh, and a transition component of $0.005530 per kWh. This overall PSA rate is an increase of $0.002 per kWh over the prior overall rate approved in the 2022 Rate Case decision, and it is below the annual PSA rate increase cap of $0.006 per kWh. On February 5, 2025, the ACC voted to approve this request, with a rate effective date of the first billing cycle in March 2025.

On November 26, 2025, APS filed its PSA rate for the PSA year beginning February 1, 2026. The overall PSA rate of $0.016977 per kWh consists of a forward component of $0.012457 per kWh, a historical component of $0.00452 per kWh, and no transition component. This overall PSA rate is an increase of $0.003 per kWh over the prior approved rate, and it is below the annual PSA rate increase cap of $0.006 per kWh. The rate became effective the first billing cycle of February 2026.

Transmission Rates, Transmission Cost Adjustor, and Other Transmission Matters

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

Effective June 1, 2024, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $27.4 million for the 12-month period beginning

June 1, 2024 in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by approximately $16.6 million and retail customer rates would have increased by approximately $10.8 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC-approved balancing account, the retail revenue requirement increased by $8.8 million, resulting in an increase to residential rates and commercial rates over 3 MW and a decrease to commercial rates less than or equal to 3 MW. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2024.

Effective June 1, 2025, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $119.0 million for the 12-month period beginning June 1, 2025, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by approximately $4.6 million and retail customer rates would have increased by approximately $114.4 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC-approved balancing account, the retail revenue requirement increased by $88.3 million, resulting in increases to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2025.

Effective June 1, 2026, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $13.1 million for the 12-month period beginning June 1, 2026, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by approximately $1.5 million and retail customer rates would have increased by approximately $11.6 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC-approved balancing account, the retail revenue requirement increased by $20.6 million, resulting in increases to both residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2026.

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 adjustment to the LFCR has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWhs lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. DG sales losses are determined from the metered output from the DG units.

On March 8, 2024, APS filed conforming LFCR schedules to incorporate changes required as a result of Decision No. 79293 in the 2022 Rate Case. On April 9, 2024, the ACC approved the 2023 annual LFCR adjustment, with new rates effective in the first billing cycle of May 2024.

On June 5, 2024, APS filed a revised LFCR Plan of Administration in accordance with Decision No. 79293. The ACC approved the revised Plan of Administration on October 8, 2024.

On July 31, 2024, APS filed its 2024 annual LFCR adjustment, requesting that effective November 1, 2024, the annual LFCR recovery amount be increased to $49.6 million (an $8 million increase from previous levels). On December 3, 2024, the ACC approved the 2024 annual LFCR adjustment, with new rates effective in the first billing cycle of January 2025.

On July 31, 2025, APS filed its 2025 annual LFCR adjustment, requesting that effective November 1, 2025, the annual LFCR recovery amount be increased to $60.1 million (a $10.5 million increase from previous levels). On November 21, 2025, the ACC approved the 2025 annual LFCR adjustment, with new rates effective in the first billing cycle of December 2025.

On July 31, 2026, APS filed its 2026 annual LFCR adjustment, requesting that effective November 1, 2026, the annual LFCR recovery amount be increased to $72.5 million (a $12.4 million increase from previous levels). APS cannot predict the outcome of this matter.

Tax Expense Adjustor Mechanism

The TEAM helps address potential federal income tax reform and enables the pass-through of certain income tax effects to customers. The TEAM expressly applies to APS's retail rates with the exception of a small subset of customers taking service under specially-approved tariffs. Currently, the TEAM is set to a zero rate as per ACC Decision No. 79293.

Court Resolution Surcharge

Following an appeal of the 2019 Rate Case decision, the ACC approved a Court Resolution Surcharge ("CRS") mechanism that permits APS to recover certain costs associated with investments and expenses for APS's purchase and installation of selective catalytic reduction ("SCR") technology for Four Corners Units 4 and 5 and a change in APS's allowable return on equity as required by the Arizona Court of Appeals and approved by the ACC in Decision No. 78979. The CRS went into effect on July 1, 2023, at a rate of $0.00175 per kWh. The rate is designed to recover $59.6 million in revenue lost by APS between December 2021 and June 20, 2023, and the prospective recovery of ongoing costs related to the SCR investments and expense and the allowable return on equity difference in current base rates. The portion of the CRS representing the recovery of the $59.6 million of lost revenue between December 2021 and June 20, 2023, $51.6 million of which has been collected as of June 30, 2026, will cease upon full collection of the lost revenue. Additionally, the CRS tariff was updated to remove the return on equity component and account for SCR-related depreciation and deferral adjustments approved in Decision No. 79293 in the 2022 Rate Case.

Solar Export Price

Payments by APS for energy exported to the grid from residential DG solar facilities are determined using a Resource Comparison Proxy ("RCP") methodology as determined in the ACC's generic Value and Cost of DG docket. The RCP is a method that is based on the most recent five-year rolling average price that APS incurs for utility-scale solar photovoltaic projects. The price established by this RCP method is updated annually (between general retail rate cases) but cannot be decreased by more than 10% per year.

On May 1, 2024, APS filed an application for revisions to the RCP. This application would decrease the RCP price to $0.06857 per kWh, reflecting a 10% annual reduction, to become effective September 1, 2024. On August 13, 2024, the ACC approved the RCP as filed.

On May 1, 2025, APS filed an application for revisions to the RCP. This application would decrease the RCP price to $0.06171 per kWh, reflecting a 10% annual reduction, to become effective September 1, 2025. On August 14, 2025, the ACC approved the RCP as filed.

On May 1, 2026, APS filed an application for revisions to the RCP. This application requests a decrease to the RCP price to $0.05554 per kWh, reflecting a 10% annual reduction, to become effective September 1, 2026. APS cannot predict the outcome of this matter.

On October 11, 2023, the ACC voted to open a new general docket to hold a hearing to explore potential future changes to the 10% annual reduction cap in the solar export rate paid by utilities to distributed solar customers for exports to the grid and the 10-year rate lock period for those customers that were approved in the ACC's Value and Cost of DG Docket. Following various conferences, the ACC Staff filed a report finding that the RCP is working as intended and recommending no changes at this time along with closure of the docket. On October 6, 2025, the ACC administratively closed the general docket, and APS expects no additional action in this matter.

Energy Modernization Plan

On May 26, 2023, the ACC opened a new docket to review the Arizona Administrative Code related to Resource Planning, the RES, and EES. On January 9, 2024, the ACC approved the opening of new dockets to begin rulemaking process for EES and RES. It was also ordered that an existing rulemaking docket would be utilized to review proposed updates to the ASRFP and Resource Planning Rules. During an ACC Open Meeting on February 6, 2024, the ACC approved motions to direct ACC Staff to include recommendations to repeal the current EES and RES rules during the rulemaking process. On August 21, 2024, the ACC Staff filed separate reports for each set of rules, including its recommendations to repeal the EES and RES rules along with required preliminary economic, small business, and consumer impact statements. APS and other interested parties have filed comments about the ACC Staff reports.

The ACC voted to send to the Secretary of State full repeals of the RES and EES rules on August 14, 2025 and September 17, 2025, respectively, for publication and to begin the public rulemaking process. On March 4, 2026, the ACC approved the ROO to repeal the RES Rules and directed Staff to create and file with the Office of the Attorney General a Notice of Final Rulemaking package. Both the Sierra Club and the State of Arizona Attorney General's Office filed a request for rehearing of Decision No. 81677 on March 30, 2026. On April 2, 2026, a Notice of Final Rulemaking and Final Economic Impact Statement was delivered to the Attorney General's Office. In response to this Notice, the Attorney General's Office notified the Commission that it was rejecting the rulemaking implementing the RES repeal for failure to follow required procedural steps. The ACC has since directed its Legal Division to pursue legal action challenging this rejection. On July 8, 2026, the ACC repealed the EES Rules effective immediately, instructing ACC Staff to submit a Notice of Final Rulemaking to the Arizona Secretary of State. APS cannot predict the outcome of this matter.

Integrated Resource Plan

ACC rules require utilities to develop triennial 15-year IRPs which describe how the utility plans to serve customer load in the plan time frame. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. In February 2022, the ACC acknowledged APS's 2020 IRP filed on June 26, 2020. The ACC also approved certain amendments to the

IRP process, including setting an EES of 1.3% of retail sales annually (averaged over a three-year period) and a demand-side resource capacity of 35% of 2020 peak demand by January 1, 2030.

On November 1, 2023, APS filed its 2023 IRP and on October 8, 2024, the ACC acknowledged APS's 2023 IRP and approved certain amendments to the IRP process, including requirements for APS to demonstrate system resource adequacy as well as analysis of impacts from western market participation and planned resource requirements in the next IRP, which is due to be filed on October 30, 2026.

Residential Electric Utility Customer Service Disconnections

In accordance with the ACC's service disconnection rules, APS uses a calendar-based method to suspend the disconnection of residential customers for nonpayment from June 1 through October 15 each year ("Annual Disconnection Moratorium"). In addition, APS temporarily pauses shutting off residential customers for nonpayment in locations where the following day's temperature is forecasted to be 95°F or higher or 32°F or lower according to the U.S. National Weather Service website. Since the Annual Disconnection Moratorium began, APS has experienced an increase in bad debt expense and the related write-offs of delinquent customer accounts. Customers with past due balances of $75 or greater as the Annual Disconnection Moratorium nears its end are automatically placed on six-month payment arrangements prior to beginning the disconnection process.

Cholla Power Plant

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

On August 14, 2024, APS filed a request with the ACC for a deferral order associated with unrecovered book value and decommissioning and site remediation costs of Cholla Units 1 and 3 related to the cessation of coal-burning operations at Cholla in April 2025. This order would authorize APS to defer for future recovery in rates the expenses necessary to cease operating coal-fired power plant infrastructure at Cholla, including legally required site environmental remediation, CCR corrective actions, the closure of CCR management facilities, and any unrecovered plant investment and operating costs incurred through and after April 2025. On July 8, 2025, APS withdrew its deferral application, requesting that the costs that would have been covered in the deferral order request instead be addressed in the 2025 Rate Case.

APS ceased coal-burning operations at Cholla in March 2025 and formally retired Cholla Units 1 and 3 on April 30, 2025. Upon the cessation of coal-fired operations, APS had approximately $81 million of remaining net-book value associated with Units 1 and 3 plant assets. APS is currently recovering in rates a return on the net-book value of its interest in Cholla and associated depreciation costs. In the 2025 Rate Case, APS has requested recovery in rates of the ongoing environmental remediation and CCR closure costs associated with Cholla and any remaining unrecovered plant costs. The 2025 Rate Case also includes a request for an ongoing deferral order relating to anticipated increased environmental remediation costs relating to Cholla that may be incurred after the 2025 Rate Case proceeding. APS cannot predict the outcome of this matter.

For Cholla Unit 2, APS has been allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs, totaling $21.3 million as of June 30, 2026, in addition to a return on its investment. In the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to regulatory assets. In accordance with the 2019 Rate Case decision, the regulatory asset is being amortized through 2033.

On July 2, 2026, APS announced plans to convert two units at Cholla to natural gas, adding approximately 380 MW of gas-fired generation. The plan is subject to change pending the comparison to other generation sources that APS is considering in its evaluation of the 2025 ASRFP. The plan contemplates that construction on the gas conversion would begin in 2028 with targeted in-service dates beginning in 2029. Future regulatory and environmental reviews of the proposed conversion will be required. APS cannot predict the outcome of this matter.

Navajo Plant

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

APS has been recovering a return on and of the net book value of its interest in the Navajo plant in base rates over its previously estimated life through 2026. Pursuant to the 2019 Rate Case decision described above, APS will be allowed continued recovery of the book value of its remaining investment in the Navajo Plant, $19.0 million as of June 30, 2026, in addition to a return on the net book value, with the exception of 15% of the annual amortization expense in rates. In addition, APS will be allowed recovery of other costs related to retirement and closure, including the Navajo coal reclamation regulatory asset, $0.4 million as of June 30, 2026. The disallowed recovery of 15% of the annual amortization does not have a material impact on APS financial statements.

Fire Mitigation

On August 14, 2024, APS filed a request with the ACC for a deferral order that would authorize APS to defer, for future recovery in rates, operations and maintenance expenses associated with wildfire management, including increased insurance costs. On June 18, 2025, the ACC denied APS's request and recommended that wildfire related expenses be recovered in APS's 2025 Rate Case.

On May 12, 2025, the Arizona governor signed into law a bill that requires Arizona electric utilities to develop and seek approval for wildfire mitigation plans and defines the standard of care with respect to wildfire-related claims by reference to such plans.

On February 1, 2026, APS submitted its 2026 Comprehensive Wildfire Mitigation Plan for approval to the Department of Forestry and Fire Management, which approved APS's plan on May 7, 2026.

Regulatory Assets and Liabilities

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

	Amortization Through	June 30, 2026	December 31, 2025
Pension	(a)	$ 712,234	$ 723,042
Income taxes — AFUDC equity	2055	209,567	203,890
Palo Verde sale leaseback noncontrolling interests' acquisition (b)	N/A	151,506	151,506
Ocotillo deferral	2034	92,509	99,931
Lease incentive (Note 17)	2046	92,330	90,005
Deferred fuel and purchased power — mark-to-market (Note 10)	2030	78,831	29,330
SCR deferral (c)	2038	74,217	77,186
Retired power plant costs	2031	47,312	56,809
Income taxes — investment tax credit basis adjustment (Note 5)	2056	41,691	42,459
Deferred compensation	2036	32,842	32,204
FERC transmission true up	2028	22,219	21,471
Deferred property taxes	2027	11,064	15,349
Palo Verde VIEs (Note 9)	2046	9,085	8,582
Mead-Phoenix transmission line — contributions in aid of construction	2050	7,886	8,052
Loss on reacquired debt	2038	5,180	5,653
Active union medical trust	(e)	4,966	3,696
TEAM (c)	2031	3,551	3,879
PSA - interest	2027	769	5,679
Navajo coal reclamation	2026	361	2,516
Deferred fuel and purchased power (c) (d)	2027	—	149,068
DSM (c)	2026	—	15,706
Other	Various	3,314	3,353
Total regulatory assets (f)		$ 1,601,434	$ 1,749,366
Less: current regulatory assets		$ 150,106	$ 286,009
Total non-current regulatory assets		$ 1,451,328	$ 1,463,357

(a) This asset represents the future recovery of pension benefit obligations and expense through retail rates. If these costs are disallowed by the ACC, this regulatory asset would be charged to other comprehensive income/loss and result in lower future revenues. The 2022 Rate Case decision allows for the full return on the pension asset in rate base. See Note 8 for further discussion.
(b) This asset relates to the purchase of previously leased interest in Palo Verde Unit 2. See Note 9.
(c) See "Cost Recovery Mechanisms" discussion above.
(d) Subject to a carrying charge.
(e) Collected in retail rates.
(f) There are no regulatory assets for which the ACC has allowed recovery of costs, but not allowed a return by exclusion from rate base. FERC rates are set using a formula rate as described in "Transmission Rates, Transmission Cost Adjustor, and Other Transmission Matters."

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

	Amortization Through	June 30, 2026	December 31, 2025
Excess deferred income taxes - ACC — Tax Cuts and Jobs Act (a)	2046	$ 832,335	$ 847,572
Excess deferred income taxes - FERC — Tax Cuts and Jobs Act (a)	2058	197,492	200,161
AROs and removal costs	(b)	298,964	286,907
Other postretirement benefits	(c)	226,529	233,952
Four Corners coal reclamation	2038	97,048	97,988
Income taxes — deferred investment tax credit	2056	80,553	81,949
Deferred fuel and purchased power (d) (e)	2027	61,437	—
Income taxes — change in state rates	2054	55,201	56,260
RES (d)	2027	56,847	54,551
Sundance maintenance	2031	25,969	25,668
Spent nuclear fuel	2027	16,928	20,492
DSM (d)	2026	12,498	26,228
TCA Balancing Account (d)	2028	10,654	4,860
TEAM (d)	2032	3,436	3,738
Deferred fuel and purchased power — mark-to-market (Note 10)	2030	—	3,641
Other	Various	1,977	3,063
Total regulatory liabilities		$ 1,977,868	$ 1,947,030
Less: current regulatory liabilities		$ 194,643	$ 210,909
Total non-current regulatory liabilities		$ 1,783,225	$ 1,736,121

(a) For purposes of presentation on the Statements of Cash Flows, amortization of the regulatory liabilities for excess deferred income taxes are reflected as "Deferred income taxes" under Cash Flows From Operating Activities.
(b) In accordance with regulatory accounting, APS accrues removal costs for its regulated assets, even if there is no legal obligation for removal.
(c) See Note 8.
(d) See "Cost Recovery Mechanisms" discussion above.
(e) Subject to a carrying charge.

8. Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan, a non-qualified supplemental excess benefit retirement plan, and other postretirement benefit plans for the employees of Pinnacle West and our subsidiaries. The other postretirement benefit plans include a group life and medical plan and a post-65 retiree health reimbursement arrangement ("HRA"). Pinnacle West uses a December 31 measurement date each year for its pension and other postretirement benefit plans. Our plan assets are measured at fair value as of the measurement date.

The following table provides detail 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 Plans				Other Benefits Plans			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025	2026	2025	2026	2025
Service cost-benefits earned during the period	$ 11,684	$ 11,127	$ 23,783	$ 22,076	$ 2,140	$ 2,059	$ 4,377	$ 4,041
Non-service costs (credits):								
Interest cost on benefit obligation	37,292	38,584	74,904	77,560	4,931	5,070	9,910	10,172
Expected return on plan assets	(44,365)	(44,849)	(88,461)	(89,396)	(12,719)	(12,142)	(25,438)	(24,284)
Amortization of:								
Prior service cost (credit)	151	—	302	—	—	—	—	(1,265)
Net actuarial loss (gain)	10,443	11,248	21,596	23,366	(2,746)	(2,965)	(5,446)	(5,864)
Net periodic benefit costs (credits)	$ 15,205	$ 16,110	$ 32,124	$ 33,606	$ (8,394)	$ (7,978)	$ (16,597)	$ (17,200)
Portion of costs (credits) charged to expense	$ 8,262	$ 9,365	$ 17,780	$ 19,826	$ (6,644)	$ (6,399)	$ (13,153)	$ (13,272)

Contributions

Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. The expected minimum required cash contributions for the pension plan are zero for the next three years. However, while we do not expect to make a voluntary contribution in 2026, we are evaluating whether to make voluntary contributions in 2027 and 2028. The amount of voluntary contributions will be determined as we continue to evaluate and assess our ongoing contribution strategy. Regarding contributions to our other postretirement benefit plan, we have not made a contribution year-to-date in 2026 and do not expect to make any contributions in 2026, 2027 or 2028. The Company was reimbursed $23 million in April 2026 for prior year's retiree medical claims from the other postretirement benefit plan trust assets.

9. Variable Interest Entities

Pinnacle West

Captive Insurance Cell VIE

To support our overall insurance program, Pinnacle West established a captive insurance cell to insure certain risks of Pinnacle West and our subsidiaries. The Captive is a protected separate cell captive insurance company sponsored by Energy Insurance Services, Inc. ("EISI"). EISI is owned by Energy Insurance Mutual Limited Company and allows participating member sponsoring organizations, such as Pinnacle West, to insure risks using captive entities. Pinnacle West, through its contractual rights, has a controlling financial interest in the separate protected Captive cell's assets. Pinnacle West obtains all the benefits from the Captive and makes all the primary controlling decisions that economically impact the Captive. As a separate protected cell, Pinnacle West is the Captive's only participant. The Captive is a VIE for which Pinnacle West is the primary beneficiary. Accordingly, Pinnacle West consolidates the Captive.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Under a mutual business program participation agreement between the Captive and EISI, EISI will issue policies, make claim disbursements, claim expenses and other underwriting fees on behalf of the Captive, as necessary.

The Captive insures Pinnacle West and its subsidiaries for terrorism coverage, excess liability including certain wildfire coverage, excess property insurance, and excess employment practice liability. The Captive policies exclude nuclear liability at Palo Verde. See Note 11 for details regarding nuclear liability insurance. Claim payments to the insureds can only be made up to the amount of the Captive's available assets. In the event that claims exceed the Captive's available assets, Pinnacle West may be required to provide additional funding to the Captive. In addition to policies obtained through the Captive, Pinnacle West also has commercial and mutual insurance policies purchased through third-party insurers that may provide coverage if a loss event occurs.

As a result of consolidation, we eliminate intercompany transactions between Pinnacle West and the Captive and record the Captive's assets, liabilities and third-party operating activities. In consolidation, the Captive's insurance premium revenues derived from Pinnacle West policies are eliminated against the insurance premium expense recorded by Pinnacle West and our subsidiaries relating to insurance policy coverage provided by the Captive. Consolidation primarily resulted in Pinnacle West reflecting the Captive's investment holdings on its Condensed Consolidated Balance Sheets, and the Captive's investment gains and losses reflected through earnings on Pinnacle West's Condensed Consolidated Statements of Income.

Consolidation of the Captive resulted in an increase in Pinnacle West's net income for the three and six months ended June 30, 2026 of $4.1 million and $4.4 million, respectively, and for the three and six months ended June 30, 2025 of $1.7 million and $2.4 million, respectively. Amounts are fully attributable to Pinnacle West shareholders. Consolidation impacts the Pinnacle West Condensed Consolidated Statements of Income operations and maintenance expense, other income, and other expense line items.

Pinnacle West's Condensed Consolidated Balance Sheets as of June 30, 2026 and December 31, 2025 include $46 million and $40 million, respectively, of assets relating to the Captive that is reported within the other special use funds line item. See Notes 14 and 15 for additional details on these investment holdings.

APS's financial statements are not impacted by Pinnacle West's consolidation of the Captive VIE.

APS

Palo Verde Sale Leaseback VIEs

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. In September 2025, APS purchased two of the three leased interests, the two related lease agreements were terminated and VIE consolidation treatment was discontinued for those two leases. Due to the purchases, APS now owns these previously leased interests, providing APS a total ownership interest in Palo Verde Unit 2 of 23.9%. APS's remaining leased interest in Palo Verde Unit 2 is approximately 5.2%. See Note 12 in the 2025 Form 10-K for additional details regarding the two purchased leases.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As of June 30, 2026, one VIE lease arrangement remains in effect. The VIE lease agreement that was not subject to the purchase agreements is not impacted by the purchase transactions, and APS continues to consolidate this lessor VIE.

Under the current remaining lease, in effect through 2033, APS will be required to make payments relating to the lease in total of approximately $9 million annually for the period 2026 through 2033. At the end of the lease period, APS will have the option to purchase the leased asset at its fair market value, extend the lease for up to two years, or return the asset to the lessor. The lease terms give APS the ability to utilize the asset for a significant portion of the asset's economic life, and therefore provide APS with the power to direct activities of the VIE that most significantly impact the VIE's economic performance. Predominantly due to the lease terms, APS has been deemed the primary beneficiary of this VIE and therefore consolidates the VIE.

As a result of consolidation, we eliminate lease accounting and instead recognize depreciation expense, resulting in an increase in net income for the three and six months ended June 30, 2026 of $2 million and $4 million, respectively, and for the three and six months ended June 30, 2025 of $4 million and $9 million, respectively. The increase in net income is entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

Our Condensed Consolidated Balance Sheets include the following amounts relating to the VIE (dollars in thousands):

	June 30, 2026	December 31, 2025
Palo Verde sale leaseback property, plant and equipment, net of accumulated depreciation	$ 31,248	$ 32,035
Equity — Noncontrolling interests	40,333	40,617

Assets of the VIE 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 the VIE upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, 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 VIE's noncontrolling equity participants and take title to the leased Unit 2 interest, which, if appropriate, may be required to be written-down in value. If such an event were to occur during the lease period, APS may be required to pay the noncontrolling equity participant approximately $177 million in 2026 and up to $267 million over the lease term.

For regulatory ratemaking purposes, the lease agreement continues to be treated as an operating lease, and as a result, we have recorded a regulatory asset relating to the arrangement.

10. Derivative Accounting

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

Our derivative instruments, excluding those qualifying for a scope exception, are recorded on the Condensed Consolidated Balance Sheets as an asset or liability and are measured at fair value. See Note 14 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.

See Note 13 for details relating to Pinnacle West's equity forward sale agreements and convertible notes. These equity-linked transactions are indexed to Pinnacle West common stock and qualify for a derivative scope exception and as such are not subject to mark-to-market accounting and are excluded from the derivative disclosures below.

Energy Derivatives

For its regulated operations, APS defers for future rate treatment 100% of the unrealized gains and losses on energy derivatives pursuant to the PSA mechanism that would otherwise be recognized in income. Realized gains and losses on energy derivatives are deferred in accordance with the PSA to the extent the amounts are above or below the Base Fuel Rate. See Note 7. Gains and losses from energy derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

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

		Quantity	
Commodity	**Unit of Measure**	**June 30, 2026**	**December 31, 2025**
Power	Gigawatt-hour	408	542
Gas	Billion cubic feet	246	211

Gains and Losses from Energy Derivative Instruments

For the three and six months ended June 30, 2026 and 2025, APS had no energy derivative instruments in designated accounting hedging relationships.

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

Commodity Contracts	Financial Statement Location	Three Months Ended June 30, 2026	Three Months Ended June 30, 2025	Six Months Ended June 30, 2026	Six Months Ended June 30, 2025
Net Gain (Loss) Recognized in Income	Fuel and purchased power (a)	$ (30,855)	$ (75,934)	$ (56,752)	$ 40,770

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

Energy Derivative Instruments in the Condensed Consolidated Balance Sheets

Our energy derivative transactions are typically executed under standardized or customized agreements, which include collateral requirements and, in the event of a default, would allow for the netting of positive and negative exposures associated with a single counterparty. Agreements that allow for the offsetting of positive and negative exposures associated with a single counterparty are considered master netting arrangements. Transactions with counterparties that have master netting arrangements are offset and reported net on the Condensed Consolidated Balance Sheets. Transactions that do not allow for offsetting of positive and negative positions are reported gross on the Condensed Consolidated Balance Sheets.

We do not offset a counterparty's current energy derivative contracts with the counterparty's non-current energy derivative contracts, although our master netting arrangements would allow current and non-current positions to be offset in the event of a default. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, trade receivables and trade payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting tables presented below.

The following tables provide information about the fair value of APS's risk management activities reported on a gross basis and the impacts of offsetting. These amounts relate to commodity contracts and are located in the assets and liabilities from risk management activities lines of APS's Condensed Consolidated Balance Sheets (dollars in thousands):

As of June 30, 2026	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amounts Reported on Balance Sheets
Current assets	$ 782	$ (782)	$ —	$ 5	$ 5
Investments and other assets	1,230	(1,230)	—	—	—
Total assets	2,012	(2,012)	—	5	5
Current liabilities	(69,470)	782	(68,688)	(2,296)	(70,984)
Deferred credits and other	(11,373)	1,230	(10,143)	—	(10,143)
Total liabilities	(80,843)	2,012	(78,831)	(2,296)	(81,127)
Total	$ (78,831)	$ —	$ (78,831)	$ (2,291)	$ (81,122)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to or received by counterparties that is subject to offsetting.
(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $2,296 thousand and cash margin provided to counterparties of $5 thousand.

As of December 31, 2025	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amounts Reported on Balance Sheets
Current assets	$ 12,640	$ (9,395)	$ 3,245	$ 5	$ 3,250
Investments and other assets	6,707	(1,570)	5,137	—	5,137
Total assets	19,347	(10,965)	8,382	5	8,387
Current liabilities	(41,970)	9,395	(32,575)	(2,566)	(35,141)
Deferred credits and other	(3,065)	1,570	(1,495)	—	(1,495)
Total liabilities	(45,035)	10,965	(34,070)	(2,566)	(36,636)
Total	$ (25,688)	$ —	$ (25,688)	$ (2,561)	$ (28,249)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to or received by counterparties that is subject to offsetting.
(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $2,566 thousand and cash margin provided to counterparties of $5 thousand.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by energy derivative counterparties and have risk management contracts with many energy derivative counterparties. As of June 30, 2026, we have no counterparties with positive exposure greater than 10% of Pinnacle West's $5 thousand of net 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 results of operations 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 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 energy 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 energy derivative instruments in a net liability position, with investment grade credit contingencies, the counterparties could demand additional collateral if our debt credit rating were to fall below investment grade (below BBB- for Standard & Poor's or Fitch or Baa3 for Moody's).

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

	June 30, 2026
Aggregate fair value of derivative instruments in a net liability position	$ 80,843
Additional collateral in the event credit-risk related contingent features were fully triggered (a)	52,202

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

As of June 30, 2026, 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 $711 million if our debt credit ratings were to fall below investment grade.

11. 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 DOE in the 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, 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, which required DOE to pay the Palo Verde owners for certain specified costs paid by Palo Verde during the period January 1, 2007, through June 30, 2011. In addition, the settlement agreement provided APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2016, which was extended to December 31, 2025. APS is currently in the process of pursuing an extension of the settlement to cover costs paid through December 31, 2028.

APS has recovered costs paid from July 1, 2011, through October 31, 2025, for twelve claims pursuant to the terms of the August 15, 2014 settlement agreement. The DOE has approved and paid approximately $189.7 million for these claims (APS's share is approximately $55.2 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 ACC's decision from the 2017 rate case, this regulatory liability is being refunded to customers.

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. This insurance limit is subject to an adjustment every five years based upon the aggregate percentage change in the Consumer Price Index. The most recent adjustment took effect on January 1, 2024. As of that date, in accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident up to approximately $16.3 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $500 million, which is provided by American Nuclear Insurers. The remaining balance of approximately $15.8 billion of liability coverage is provided through a mandatory, industry-wide retrospective premium program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be responsible for retrospective premiums. The maximum retrospective premium per reactor under the program for each nuclear liability incident is approximately $165.9 million, subject to a maximum annual premium of approximately $24.7 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 $144.9 million, with a maximum annual retrospective premium of approximately $21.6 million.

The Palo Verde participants maintain insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion. APS has also secured accidental outage insurance for a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and accidental outage insurance are provided by 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 $24.9 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. Additionally, at the sole discretion of the NEIL Board of Directors, APS would be liable to provide approximately $68.9 million in deposit premium within 20 days of request as assurance to satisfy any site obligation of retrospective premium assessment. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions, sublimits, and exclusions.

Nuclear Wage Class Action Lawsuit

On July 11, 2025, APS, together with all 25 other U.S. nuclear power plant operators, was named in a class action lawsuit brought in the U.S. District Court in Maryland. The lawsuit alleges the country's nuclear operators have violated antitrust laws by agreeing to exchange compensation information and suppress compensation. The class action complaint has been brought on behalf of all persons employed in nuclear power generation in the U.S. from May 1, 2003 until the present and alleges violations of the Sherman Act. We are unable at this time to predict the outcome of this matter and whether it will have a material impact on our financial position, results of operations, or cash flows.

Captive Insurance Cell

Pinnacle West has established a captive insurance program to supplement commercial and mutual insurance coverage for certain risks. The Captive insures Pinnacle West and its subsidiaries for terrorism coverage, excess liability including certain wildfire coverage, excess property insurance, and excess employment practice liability. These coverages may be supplemented with commercial and mutual insurance coverage. The Captive policies exclude nuclear liability at Palo Verde. The Captive may hold investment assets in cash, cash equivalents, and equity and fixed income instruments, which in the event of an insured loss would be available to pay covered claims. In the event of an insured loss event, Pinnacle West may be required to provide additional funding to the Captive. The Captive is a VIE, and Pinnacle West is the primary beneficiary of the VIE and consolidates the assets and liabilities of the Captive. In addition to the policies obtained through the Captive, Pinnacle West also has commercial and mutual insurance policies purchased through third-party insurers that may provide coverage if a loss event occurs. See Note 9 for additional details.

Fuel and Purchased Power Commitments and Purchase Obligations

As of June 30, 2026, our fuel and purchased power and purchase obligation commitments have increased by $2.9 billion from the information provided in our 2025 Form 10-K, primarily due to gas tolling lease contracts. See Note 17.

Other than the items described above, there have been no material changes, as of June 30, 2026, outside the normal course of business in contractual obligations from the information provided in our 2025 Form 10-K. See Note 6 for discussion regarding changes in our short-term and long-term debt obligations.

Superfund and Other Related Matters

CERCLA establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who released, generated, transported to, or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible (each a "PRP"). PRPs may be strictly, jointly, and severally liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, 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 RI/FS. The RI/FS for OU3 was finalized and submitted to EPA at the end of 2022. EPA notified APS that the remedial investigation and feasibility study ("RI/FS") was approved on September 11, 2024. On September 25, 2025, EPA executed a final ROD adopting the OU3 remedies proposed in the approved RI/FS OU3. APS's expenditures related to this investigation and study are approximately $3 million. APS anticipates it may incur additional expenditures in the future, but because the final costs associated with remediation requirements set forth in the RI/FS and ROD are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated; however, APS does not expect the outcome to have a material impact on its financial position, results of operations, or cash flows.

In connection with APS's status as a PRP for OU3, since 2013 APS and at least two dozen other parties have been defendants in various CERCLA lawsuits stemming from allegations that contamination from OU3 and elsewhere has impacted groundwater wells operated by the Roosevelt Irrigation District. At this time, only one active lawsuit remains pending in the U.S. District Court for Arizona, which concerns $8.3 million in remediation legal expenses. APS is unable to predict the outcome of any further litigation related to this claim or APS's share of liability related to that claim; however, APS does not expect the outcome to have a material impact on its financial position, results of operations, or cash flows.

On February 28, 2022, EPA provided APS with a request for information under CERCLA related to the Ocotillo site located in Tempe, Arizona. In particular, EPA seeks information from APS regarding APS's use, storage, and disposal of substances containing PFAS at the Ocotillo site in order to aid EPA's investigation into actual or threatened releases of PFAS into groundwater within the South Indian Bend Wash Superfund site. The South Indian Bend Wash Superfund site includes the Ocotillo site. APS filed its response to this information request on April 29, 2022. On January 17, 2023, EPA contacted APS to inform APS that it would be commencing on-site investigations within the South Indian Bend Wash site, including Ocotillo, and performing a remedial investigation and feasibility study related to potential PFAS impacts to groundwater over the next two to three years. APS estimates that its costs to oversee and participate in the remedial investigation work will be approximately $1.7 million. At the present time, we are unable to predict the outcome of this matter, and any further expenditures related to necessary remediation, if any, or further investigations cannot be reasonably estimated.

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 GHG, water quality, wastewater discharges, solid waste, hazardous waste, and 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 could involve material compliance costs to APS.

Coal Combustion Waste

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

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

- Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to either authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. ADEQ has taken steps to develop a CCR permitting program and proposed state regulations governing CCR permitting in the summer of 2024. On April 1, 2025, the Arizona Governor’s Regulatory Review Council approved ADEQ’s proposed rulemaking governing CCR permitting. ADEQ will submit an approval package to EPA, which will have to approve the entire state program before it is operational. It remains unclear when EPA would approve that permitting program pursuant to the Water Infrastructure

Improvements for the Nation Act. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits, which would impact facilities like Four Corners located on the Navajo Nation. The proposal remains pending.

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

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

On April 25, 2024, EPA took final action on a proposal to expand the scope of federal CCR regulations to address the impacts from historical CCR disposal activities that would have ceased prior to 2015. This new class of CCRMUs, which contain at least 1,000 tons of CCR, broadly encompasses any location at an operating coal-fired power plant where CCRs would have been placed on land. This would include not only historically closed landfills and surface impoundments but also prior applications of CCR beneficial use (with exceptions for historical roadbed and embankment applications). Existing CCR regulatory requirements for groundwater monitoring, corrective action, closure, post-closure care, and other requirements will be imposed on such CCRMUs. Under EPA's legacy 2024 CCRMU rule, initial CCRMU site surveys were originally due to be completed by February 2026 and final site investigation reports by February 2027.

On February 10, 2026, EPA published a final rule extending multiple compliance deadlines applicable to CCRMUs established under the prior rule. The final rule extends the deadline for completing Parts One and Two of Facility Evaluation Reports by one year to February 2027 and February 2028, respectively. EPA also extended associated compliance deadlines for groundwater monitoring and certain closure requirements. Subsequently, on April 9, 2026, EPA proposed a new regulation that contemplates a range of revisions to the 2024 legacy CCRMU rule, including full elimination of the 2024 standards among other alterations. EPA also proposes to expand the categories of activities that meet the definition of "beneficial use" of CCR, which is exempt from most federal CCR regulatory restrictions. In addition, EPA is proposing to authorize certain risk-based compliance alternatives for facilities subject to state or federal CCR permitting, which would allow adjustments to default standards for groundwater monitoring, groundwater protection standards, closure and post-closure care requirements, and additional measures concerning beneficial use.

APS is still in the process of evaluating the impacts of these CCRMU regulations on its business and cannot predict the outcome of any future rulemaking or other regulatory proceedings aimed at changing the current EPA CCRMU rules. Based on the information available to APS at this time, APS cannot reasonably estimate the cost of the entire CCRMU asset retirement obligation. Depending on the outcome of the pending legacy 2024 CCRMU rule amendments and APS's evaluations, the costs associated with APS's management of CCR could materially increase, which could affect our financial condition, results of operations, or cash flows.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

On May 28, 2026, EPA published notice reopening the comment period on its proposed rule to establish a federal permit program for the disposal of CCR ("2020 Proposed Federal CCR Permit Program Rule"). Under this proposal, EPA would directly issue permits for CCR units located in Indian Country and in states that do not have EPA-approved CCR permitting programs. EPA is soliciting comments on the estimated time needed to compile materials for site specific issues deferred to permitting; whether a six-month deadline after publication of the final permitting rule in the Federal Register is sufficient for the first tier of permit applications; and how best to implement electronic permitting for both EPA-issued CCR permits and states that are implementing the CCR permitting program in lieu of EPA.

APS currently disposes of CCR in ash ponds and dry storage areas at Four Corners. The Navajo Plant disposed of CCR only in a dry landfill storage area. Cholla disposed of CCR in ash ponds and dry storage areas prior to ceasing coal-fired operations. Additionally, the CCR rule requires ongoing, phased groundwater monitoring. As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must have ceased operating and initiated closure as of April 11, 2021 (except for those disposal units at Cholla that had been subject to alternative closure, which initiated closure work on June 30, 2025). APS completed the assessments of corrective measures on June 14, 2019; however, additional investigations and engineering analyses that will support the remedy selection are still underway. In addition, APS has also solicited input from the public and hosted public hearings as part of this process. APS's estimates for its share of corrective action and monitoring costs at Four Corners and Cholla are captured within the AROs and removal costs within Regulatory Liabilities. As APS continues to implement the CCR rule's corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until we have fully completed the corrective action assessment and final remedy selection process, we cannot predict any ultimate impacts to APS; however, at this time APS does not believe that any potential changes to the cost estimate from the CCR rule's corrective action assessment process for Four Corners or Cholla would have a material impact on its financial condition, results of operations, or cash flows.

EPA Power Plant Carbon Regulations

EPA's regulation of carbon dioxide emissions from electric utility power plants has proceeded in fits and starts over most of the last decade. Starting on August 3, 2015, EPA finalized the Clean Power Plan, which was the agency's first effort at such regulation through system-wide generation dispatch shifting. Those regulations were subsequently repealed by EPA on June 19, 2019 and replaced by the Affordable Clean Energy regulations, which were a far narrower set of rules. While the U.S. Court of Appeals for the D.C. Circuit subsequently vacated the Affordable Clean Energy regulations on January 19, 2021, and ordered a remand for EPA to develop replacement regulations consistent with the original 2015 Clean Power Plan, the U.S. Supreme Court subsequently reversed that decision on June 30, 2022, holding that the Clean Power Plan exceeded EPA's authority under the Clean Air Act.

In the latest final regulations governing power plant carbon dioxide emissions, released April 25, 2024, EPA issued emission standards and guidelines for various subcategories of new and existing power plants. Unlike EPA's Clean Power Plan regulations from 2015, which took a broad, system-wide approach to regulating carbon emissions from electric utility fossil-fuel burning power plants, these new federal regulations are limited to measures that can be installed at individual power plants to limit planet-warming carbon-dioxide emissions.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Under current rules, carbon emission performance standards apply based on the annual capacity factors for new natural gas-fired combustion turbine power plants. The highest utilization combustion turbines must be retrofitted for CCS by 2032. Intermediate or low-load natural gas fired combustion turbines with 40% or less capacity factors do not require add-on pollution controls. Instead, natural gas-fired combustion turbines with capacity factors of up to 20% are effectively unregulated, while turbines with capacity factors over 20% and up to 40% are subject to carbon dioxide emission rate limitations.

For coal-fired power plants, instead of imposing regulations based on capacity and utilization, EPA finalized subcategories based on planned retirement dates. Facilities retiring before 2032 are effectively exempt from regulation; those that retire between 2032 and 2038 must co-fire with natural gas starting in 2030; and those that retire in 2039 or later must install CCS controls by 2032.

As of May 10, 2024, several states, electric utility companies, affiliated trade associations, and other entities filed petitions for review of these regulations in the D.C. Circuit Court of Appeals. APS is participating in that litigation as part of an ad hoc coalition of electric utility companies, independent power producers, and trade groups, called Electric Generators for a Sensible Transition. On February 5, 2025, EPA filed an unopposed motion requesting that the D.C. Circuit Court of Appeals hold the GHG regulations case in abeyance for 60 days and withhold issuing an opinion while the new leadership at EPA evaluates the rule and determines how it wishes to proceed. On February 19, 2025, the Court granted EPA's motion. EPA subsequently filed a second motion asking the Court to keep the GHG regulations case in abeyance for an indefinite period of time given EPA's anticipated reconsideration of the rules, with EPA providing status reports every 90 days. On April 25, 2025, the D.C. Circuit granted EPA's motion for an indefinite abeyance. We cannot predict the outcome of the litigation challenging EPA's current carbon emission standards for power plants.

If the current regulations were to remain in effect, they would likely lead to a material increase in APS's costs to build, operate, and maintain new, frequently operated gas-fired power plants. The regulatory deadlines in 2032 by which new, frequently operated gas-fired power plants must install CCS and achieve 90% capture efficiency may not be feasible. Future resource plans and procurement efforts implicating the development of such new generation remain pending and, as such, at this time APS is not able to quantify the financial impact associated with EPA's existing GHG regulations for power plants.

On June 11, 2025, EPA put forth a proposed rule with two scenarios for repealing the GHG regulations finalized in 2024. EPA's primary proposal entails a full repeal of the GHG regulations based on a finding that GHG emissions from fossil fuel-fired power plants do not present a "significant contribution" to dangerous air pollution, thereby eliminating the 2024 GHG power plant regulations in their entirety.

Under EPA's alternative proposal, only certain portions of the 2024 GHG regulations would be repealed based on a finding that they are unlawful, including the emission guidelines for existing fossil fuel-fired steam generating units (coal-fired power plants), the CCS-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base-load stationary combustion turbines (i.e., those operating at greater than 40% annual capacity factors). This targeted approach would eliminate the CCS and natural gas co-firing technology-based pollution limits that would apply to both existing coal-fired power plants and new gas-fired combustion turbine power plants. However, efficiency-based standards for new combustion turbines would remain in place under this alternative proposal.

EPA's proposed rule to repeal the 2024 GHG regulations was published in the Federal Register on June 17, 2025. Comments were due by August 7, 2025. We cannot predict the outcome of future rulemaking or other regulatory proceedings aimed at changing or eliminating the current EPA emission standards for power plants.

On February 18, 2026, EPA's repeal of the 2009 "Endangerment Finding" was finalized and published in the Federal Register. This action is expected to provide legal and regulatory support for EPA's pending proposals seeking to eliminate or significantly limit the scope of the current EPA carbon emission standards and guidelines for new and existing power plants. The repeal of the "Endangerment Finding" is subject to judicial review, with lawsuits being filed on February 18, 2026 in the D.C. Circuit Court of Appeals seeking to challenge the repeal. We cannot predict the outcome of the litigation.

Effluent Limitation Guidelines

EPA published ELG on October 13, 2020, and, based off those guidelines, APS completed a NPDES permit modification for Four Corners on December 1, 2023. The ELG standards finalized in October 2020 relaxed the "zero discharge" standard for bottom ash transport waters EPA finalized in September 2015. However, on April 25, 2024, EPA finalized new ELG regulations that once again require "zero discharge" standards for flows of bottom ash transport water at power plants like Four Corners ("2024 ELG Rule"). For power plants that permanently cease operations by December 31, 2034, such facilities can continue to comply with the 2020 ELG standards. APS is currently evaluating its compliance options for Four Corners based on the ELG regulations finalized in April 2024 and is assessing what impacts the new standards will have on our financial condition, results of operations, or cash flows.

On December 31, 2025, EPA published a final rule extending by five years the compliance deadlines for achieving the 2024 zero-discharge standards for bottom ash transport wastewater from year-end 2029 to year-end 2034, among other changes to the 2024 rulemaking. EPA is also collecting additional information on zero-discharge technologies, including cost and performance data, to inform future potential rulemakings to modify or relax the current zero-discharge ELG standards. We cannot predict the outcome of any future rulemaking or other regulatory proceedings aimed at modifying the current ELG standards.

On May 18, 2026, EPA published a proposed rule to revise the 2024 ELG Rule limits and standards for unmanaged combustion residual leachate ("CRL"), or water leaking from landfills or surface impoundments that contains coal combustion residuals. The proposal would introduce flexible, site-specific approaches for managing unmanaged CRL at steam electric power plants, such as Four Corners, rather than applying a strict, national zero-discharge framework across the board as implemented under the 2024 ELG Rule. On May 22, 2026, a coalition of Environmental NGOs, including Sierra Club, Center for Biological Diversity, Natural Resources Defense Council, and Public Employees for Environmental Responsibility, filed a petition for review in the Ninth Circuit Court of Appeals challenging the EPA's final action. APS will continue to monitor this proceeding. At this time, APS is unable to predict the outcome of this litigation.

EPA Good Neighbor Proposal for Arizona

On March 15, 2023, EPA issued its final Good Neighbor Plan for 23 states in order to ensure that the cross-state transport of ozone forming emissions does not interfere with downwind state compliance with the NAAQS. Thermal power plant emission limitations are a key aspect of these regulations, which involve emission allowance trading for NOx emissions. While Arizona was not among the 23 states subject to EPA's March 2023 final action, EPA announced on January 23, 2024, that it was proposing to add Arizona and New Mexico (along with two other additional states) to EPA's NOx emission allowance trading program finalized last year. That proposal involves adding these states to the Good Neighbor Plan and disapproving the corresponding provisions of each state's State Implementation Plan. Because APS operates thermal power plants within Arizona and those portions of the Navajo Nation within New Mexico, APS's power plants would be subject to EPA's Good Neighbor Plan upon finalization of this proposal. EPA's final Good Neighbor Plan is subject to ongoing judicial review in the D.C. Circuit Court of Appeals. On June 27, 2024, the U.S. Supreme Court granted a motion to stay the effectiveness of EPA's final Good Neighbor Plan pending the resolution of the litigation. As such, APS will not be impacted by the Good Neighbor Plan until the outcome of this litigation is finalized. In addition, on December 19, 2024, EPA announced that it was withdrawing its proposal to add Arizona (along with other western states) to the federal Good Neighbor Plan. On March 12, 2025, EPA announced its intention to reconsider the Good Neighbor Plan and on January 30, 2026, EPA published a proposed rule in the Federal Register that would approve Arizona's and New Mexico's State Implementation Plans concerning the cross-state transport of ozone forming emissions. Such approval, if finalized as proposed, would remove APS's operations in Arizona and New Mexico from the scope of future efforts to regulate such emissions. APS cannot predict the outcome of this pending regulatory action nor when EPA may take final action on this proposal. If finalized as proposed, this action would then be subject to judicial review and APS cannot predict the outcome of such litigation, if any arises. In addition, APS cannot predict the outcome of any future EPA efforts to add Arizona or New Mexico to a future federal program addressing the cross-state transport of ozone-forming emissions. Should a federal program like the Good Neighbor Plan ultimately be imposed on APS and its operations in Arizona and New Mexico, it would have material impact on both the costs to operate current APS power plants and APS's ability to develop new thermal generation to serve load. At this time, APS cannot predict the impact on the Company's financial condition, results of operations, or cash flows.

Revised Mercury and Air Toxics Standard ("MATS") Proposal

On February 20, 2026, EPA issued a final rule repealing the 2024 revisions to MATS regulations governing emissions of toxic air pollution from existing coal-fired power plants. The repeal of the 2024 amendment means that MATS regulations revert to the pre-existing framework for MATS emission limits established in 2012. As a result, the 2024 revisions that would have increased the stringency of filterable particulate matter limits used to demonstrate compliance with MATS and required the use of continuous emissions monitoring systems to ensure compliance (as opposed to periodic performance testing) will not take effect for existing coal-fired power plants, such as Four Corners.

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 APS's fossil-fuel powered 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support commodity contract collateral obligations and other transactions. As of June 30, 2026, standby letters of credit totaled approximately $30.4 million and will expire through 2027, and surety bonds totaled approximately $26.1 million and will expire through 2028. 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 remaining Palo Verde sale leaseback transaction with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

Pinnacle West has issued parental guarantees and has provided indemnification under certain surety bonds for APS which were not material as of June 30, 2026. In connection with the sale of Pinnacle West's wholly-owned subsidiary, 4C Acquisition, LLC's 7% interest in Units 4 and 5 of Four Corners to NTEC, Pinnacle West guaranteed certain obligations that NTEC has to the other owners of Four Corners. Pinnacle West has not needed to perform under this guarantee. A maximum obligation is not explicitly stated in the guarantee and, therefore, the overall maximum amount of the obligation under such guarantee cannot be reasonably estimated; however, we consider the fair value of this guarantee, including expected credit losses, to be immaterial.

In connection with PNW Power's investments in minority ownership positions in the Clear Creek wind farm in Missouri and Nobles 2 wind farm in Minnesota, Pinnacle West has guaranteed the obligations of PNW Power to make PTC funding payments to borrowers of the projects (the "PTC Guarantees"). The amounts guaranteed by Pinnacle West are reduced as payments are made under the respective guarantee agreements. As of June 30, 2026, there is approximately $24.6 million remaining relating to these PTC Guarantees that are expected to terminate by 2031.

Pinnacle West issued various performance guarantees in connection with a joint venture project, the Kūpono Solar Project, by BCE, a former subsidiary of Pinnacle West. BCE was sold to Ameresco in 2024 (the "BCE Sale"). Subsequent to the BCE Sale, Pinnacle West continues to maintain these Kūpono Solar Project investment financing guarantees and is exposed to losses relating to these guarantees upon the occurrence of certain events that we consider to be remote. Under the Kūpono Solar Project sale-leaseback financing, Pinnacle West has committed to certain performance guarantees that may apply upon the occurrence of specified events, such as uninsured loss events. Ameresco, the owner of the Kūpono Solar Project, has agreed to make efforts to refinance the project and eliminate these guarantees prior to 2030. Pinnacle West has not needed to perform under these guarantees. Maximum obligations are not explicitly stated in the guarantees and cannot be reasonably estimated. Ameresco is obligated to reimburse Pinnacle West for any payments made by Pinnacle West under such guarantees. We consider the fair value of these guarantees, including expected credit losses, to be immaterial.

12. Other Income and Other Expense

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
Other income:				
Interest income	$ 1,767	$ 4,260	$ 4,648	$ 10,256
Investment gain — net (a)	6,801	6,504	8,593	17,488
Miscellaneous	4,528	1,340	4,836	1,821
Total other income	$ 13,096	$ 12,104	$ 18,077	$ 29,565
Other expense:				
Non-operating costs	$ (5,752)	$ (3,245)	$ (8,214)	$ (5,474)
Miscellaneous	(818)	(1,014)	(1,096)	(1,355)
Total other expense	$ (6,570)	$ (4,259)	$ (9,310)	$ (6,829)

(a) Primarily relates to El Dorado investment activities. See Note 18.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
Other income:				
Interest income	$ 1,757	$ 3,674	$ 4,277	$ 9,281
Miscellaneous	18	—	143	115
Total other income	$ 1,775	$ 3,674	$ 4,420	$ 9,396
Other expense:				
Non-operating costs	$ (4,951)	$ (2,876)	$ (7,341)	$ (4,868)
Miscellaneous	(815)	(1,014)	(1,093)	(1,355)
Total other expense	$ (5,766)	$ (3,890)	$ (8,434)	$ (6,223)

13. Common Stock Equity and Earnings Per Share

At-the-Market Program

On November 8, 2024, Pinnacle West opened its ATM Program, pursuant to which Pinnacle West may sell, from time to time, up to $900 million of its common stock through an at-the-market equity distribution program, which includes the ability to enter into forward sale agreements.

As of June 30, 2026, Pinnacle West had thirteen outstanding forward sale agreements under its ATM Program (collectively, the "ATM Forward Sale Agreements"). These agreements relate to approximately $816 million, on a gross basis, of common stock and may be settled at Pinnacle West's discretion by issuing shares at the applicable forward sales price or, alternatively, by delivering cash in lieu of shares. On June 26, 2026, Pinnacle West entered into a fourteenth forward sale agreement, with an effective date of July 6, 2026, relating to a total of $84 million, on a gross basis, of common stock, with a maturity date of July 3, 2028. Following entry into this agreement, the $900 million of sales of common stock contemplated by the ATM Program have been substantially completed.

The following table presents information about the outstanding ATM Forward Sale Agreements as of June 30, 2026 based on their contractual terms at the effective date of the agreement, including the applicable forward sale prices and related aggregate contractual values, which may differ from the gross amount of common stock referenced above (dollars in thousands, except price per share):

ATM Forward Sale Agreements	Maturity (a)	Number of Shares	Forward Sales Price Per Share (b)	Aggregate Value
November 2024	December 2026	552,833	$ 89.73	$ 49,606
March 2025	December 2026	544,959	$ 90.83	$ 49,499
August 2025	February 2027	543,001	$ 91.21	$ 49,527
September 2025	February 2027	558,622	$ 88.69	$ 49,544
January 2026	July 2027	119,553	$ 89.88	$ 10,745
March 2026	September 2027	646,674	$ 99.52	$ 64,357
March 2026	September 2027	490,537	$ 100.94	$ 49,515
March 2026	September 2027	488,813	$ 101.28	$ 49,507
March 2026	September 2027	916,930	$ 98.12	$ 89,969
April 2026	September 2027	1,000,000	$ 99.00	$ 99,000
May 2026	November 2027	699,100	$ 99.16	$ 69,323
June 2026	December 2027	879,813	$ 101.35	$ 89,169
June 2026	June 2028	865,297	$ 103.00	$ 89,126
		8,306,132	$ 97.38 (c)	$ 808,887 (d)

(a) Maturity date may be extended. Maturity date set forth in the table is as extended, if applicable.
(b) Subject to certain adjustments.
(c) Total weighted-average share price.
(d) Does not include one forward sale agreement, whose effective date was July 6, 2026, relating to a total of $84 million, on a gross basis, of common stock, with a maturity date of July 3, 2028.

Non-ATM February 2024 Forward Sale Agreements

In addition to the ATM Forward Sale Agreements, Pinnacle West also has Forward Sale Agreements that were entered into on February 28, 2024 (the "February 2024 Forward Sale Agreements"). These agreements may be settled at Pinnacle West's discretion by issuing shares of Pinnacle West common stock and receiving cash, if any, at the then-applicable forward sales price. The terms of the February 2024 Forward Sale Agreements also allow Pinnacle West, at its option, to settle the agreements with the counterparties by delivering cash, in lieu of shares. The February 2024 Forward Sale Agreements were partially settled in December 2024, September 2025, and December 2025. In August 2025, APS amended the February 2024 Forward Sale Agreements with Wells Fargo Bank, National Association, to extend the maturity date of those forward confirmations to December 31, 2026.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table presents information about the outstanding February 2024 Forward Sale Agreements as of June 30, 2026 (dollars in thousands, except price per share):

February 2024 Forward Sale Agreements	Number of Shares	Forward Sales Price Per Share	Aggregate Value
Initial Price	11,240,601	$ 64.51 (a)	$ 725,131
Settlements			
December 23, 2024	5,377,115 (b)	$ 64.17	$ 345,049 (c)
September 4, 2025	243,186 (b)	$ 63.12	$ 15,350 (c)
December 18, 2025	1,193,950 (b)	$ 62.82	$ 75,004 (c)

(a) Subject to certain adjustments.
(b) Physical delivery.
(c) Proceeds recorded in common equity on the Condensed Consolidated Balance Sheets.

Convertible Notes

In June 2024, Pinnacle West issued $525 million of 4.75% Convertible Senior Notes due 2027, which are senior unsecured obligations of Pinnacle West and will mature on June 15, 2027. Interest is payable semiannually in arrears on June 15 and December 15 of each year, beginning on December 15, 2024.

Prior to March 15, 2027, the holders of the Convertible Notes may elect at their option to convert all or any portion of their Convertible Notes under the following limited circumstances:

- during any calendar quarter (and only during such calendar quarter), if the sale price of Pinnacle West common stock for at least 20 trading days (whether or not consecutive) during a period of 30 consecutive trading days ending on, and including, the last trading day of the immediately preceding calendar quarter, is greater than or equal to 130% of the conversion price on each applicable trading day;

- during the five business day period after any 10 consecutive trading day period (“Measurement Period”) in which the trading price per $1,000 principal amount of Convertible Notes for each trading day of the Measurement Period was less than 98% of the product of the last reported sale price of Pinnacle West common stock and the conversion rate on such trading day; or

- upon the occurrence of certain corporate events, as defined in the Convertible Notes’ indenture.

On or after March 15, 2027, until the maturity date, the holders of the Convertible Notes may elect at their option to convert all or any portion of their notes. Upon conversion, Pinnacle West will pay cash up to the aggregate principal amount of the Convertible Notes converted and at Pinnacle West’s sole discretion, pay or deliver cash, shares of Pinnacle West common stock or a combination of both, in respect to the remainder, if any, of Pinnacle West’s conversion obligation in excess of the aggregate principal amount of the Convertible Notes being converted. The initial conversion rate, which is subject to certain adjustments as set forth in the indenture, is 10.8338 shares of common stock per $1,000 principal amount of Convertible Notes, which is equivalent to an initial conversion price of approximately $92.30 per share. The conversion rate is not subject to adjustment for any accrued and unpaid interest.

If Pinnacle West undergoes a fundamental change, as defined in the Convertible Notes' indenture, then, subject to certain conditions, holders of the Convertible Notes may require Pinnacle West to repurchase for cash all or any portion of its Convertible Notes at a repurchase price equal to 100% of the principal amount of the Convertible Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the fundamental change repurchase date.

As of June 30, 2026, the conditions allowing holders to convert their Convertible Notes were not met, and as a result, the Convertible Notes were classified as current maturities of long-term debt on Pinnacle West's Condensed Consolidated Balance Sheets with a carrying amount of $525 million, net of approximately $2 million in unamortized debt issuance costs. The estimated fair value of the Convertible Notes as of June 30, 2026 was approximately $629 million (Level 2 within the fair value hierarchy).

As of June 30, 2026, based on Pinnacle West's average stock price and the relevant terms of the Convertible Notes, there were shares of Pinnacles West's common stock included in diluted EPS relating to the potential conversion of the Convertible Notes, but no shares included in basic EPS.

Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
Net income attributable to common shareholders	$ 178,574	$ 192,564	$ 211,494	$ 187,920
Weighted average common shares outstanding — basic	121,306	119,517	121,333	119,555
Net effect of dilutive securities:				
Contingently issuable performance shares and restricted stock units	469	548	457	523
Dilutive shares related to equity forward sale agreements (a)	2,156	1,800	1,939	1,735
Dilutive shares related to convertible debt instruments (b)	563	—	407	—
Total contingently issuable shares	3,188	2,348	2,803	2,258
Weighted average common shares outstanding — diluted	124,494	121,865	124,136	121,813
Earnings per weighted-average common share outstanding				
Net income attributable to common shareholders — basic	$ 1.47	$ 1.61	$ 1.74	$ 1.57
Net income attributable to common shareholders — diluted	$ 1.43	$ 1.58	$ 1.70	$ 1.54

(a) For the three and six months ended June 30, 2026 and 2025, there were no potentially dilutive shares related to equity forward sale agreements excluded from the calculation of diluted weighted-average common shares.

(b) No shares related to the Convertible Notes were excluded from diluted weighted-average common shares for the three and six months ended June 30, 2026. For the three and six months ended June 30, 2025, potentially issuable shares of 51,380 and 244,134, respectively, were excluded from the diluted weighted-average common shares calculation as their inclusion would have been antidilutive.

Pinnacle West's forward sale agreements are classified as equity transactions and are not recorded on the Pinnacle West Condensed Consolidated Balance Sheets until shares are settled. Delivery of shares to settle equity forward agreements will result in dilution to basic EPS upon settlement. Prior to settlement, the potentially issuable shares are reflected in our diluted EPS calculations using the treasury stock method. Under this method, the number of shares, if any, that would be issued upon settlement is reduced by the number of shares that could be purchased by Pinnacle West in the market with the proceeds received from issuance (based on the average market price during the reporting period). Share dilution occurs when the average market price of our stock during the reporting period is higher than the adjusted forward sale price as of the end of the reporting period.

14. Fair Value Measurements

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

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

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

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

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

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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Recurring Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, and investments held in the nuclear decommissioning trusts and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefit plans. See Note 7 in the 2025 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 — Energy Derivative Instruments

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

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

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

Investments Held in Nuclear Decommissioning Trusts and Other Special Use Funds

The nuclear decommissioning trusts and other special use funds invest in fixed income and equity securities. Other special use funds include the coal reclamation escrow account, the active union employee medical account, and the Captive. See Note 15 for additional discussion about our investment accounts.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

Fixed Income Securities

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

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

Equity Securities

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

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

Fair Value Tables

The following table presents the fair value as of June 30, 2026 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
ASSETS						
Cash equivalents	$ 103	$ —	$ —	$ —		$ 103
Risk management activities — derivative instruments:						
Commodity contracts	—	1,744	268	(2,007)	(a)	5
Nuclear decommissioning trusts:						
Equity securities	14,214	—	—	8,971	(b)	23,185
U.S. commingled equity funds	—	—	—	549,368	(c)	549,368
U.S. Treasury debt	394,337	—	—	—		394,337
Corporate debt	—	250,143	—	—		250,143
Mortgage-backed securities	—	213,368	—	—		213,368
Municipal bonds	—	18,146	—	—		18,146
Other fixed income	—	19,411	—	—		19,411
Subtotal nuclear decommissioning trusts	408,551	501,068	—	558,339		1,467,958
Other special use funds:						
Equity securities	54,944	—	—	6,968	(b)	61,912
U.S. Treasury debt	369,957	—	—	—		369,957
Subtotal other special use funds (d)	424,901	—	—	6,968		431,869
Total assets	$ 833,555	$ 502,812	$ 268	$ 563,300		$ 1,899,935
LIABILITIES						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (47,713)	$ (33,130)	$ (284)	(a)	$ (81,127)

(a) Represents counterparty netting, margin, and collateral. See Note 10.
(b) Represents net pending securities sales and purchases.
(c) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.
(d) All amounts relate to APS, with the exception of $42.2 million related to Pinnacle West's Captive investments that are classified within Level 1 equity securities and $4.0 million classified as Other equity securities. See Note 9.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value as of December 31, 2025 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Other		Total
ASSETS						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ 19,347	$ —	$ (10,960)	(a)	$ 8,387
Nuclear decommissioning trusts:						
Equity securities	18,970	—	—	(3,799)	(b)	15,171
U.S. commingled equity funds	—	—	—	500,592	(c)	500,592
U.S. Treasury debt	364,943	—	—	—		364,943
Corporate debt	—	242,176	—	—		242,176
Mortgage-backed securities	—	230,695	—	—		230,695
Municipal bonds	—	37,572	—	—		37,572
Other fixed income	—	23,017	—	—		23,017
Subtotal nuclear decommissioning trusts	383,913	533,460	—	496,793		1,414,166
Other special use funds:						
Equity securities	62,573	—	—	3,199	(b)	65,772
U.S. Treasury debt	369,055	—	—	—		369,055
Subtotal other special use funds (d)	431,628	—	—	3,199		434,827
Total assets	$ 815,541	$ 552,807	$ —	$ 489,032		$ 1,857,380
LIABILITIES						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (21,325)	$ (23,710)	$ 8,399	(a)	$ (36,636)

(a) Represents counterparty netting, margin, and collateral. See Note 10.
(b) Represents net pending securities sales and purchases.
(c) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.
(d) All amounts relate to APS, with the exception of $40.3 million related to Pinnacle West's Captive investments that are classified within Level 1 equity securities. See Note 9.

Fair Value Measurements Classified as Level 3

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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

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

The following tables provide information regarding our significant unobservable inputs used to value our risk management derivative Level 3 instruments as of June 30, 2026 and December 31, 2025 (dollars in thousands):

Commodity Contracts	June 30, 2026 Fair Value Assets	June 30, 2026 Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Range	Weighted-Average (b)
Electricity:						
Electricity Forward Contracts (a)	$ —	$ 23,980	Discounted cash flows	Electricity forward price (per MWh)	$42.50 - $91.17	$62.82
Natural Gas Forward Contracts (a)	268	9,150	Discounted cash flows	Natural gas forward price (per Million British Thermal Units (“MMBtu”))	$(0.59) - $0.26	$(0.02)
Total	$ 268	$ 33,130				

(a) Includes swaps and physical and financial contracts.
(b) Unobservable inputs were weighted by the relative fair value of the instrument.

Commodity Contracts	December 31, 2025 Fair Value Assets	December 31, 2025 Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Range	Weighted-Average (b)
Electricity Forward Contracts (a)	$ —	$ 21,913	Discounted cash flows	Electricity forward price (per MWh)	$ 41.51 - $149.37	$80.20
Natural Gas Forward Contracts (a)	—	1,797	Discounted cash flows	Natural gas forward price (per MMBtu)	$(0.07) - $0.36	$0.04
Total	$ —	$ 23,710				

(a) Includes swaps and physical and financial contracts.
(b) Unobservable inputs were weighted by the relative fair value of the instrument.

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 (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
Commodity Contracts	2026	2025	2026	2025
Balance at beginning of period	$ (33,456)	$ (22,840)	$ (23,710)	$ (15,039)
Total net losses realized/unrealized:				
Deferred as a regulatory asset or liability	(2,285)	2,194	(16,862)	(3,629)
Settlements	885	1,883	5,716	(404)
Transfers into Level 3 from Level 2	—	(329)	—	(388)
Transfers from Level 3 into Level 2	1,994	300	1,994	668
Balance at end of period	$ (32,862)	$ (18,792)	$ (32,862)	$ (18,792)
Net unrealized gains/losses included in earnings related to instruments still held at end of period	$ —	$ —	$ —	$ —

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 values of our short-term borrowings approximate fair value and are classified within Level 2 of the fair value hierarchy. See Note 6 for our long-term debt fair values.

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

We have investments in debt and equity securities held in nuclear decommissioning trusts and other special use funds. 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 14 for a discussion of how fair value is determined and the classification of the investments within the fair value hierarchy. The investments in each trust or account are restricted for use and are intended to fund specified costs and activities as further described for each fund below.

Nuclear Decommissioning Trusts

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

Coal Reclamation Escrow Account

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

Active Union Employee Medical Account

APS has investments restricted for paying active union employee medical costs. These investments may be used to pay active union employee medical costs incurred in the current and future periods. In April 2026, APS was reimbursed $13 million for active union employee medical claims from the active union employee medical account. The account is invested primarily in fixed income securities. In accordance with the ratemaking treatment, APS has deferred the unrealized gains and losses (including credit losses) in other regulatory assets. Activities relating to active union employee medical account investments are included within the other special use funds in the table below.

Captive Insurance Cell

Pinnacle West has investments held by the Captive that may be used to pay insurance losses in the event of certain insured loss events. The Captive may hold investment assets in cash, cash equivalents, and equity and fixed income instruments. These investments are restricted for insured loss events.

Pinnacle West consolidated investment holdings reflected in the tables below primarily relate to APS, with the exception of the Captive's investments included within other special use funds.

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

	June 30, 2026				
	Fair Value				
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total	Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 563,582	$ 54,944	$ 618,526	$ 478,401 (d)	$ (6)
Available for sale-fixed income securities	895,405	369,957	1,265,362 (a)	9,369	(16,048)
Other	8,971	6,968	15,939 (b)	481	—
Total	$ 1,467,958	$ 431,869	$ 1,899,827 (c)	$ 488,251	$ (16,054)

(a) As of June 30, 2026, the amortized cost basis of these available-for-sale investments is $1,272 million.
(b) Primarily represents net pending securities sales and purchases.
(c) All amounts pertain to APS, with the exception of $42.2 million of other special use fund investments in equity securities and $4.0 million of other, relating to investments held by the Captive.
(d) All amounts pertain to APS, with the exception of $3.7 million of unrealized gains relating to investments held by the Captive.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

	December 31, 2025				
	Fair Value				
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total	Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 519,562	$ 62,573	$ 582,135	$ 433,044 (d)	$ (1)
Available for sale-fixed income securities	898,403	369,055	1,267,458 (a)	18,765	(14,993)
Other	(3,799)	3,199	(600) (b)	—	—
Total	$ 1,414,166	$ 434,827	$ 1,848,993 (c)	$ 451,809	$ (14,994)

(a) As of December 31, 2025, the amortized cost basis of these available-for-sale investments is $1,265 million.
(b) Represents net pending securities sales and purchases.
(c) All amounts pertain to APS, with the exception of $40.3 million of other special use fund investments in equity securities relating to investments held by the Captive.
(d) All amounts pertain to APS, with the exception of $3.2 million of unrealized gains relating to investments held by the Captive.

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

	Three Months Ended June 30,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2026			
Realized gains	$ 2,505	$ 154	$ 2,659
Realized losses	$ (4,656)	$ —	$ (4,656)
Proceeds from the sale of securities (a)	$ 403,032	$ 82,361 (b)	$ 485,393
2025			
Realized gains	$ 1,702	$ —	$ 1,702
Realized losses	$ (2,611)	$ —	$ (2,611)
Proceeds from the sale of securities (a)	$ 342,313	$ 91,517 (c)	$ 433,830

(a) Proceeds are reinvested in the nuclear decommissioning trusts and other special use funds, excluding investment fees and amounts reimbursed to the Company for active union employee medical claims from the active union employee medical account.
(b) All amounts pertain to APS, with the exception of $5.8 million of other special use fund proceeds from the sale of securities relating to investments held by the Captive.
(c) All amounts pertain to APS, with the exception of $25.2 million of other special use fund proceeds from the sale of securities relating to the Captive.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

	Six Months Ended June 30,			
	Nuclear Decommissioning Trusts	Other Special Use Funds		Total
2026				
Realized gains	$ 7,225	$ 170		$ 7,395
Realized losses	$ (7,453)	$ —		$ (7,453)
Proceeds from the sale of securities (a)	$ 850,915	$ 146,712	(b)	$ 997,627
2025				
Realized gains	$ 3,360	$ —		$ 3,360
Realized losses	$ (5,372)	$ —		$ (5,372)
Proceeds from the sale of securities (a)	$ 758,914	$ 160,730	(c)	$ 919,644

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

(b) All amounts pertain to APS, with the exception of $5.8 million of other special use fund proceeds from the sale of securities relating to investments held by the Captive.

(c) All amounts pertain to APS, with the exception of $50.5 million of other special use fund proceeds from the sale of securities relating to investments held by the Captive.

Fixed Income Securities Contractual Maturities

The fair value of fixed income securities summarized by contractual maturities as of June 30, 2026 is as follows (dollars in thousands):

	Nuclear Decommissioning Trusts	Coal Reclamation Escrow Account	Active Union Employee Medical Account	Total
Less than one year	$ 28,346	$ 101,521	$ 39,940	$ 169,807
1 year – 5 years	282,988	56,420	155,655	495,063
5 years – 10 years	212,249	—	16,421	228,670
Greater than 10 years	371,822	—	—	371,822
Total	$ 895,405	$ 157,941	$ 212,016	$ 1,265,362

16. Changes in Accumulated Other Comprehensive Loss

The following tables show the changes in Pinnacle West’s consolidated accumulated other comprehensive income (loss), including reclassification adjustments, net of tax, by component (dollars in thousands):

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

	Pension and Other Postretirement Benefits		Derivative Instruments	Total
Three Months Ended June 30				
Balance March 31, 2026	$ (32,478)		$ 529	$ (31,949)
Other comprehensive income before reclassifications	404		18	422
Amounts reclassified from accumulated other comprehensive loss	493	(a)	—	493
Balance June 30, 2026	$ (31,581)		$ 547	$ (31,034)
Balance March 31, 2025	$ (31,163)		$ 1,069	$ (30,094)
Other comprehensive loss before reclassifications	(503)		(294)	(797)
Amounts reclassified from accumulated other comprehensive loss	450	(a)	—	450
Balance June 30, 2025	$ (31,216)		$ 775	$ (30,441)

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 8.

	Pension and Other Postretirement Benefits		Derivative Instruments	Total
Six Months Ended June 30				
Balance December 31, 2025	$ (32,980)		$ 572	$ (32,408)
Other comprehensive income/(loss) before reclassifications	404		(25)	379
Amounts reclassified from accumulated other comprehensive loss	995	(a)	—	995
Balance June 30, 2026	$ (31,581)		$ 547	$ (31,034)
Balance December 31, 2024	$ (31,661)		$ 719	$ (30,942)
Other comprehensive income/(loss) before reclassifications	(503)		56	(447)
Amounts reclassified from accumulated other comprehensive loss	948	(a)	—	948
Balance June 30, 2025	$ (31,216)		$ 775	$ (30,441)

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 8.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	Pension and Other Postretirement Benefits	
Three Months Ended June 30		
Balance March 31, 2026	$ (15,047)	
Other comprehensive income before reclassifications	454	
Amounts reclassified from accumulated other comprehensive loss	406	(a)
Balance June 30, 2026	$ (14,187)	
Balance March 31, 2025	$ (13,710)	
Other comprehensive loss before reclassifications	(504)	
Amounts reclassified from accumulated other comprehensive loss	368	(a)
Balance June 30, 2025	$ (13,846)	

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 8.

	Pension and Other Postretirement Benefits	
Six Months Ended June 30		
Balance December 31, 2025	$ (15,457)	
Other comprehensive income before reclassifications	454	
Amounts reclassified from accumulated other comprehensive loss	816	(a)
Balance June 30, 2026	$ (14,187)	
Balance December 31, 2024	$ (14,116)	
Other comprehensive loss before reclassifications	(504)	
Amounts reclassified from accumulated other comprehensive loss	774	(a)
Balance June 30, 2025	$ (13,846)	

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 8.

17. Leases

We lease certain land, buildings, vehicles, equipment, and other property through operating rental agreements with varying terms, provisions, and expiration dates. APS also has certain power purchase or PPAs and energy storage agreements that qualify as lease arrangements. Our leases have remaining terms that expire in 2026 through 2073. Substantially all of our leasing activities relate to APS.

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. The lessor trust entities have been deemed VIEs for which APS is the primary beneficiary. As the primary beneficiary, APS consolidated these lessor trust entities. The impacts from these sale leaseback transactions are excluded from our lease disclosures as lease accounting is eliminated upon consolidation. In September 2025, two of the three leased interests were purchased by APS. As of June 30, 2026, one VIE lease arrangement remains in effect. See Note 9.

APS is party to PPAs that allow it the right to the generation capacity from certain natural-gas fueled generators during certain months of each year throughout the term of the arrangements. As APS only has rights to use the assets during certain periods of each year, the leases have non-consecutive periods of use. APS does not operate or maintain the leased assets. APS controls the dispatch of the leased assets during the months of use and is required to pay a fixed monthly capacity payment during these periods of use. For these types of leased assets, APS has elected to combine both the lease and non-lease payment components and accounts for the entire fixed payment as a lease obligation. In addition to the fixed monthly capacity payments, APS must also pay variable charges based on the actual production volume of the assets. The variable consideration is not included in the measurement of our lease obligation.

During the first quarter of 2026, APS modified two existing purchase power operating lease agreements. These agreements relate to natural-gas tolling purchase power agreements. Among other changes, the modifications extend the expiration date of the leases, change the periods of use, and modify the pricing. The modified lease agreements continue to qualify as operating lease agreements. These will now terminate in October 2038 and December 2046.

APS has executed various energy storage PPAs that allow APS the right to charge and discharge energy storage facilities. APS pays a fixed monthly capacity price for rights to use the lease assets. The agreements generally have 20-year lease terms and provide APS with the exclusive use of the energy storage assets through the lease term. APS does not operate or maintain the energy storage facilities and has no purchase options or residual value guarantees relating to these lease assets. For this class of energy storage lease assets, APS has elected to separate the lease and non-lease components. These leases are accounted for as operating leases, with lease terms that commenced between September 2023 and June 2026.

The following table provides information related to our lease costs (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
Operating Lease Cost - PPAs and Energy Storage PPA Lease Contracts	$ 118,743	$ 76,947	$ 173,133	$ 89,494
Operating Lease Cost - Land, Property, and Equipment	6,429	5,286	12,730	10,623
Total Operating Lease Cost	125,172	82,233	185,863	100,117
Variable Lease Cost (a)	47,069	32,838	72,382	54,208
Short-term Lease Cost	811	528	1,686	1,120
Total Lease Cost	$ 173,052	$ 115,599	$ 259,931	$ 155,445

(a) Primarily relates to PPA lease contracts.

Lease costs are primarily included as a component of operating expenses on our Condensed Consolidated Statements of Income. Lease costs relating to PPAs and energy storage PPA lease contracts are recorded in fuel and purchased power on the Condensed Consolidated Statements of Income and are subject to recovery under the PSA or RES. See Note 7. The tables above reflect the lease cost amounts before the effect of regulatory deferral under the PSA and RES. Variable lease costs are recognized in the period the costs are incurred, and primarily relate to renewable PPA lease contracts. Payments under most renewable PPA lease contracts are dependent upon environmental factors, and due to the inherent uncertainty associated with the reliability of the fuel source, the payments are considered variable and are excluded from the measurement of lease liabilities and right-of-use lease assets. Certain of our lease agreements have lease terms with non-consecutive periods of use. For these agreements, we recognize lease costs during the periods of use. Leases with initial terms of 12 months or less are considered short-term leases and are not recorded on the balance sheets.

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

	June 30, 2026		
Year	**PPAs and Energy Storage PPA Lease Contracts**	**Land, Property and Equipment Leases**	**Total**
2026 (remaining six months of 2026)	$ 277,635	$ 11,817	$ 289,452
2027	474,522	21,294	495,816
2028	514,782	18,602	533,384
2029	519,979	16,469	536,448
2030	525,281	12,247	537,528
2031	530,697	5,767	536,464
Thereafter	6,674,719	56,170	6,730,889
Total lease commitments	9,517,615	142,366	9,659,981
Less imputed interest	4,482,414	41,680	4,524,094
Total lease liabilities	$ 5,035,201	$ 100,686	$ 5,135,887

We recognize lease assets and liabilities upon lease commencement. As of June 30, 2026, we have various lease arrangements that have been executed, but have not yet commenced. We expect the total fixed consideration paid for these arrangements, which includes both lease and non-lease payments, will approximate $9.5 billion over the terms of the agreements. These arrangements primarily relate to energy storage PPA assets. We expect lease commencement dates ranging from July 2026 through June 2028, with lease terms expiring through June 2048.

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

	Six Months Ended June 30,	
	2026	**2025**
Cash paid for amounts included in the measurement of lease liabilities — operating cash flows	$ 148,672	$ 60,813
Right-of-use operating lease assets obtained in exchange for operating lease liabilities	$ 1,393,894 (a)	$ 2,071,145 (b)

	June 30, 2026	December 31, 2025
Weighted average remaining lease term	17 years	15 years
Weighted average discount rate (c)	8.24 %	5.48 %

(a) Primarily relates to two PPA operating lease agreements that were modified in 2026 along with three new energy storage operating lease agreements that commenced in 2026.
(b) Primarily relates to the various new energy storage operating lease agreements that commenced in 2025.
(c) Most of our lease agreements do not contain an implicit rate that is readily determinable. For these agreements we use our incremental borrowing rate to measure the present value of lease liabilities. We determine our incremental borrowing rate at lease commencement based on the rate of interest that we would have to pay to borrow, on a collateralized basis over a similar term, an amount equal to the lease payments in a similar economic environment. We use the implicit rate when it is readily determinable.

18. El Dorado Equity Investments

Equity Method Investments

El Dorado holds investments in equity securities accounted for under the equity method. The equity method of accounting is applied when we have the ability to exercise significant influence over the operating and financial policies of an investee. The equity method has been applied to El Dorado's equity investment holdings in SAI and Copper Sky.

SAI — SAI is a private corporation that manufactures electrical switchgear equipment used by data centers. El Dorado holds common stock in SAI and maintains a seat on SAI's board of directors. El Dorado's ownership increased to 17.99% in the second quarter of 2026 as a result of SAI's Phase 1 repurchases, which reduced the number of outstanding shares.

Copper Sky — Copper Sky, previously AZ-VC, is a limited liability company fund focused on analyzing, investing, managing, and otherwise dealing with investments in privately-held early stage and emerging growth technology companies and businesses primarily based in Arizona, or based in other jurisdictions and having existing or potential strategic or economic ties to companies or other interests in Arizona. El Dorado holds Class A Membership interests in the fund.

These equity method investments are included in the other assets line item on Pinnacle West's Condensed Consolidated Balance Sheets. The following table presents El Dorado's ownership percentages and carrying value of investments accounted for under the equity method (dollars in millions):

Investee	Pinnacle West Ownership Percentage as of June 30, 2026	June 30, 2026	December 31, 2025
SAI (a)	18 %	$ 34	$ 21
Copper Sky (b)	23 %	18	15
Total equity method investments		$ 52	$ 36

(a) El Dorado has no further funding commitments to SAI.
(b) El Dorado has a $25.0 million funding commitment to Copper Sky, previously AZ-VC, of which approximately $18.8 million has been funded as of June 30, 2026.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Our share of the investees' earnings or losses are recognized in other income and other expense, respectively on Pinnacle West's Condensed Consolidated Statements of Income. For the six months ended June 30, 2026, the net equity method earnings relating to these investments was $13.5 million. For the six months ended June 30, 2025, the net equity method earnings relating to these investments was $18.7 million.

Other Investments

El Dorado holds investments in other equity securities to which the equity method of accounting does not apply due to lack of significant influence over the investees' operating and financial policies. These equity investments do not have readily determinable fair values, and we have elected the measurement alternative for these investments. Investments accounted for under the measurement alternative are carried at cost adjusted for impairments or observable price changes. The Pinnacle West Condensed Consolidated Balance Sheets as of June 30, 2026 and December 31, 2025 include $25.7 million and $25.1 million, respectively, relating to these other El Dorado equity investments. These investments are carried at cost, as no impairments or observable price changes have occurred as of June 30, 2026.

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 to the Condensed Consolidated Financial Statements (“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 2025 Form 10-K and Part II, Item 1A of this report.

OVERVIEW

Business Overview

Pinnacle West is an investor-owned electric utility holding company based in Phoenix, Arizona with consolidated assets of approximately $33 billion. We derive essentially all of our revenues and earnings from our principal subsidiary, APS. Since 1886, APS and its affiliates have provided energy and energy-related products to people and businesses throughout Arizona. APS is Arizona’s largest and longest-serving electric company and generates safe, affordable and reliable electricity for approximately 1.5 million retail customers in 11 of Arizona’s 15 counties. APS is also the operator and co-owner of Palo Verde — a primary source of electricity for the southwestern United States. Our other active subsidiaries are El Dorado and PNW Power.

Strategic Overview

Our vision is to create a sustainable energy future for Arizona. Our mission is to serve customers with safe, reliable, and affordable energy. We are committed to delivering operational excellence at the lowest cost possible while aspiring to lower carbon emissions over time.

Reliable

As energy demand in Arizona continues to grow, we remain committed to delivering reliable service to our customers. We have a goal of achieving top quartile reliability as compared to peers. Key elements to delivering reliable service include resource and transmission planning to maintain resource adequacy, distribution automation and resiliency investments, predictive and preventative maintenance programs, seasonal readiness programs, emergency preparedness, and securing a reliable supply chain. Securing a reliable grid requires ongoing infrastructure investments in addition to investments to support new customer growth.

Balanced Energy Mix. APS strives to procure a balanced energy mix, and we believe this provides the greatest reliability at the lowest cost possible while increasing resiliency. We achieve reliability, in part, through a blend of dispatchable resources, such as natural gas and battery storage, that can provide energy when intermittent resources, such as wind and solar, are unavailable. APS regularly evaluates the best mix of resources based on a changing operating environment, including changes in generation technology, economics, and policy impacts.

Currently, additional natural gas capacity is necessary to support reliable service and meet increasing energy needs. However, at this time existing natural gas pipelines into Arizona are fully committed. As a result, in July 2025, APS executed a gas transportation precedent agreement to secure a long-term supply of additional natural gas transportation. The new pipeline is expected to be operational by late 2029 and will be owned and operated by a third party. In July 2026, APS announced plans to convert two units at Cholla to natural gas, adding approximately 380 MW of gas-fired generation. The plan is subject to change pending the comparison to other generation sources that APS is considering in its evaluation of the 2025 ASRFP. The plan contemplates that construction on the gas conversion would begin in 2028 with a targeted in-service date in 2029. In addition to the planned Cholla gas conversion, APS plans to add up to 2,000 MW of flexible natural gas generation to its portfolio, designed to help meet the growing around-the-clock energy needs in Arizona. APS continues to explore additional development opportunities to meet Arizona's growing needs.

Palo Verde, one of the nation's largest carbon-free energy resources, serves as a foundational part of APS's resource portfolio. The plant is a critical asset to the Southwest, generating more than 32 million MWh – enough power for roughly 3.4 million households, or approximately 8.5 million people. Its continued operation is important to a carbon-neutral future for Arizona and the region, as a reliable, continuous, affordable resource and as a large contributor to the local economy. APS owns or leases 29.1% of Units 1, 2, and 3 Palo Verde. In June 2025, APS entered into agreements to purchase two of the three leased interests in Unit 2. The two subject leased interests represented approximately 7% or 94 MW of Unit 2. The transaction closed in September 2025, leaving one remaining lease for approximately 5.2% of Unit 2 that expires in 2033. See Note 9 for more information. The 2025 Rate Case includes pro forma adjustments to account for these acquisitions.

In March 2026, APS announced its intention to renew the operating licenses for all three units at Palo Verde, which would extend operations from the mid-2040s through the mid-2060s. APS continues to evaluate and pursue options for reliably serving growing customer energy needs and demand.

Wildfire Efforts. Wildfire safety remains a critical focus for APS and other utilities. APS has increased investment in fire mitigation efforts to clear defensible space around its infrastructure, continue ongoing system upgrades, build partnerships with government entities and first responders, and educate customers and communities. APS also increased spend on grid technology to enable fast-trip relay response, also known as Enhanced Powerline Safety Settings. These programs contribute to customer reliability, fire ignition avoidance, responsible forest management, and safe communities. With wildfire events occurring across the U.S. and North America over the last few years, APS has been devoting and intends to continue to devote substantial efforts to analyzing and developing enhancements to its systems and processes to mitigate fire risk within its service territory and communities, including by hardening our infrastructure, deploying new technologies where appropriate, increasing situational awareness, implementing operational changes, and enhancing our wildfire response capabilities.

APS uses fire modeling software to identify and calculate risk and target future system improvement investments such as fire-resistant pole wrapping, wood to steel pole conversions, and additional remote-controllable field devices like reclosers and switches. In 2024, APS began installing a system of artificial intelligence-based fire sensing cameras with the ability to detect and alert on fire ignitions. These alerts are sent both to APS and fire response dispatch centers to speed fire response in APS's service territory regardless of the cause of the fire. APS also implemented a public safety power shutoff ("PSPS") program on certain feeders that began in the 2024 fire season, leveraging real-time analysis of weather and environmental factors, such as temperature, humidity, fuel moisture levels, and wind, provided by APS field sensors and the modeling software. APS has educated and will continue education outreach to customers and communities that may potentially be impacted by the PSPS program.

APS was selected by DOE's Grid Deployment Office ("GDO") to receive up to $70 million in federal money for fire mitigation and grid infrastructure projects. This funding is part of the GDO's Grid Resilience and Innovation Partnership Program and is contingent on APS negotiating and executing final grant agreements with GDO. Additionally, on May 12, 2025, the Arizona governor signed into law a bill that requires Arizona electric utilities to develop and seek approval for wildfire mitigation plans and defines the standard of care with respect to wildfire-related claims by reference to such plans. Pursuant to that legislation, APS submitted its Comprehensive Wildfire Mitigation Plan to the Arizona Department of Forestry and Fire Management for review and approval. The wildfire mitigation plan was approved on May 7, 2026. APS continues to evaluate policy and regulatory options, as well as insurance programs, to mitigate the impact of wildfire events.

Affordable

We are committed to keeping bills as low as possible for our customers while maintaining high levels of reliability. Inflation has dramatically impacted the cost of goods and services in recent years, as shown by the Consumer Price Index for All Urban Consumers ("CPI-U"), which from 2018 through 2024 rose nationally 24.9% and 32.1% in Phoenix. Despite this, APS's average residential rates remained well-below those inflation figures, rising 16.2% for the same period according to the U.S. Energy Information Administration. Inflation has recently reached its highest level since 2023, with CPI-U rising 4.2% nationally in the 12 months ended May 2026 and 3.0% in Phoenix over the 12 months ended April 2026. As a result of increased tariffs and supply chain constraints, APS amended several of its agreements from its ASRFP issued in 2023 to mitigate these cost impacts. However, APS remains cautious of potential price increases as a result of ongoing geopolitical events and current and proposed tariffs, which could lead to higher costs and supply chain constraints, while also continuing to monitor the impact of the U.S. Supreme Court's recent decision regarding the validity of certain tariffs and any other related executive or legislative action.

APS's customer affordability initiative includes internal opportunities, such as training and mentoring employees on identifying efficiency opportunities; maintaining inventory to take advantage of lower pricing and avoid expediting fees; entering into long-term contracts to hedge against price volatility, which has allowed APS to mitigate against procurement spend on critical items such as transformers; and implementing automation technologies to enhance efficiencies and increase data-oriented decision making. The customer affordability initiative also includes external opportunities, including a portfolio of customer programs designed to help customers reduce and manage their bills. In the 2025 Rate Case, APS is also seeking to reduce cross-subsidization of customer classes and ensure that growth pays for growth by requesting modifications to its cost allocation methodologies. APS continues to seek opportunities to streamline its business processes, mitigate cost increases, increase employee retention, and improve customer satisfaction.

APS's IRP and competitive ASRFP processes serve important roles in providing reliable and affordable energy to APS's customers. The IRP process helps identify the amount and type of resources required to reliably meet customer needs, while the ASRFP process seeks to meet those needs in a competitive manner based on cost, ability to meet system requirements, and commercial viability.

APS has seen increasing demand from large load customers in recent years. In the 2025 Rate Case, APS requested adjustments to rate designs and modification of cost allocation methodologies to ensure growth pays for growth and reduce cross-subsidization by customer classes. In line with the 2025 Rate Case, APS has developed an approach it believes will allow for these large load customers to fund the incremental infrastructure needed to serve them through long-term contracts where they cover capital costs and assume development risks, accelerating their path to service and ensuring those infrastructure costs are borne by those customers rather than residential or small business customers.

There are also external opportunities that allow APS to deliver more affordable energy to customers, such as APS's participation in western energy markets and programs. APS participated in market design and tariff development of Markets+, a day-ahead and real-time market offering from the Southwest Power Pool. The Markets+ tariff was filed with FERC on March 29, 2024 and was approved on January 16, 2025. APS is a funding party to the implementation phase of Markets+ and expects to go live in the market in late 2027 or early 2028. In addition, APS is participating in the Western Resource Adequacy Program administered by Western Power Pool and plans to transition to full-binding participation in 2027. These regional efforts are driven by the objectives of reducing customer cost and improving reliability. APS will continue to participate in the Western Energy Imbalance Market ("WEIM") as a tool for creating savings for APS's customers from the real-time only, voluntary market for as long as feasible leading up to the transition to Markets+. APS expects that its participation in the WEIM and future participation in Markets+ will lower its fuel and purchased-power costs, improve situational awareness for systems operations in the Western Interconnection, and improve integration of APS's resources.

Resource Planning—Prioritizing Reliability and Affordability

APS remains focused on providing reliable energy at the lowest cost possible while striving to lower emissions over time and continues to look for opportunities to support reliability through traditional dispatchable resources, such as gas and the potential extension of coal beyond 2031. APS's diverse portfolio of existing and planned resources includes biomass, biogas, coal, energy storage, geothermal, natural gas, nuclear, solar, and wind. Every three years, APS performs an IRP, a comprehensive study to identify what resources will be necessary to safely, reliably, and affordably meet the demand and energy needs of its customers over the next 15 years. In November 2023, APS released its latest IRP, which identified forecasted customer demand and energy needs growing at an unprecedented rate. In developing the IRP, APS considered how factors such as forecasted economic growth, impacts from weather, and new resource technology availability impact the amount and type of resources required to reliably and affordably meet customer needs. These factors, among others, were used to develop a plan that identified a balanced mix of diverse energy-generating resources to reliably serve customers' future energy needs. APS expects to file its next IRP on October 30, 2026, which will provide an updated view on the resource types and volumes necessary to maintain reliability for a rapidly expanding customer base. To help ensure competitive costs for resources procured by APS, APS regularly issues competitive bid solicitations through the ASRFP process, with the most recent ASRFP being issued in 2025. These ASRFPs are open to bids for all resource types, including customer-scale (behind the meter) and utility-scale (in front of the meter) resources.

APS selects projects out of ASRFPs based on cost, ability to meet system requirements, and commercial viability, taking into consideration timing and likelihood of successful contracting and development. Guided by IRP-established timelines and quantities, APS maintains a flexible approach that allows it to optimize system reliability and customer affordability through the ASRFP process. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection to the electric grid. Consistent with recent ASRFPs, APS remains focused on contracting for resources that can withstand supply chain pressures and volatility and seeks a balanced portfolio that is resilient to other external pressures, including those arising from the macroeconomic and geopolitical environment.

In terms of recent solicitations, APS issued an ASRFP on June 30, 2023, pursuant to which APS procured 3,606 MW of battery storage, 517 MW of natural gas, 2,649 MW of solar, and 500 MW of wind resources expected to be in service from 2026 to 2028. APS issued another ASRFP on November 20, 2024, pursuant to which it signed an amendment and extension to each of two existing gas tolling agreements, securing 600 MW under each agreement through 2038 and 2046, respectively. The scope of projects being negotiated out of the 2024 ASRFP reflects both the expanse of the 2023 ASRFP and the reality of adjusting to tariffs and changing federal policy.

In its most recent ASRFP, issued on November 19, 2025, APS is seeking at least 1,000 MW of resources that can reach commercial operation between 2029 and 2031, but APS will also consider projects that can achieve commercial operation earlier or later.

APS has an aspirational goal to be carbon-neutral by 2050. This means that for any GHG emissions still produced by our generation resources as of 2050, we will aim to offset these emissions elsewhere. This goal reflects APS's interest in new generation and energy storage innovation and market transformations that address carbon emissions, while relying on the IRP and ASRFP processes to help determine the path forward.

Customer-Focused

Serving customers with excellence is foundational to APS's business and remains our core focus as we adapt to evolving customer needs and emerging technology. Recognizing that every employee impacts our customer experience, we continue to provide information, tools, and resources enabling our teams to design, develop, and implement enhancements to improve our customer experience.

APS's 24/7 call center answers more than 75% of customer calls within 30 seconds, and our mobile platforms enable our customers to quickly and easily find the information they need when they need it. We seek to provide relevant and valuable options for customers to manage their bill, including through rate plan options, programs that help them save energy and money, and alerts and notifications that help keep them aware of outages, payments, and usage. APS has a high-bill analyzer tool enabling phone advisors to provide customers with specific, customized guidance based on their actual usage and habits. For customers experiencing higher-than-expected bills, APS's high-bill analyzer tool allows phone advisors to provide specific, customized guidance based on a customer's actual energy-use patterns.

Additionally, APS offers a variety of customer assistance resources, including income-qualified bill discounts of up to 60% for eligible customers, flexible payment arrangements and emergency utility bill assistance. To ensure customers are aware of and connected to these resources, APS partners with nearly one hundred community action agencies across our service territory, providing training and support to representatives who serve our shared customers. Through these partnerships and programs, APS works to ensure assistance is available to customers when they need it most.

Developing Technologies

New Nuclear Generation. Along with other Arizona electric utilities, APS is exploring additional nuclear generation to provide around-the-clock carbon-free energy to meet rising energy demands in Arizona. APS has been monitoring emerging nuclear technologies, ranging from newer proposed and installed versions of large-scale reactors to small modular nuclear reactors. Small modular nuclear reactors are typically designed to generate 300 MW or less of energy per unit compared to, for example, the 1,400 MW per unit generated at Palo Verde. The Arizona electric utilities have begun preliminary exploration of a potential site for additional nuclear energy for Arizona.

Long Duration Energy Storage. Continued technological innovation in long duration energy storage, which represents storage products which provide more than four hours of service, has led to decreasing cost of these solutions and an increase in their procurement, development, and deployment. These solutions include lithium and non-lithium battery chemistries, alternative natural gas-fired fuel cells and turbine units, and pumped hydropower. We will continue to evaluate these technologies and their ability to provide reliability, affordability, and balance to our portfolio.

Carbon Capture. CCS technologies can isolate carbon dioxide and either sequester it permanently in geologic formations or convert it for use in products. Currently, almost all existing fossil fuel generators do not control carbon emissions the way they control emissions of other air pollutants such as sulfur dioxide or oxides of nitrogen. CCS technologies are still in the demonstration phase and while they show promise, they are still being tested in real-world conditions. These technologies could potentially reduce carbon emissions from fossil fuel-fired generation.

Artificial Intelligence. To address the rapid advancement of AI technology risks and opportunities, APS has developed an AI strategy to responsibly utilize AI to advance our business strategy, enhance customer and employee experiences, and optimize operational reliability. At the core of our AI strategy is a focus on cultural transformation and workplace adoption of AI skills, supported by a robust governance model that guides the development of policies and strategies for the execution of AI projects at the Company. To ensure compliance with data security, reliability requirements, and our Code of Ethical Conduct, governance and oversight are provided by leadership and experts from our information technology, cybersecurity, human resources, ethics, supply chain, legal, and nuclear generation teams.

Regulatory Overview

2025 Rate Case

On June 13, 2025, APS filed the 2025 Rate Case application with the ACC seeking a net base rate increase of $579.5 million, which represents a 13.99% net increase. The requested net increase addresses a total base revenue deficiency of $662.4 million, offset by proposed adjustor transfers of cost recovery to base rates.

The 2025 Rate Case application includes the following proposals:

- a test year comprised of the 12-month period ended on December 31, 2024, including certain pro forma adjustments;
- 12 months of post-test year plant placed into service from January 1, 2025 through December 31, 2025;
- an original cost rate base of $12.5 billion, which approximates the ACC-jurisdictional portion of the book value of utility assets, net of accumulated depreciation and other credits;

- the following proposed capital structure and costs of capital:

	Capital Structure	Cost of Capital
Long-term debt	47.65 %	4.26 %
Common stock equity	52.35 %	10.70 %
Weighted-average cost of capital		7.63 %

- a 1% return on the increment of fair value rate base above APS's original cost rate base, as provided for by Arizona law;
- a rate of $0.043881 per kWh for the portion of APS's base rates attributable to fuel and purchased power costs;
- adjustments to rate designs, including direct assignment of costs, to reduce cross-subsidization by certain customer classes;
- modification of cost allocation methodologies based on customer growth to ensure customers causing new production costs are covering those costs through rates, along with corresponding changes to adjustor mechanisms, such as for fuel and purchased power;
- implementation of a FRAM to assist with reducing regulatory lag and allow for rate gradualism;
- elimination of the LFCR following the first annual adjustment pursuant to the FRAM; and
- modification to the SRB due to the FRAM proposal.

On March 2 and March 18, 2026, the ACC Staff, RUCO, and other intervenors filed their initial written testimony with the ACC. ACC Staff's testimony includes the following recommendations, among others, depending on the approval of APS's proposed FRAM, (i) a $525.2 million total base revenue increase, (ii) a 9.55% to 9.80% return on equity, (iii) a 0.20% return on the increment of fair value, and (iv) 12 months of post-test year plant. RUCO's testimony includes the following recommendations, among others, depending on the approval of APS's proposed FRAM, (i) a $200.2 to $278.1 million total base revenue increase, (ii) a 9.00% to 9.20% return on equity, (iii) a 0.0% return on the increment of fair value, and (iv) 0 to 12 months of post-test year plant.

On April 3, 2026 , APS filed rebuttal testimony addressing the ACC Staff and intervenors' direct testimonies. The principal provisions of APS's rebuttal testimony are as follows:

- a total revenue requirement increase of $694.2 million, or a net revenue requirement increase of $611.3 million after adjustor transfers;
- maintaining a return on equity request of 10.7%;
- reducing the return on the increment of fair value from 1.0% to 0.9%;
- maintaining a post-test year plant request of 12 months and updating the impacted projects, including Ironwood solar and Sundance; and
- an integrated set of FRAM modifications that are intended to be evaluated together:
    - allowing for an earnings test "deadband" range of +/- 40 basis points to APS's authorized return before an adjustment to the FRAM would be required;
    - limiting projected plant to six months;
    - elimination of the SRB and TEAM following the first annual adjustment pursuant to the FRAM;
    - retention of the 120-day review and challenge period; and
    - elimination of the interim rate reset by accepting Commission approval prior to implementation (subject to an automatic reversion provision).

On May 1, 2026, ACC Staff, RUCO, and other intervenors filed their surrebuttal testimonies with the ACC. The ACC Staff adjusted their initial recommendation to a $506.5 million total base revenue increase and additional revisions to the Company's FRAM proposal, including the continued recommendation for an earnings test "deadband" range of +/- 50 basis points.

On May 11, 2026, APS filed its rejoinder testimony addressing the ACC Staff and intervenors' surrebuttal testimonies. APS's rejoinder testimony included adjustments to the proposed schedule for the annual FRAM filing and a reduction of the total revenue requirement increase to $691.6 million, representing a revenue requirement increase, net of adjustor transfers, of $608.7 million. All other major provisions from APS's rebuttal testimony were maintained in its rejoinder testimony.

APS requested that the increase become effective in the second half of 2026. The hearing concluded on July 7, 2026. After the conclusion of the hearing, the Administrative Law Judge overseeing the hearing issued a procedural order outlining briefing schedules and other next steps in the proceedings. The order noted that the case is anticipated to be resolved before the end of this year. APS cannot predict the outcome of its request nor when the 2025 Rate Case will be decided by the ACC.

2022 Rate Case

On October 28, 2022, APS filed an application with the ACC (the "2022 Rate Case") for an increase in retail base rates, and on January 25, 2024, an Administrative Law Judge issued a ROO, as corrected on February 6, 2024 (the "2022 Rate Case ROO").

On February 22, 2024, the ACC approved the 2022 Rate Case ROO with certain amendments that resulted in, among other things, (i) an approximately $491.7 million increase in the annual base revenue requirement, (ii) a 9.55% return on equity, (iii) a 0.25% return on the increment of fair value rate base greater than original cost, (iv) an effective fair value rate of return of 4.39%, (v) a return set at the Company's weighted average cost of capital on the net prepaid pension asset and net other post-employment benefit liability in rate base, (vi) an adjustment to generation maintenance and outage expense to reflect a more reasonable level of test year costs, (vii) approval of the SRB mechanism with modifications to customer notifications, procedural timelines and the inclusion of any qualifying technology and fuel source bid received through an ASRFP, and (viii) recovery of all DSM costs through the DSM Adjustment Charge ("DSMAC") rather than through base rates.

The ACC issued the final order for the 2022 Rate Case on March 5, 2024, with the new rates becoming effective for all service rendered on or after March 8, 2024.

Six intervenors and the Attorney General of Arizona requested rehearing on various issues included in the ACC's decision, such as the GAC for solar customers, the SRB, and Coal Community Transition funding. On April 15, 2024, the ACC granted, in part, the rehearing applications of the Attorney General, AriSEIA, SEIA, and Vote Solar specifically to review whether the GAC rate is just and reasonable, including whether it should be higher or lower, whether the GAC rate constitutes a discriminatory fee to solar customers, and whether omission of a GAC charge is discriminatory to non-solar customers. All other applications for rehearing were denied. A limited rehearing was held October 28 through November 1, 2024. Following the limited rehearing, an Administrative Law Judge issued the Limited Rehearing ROO on December 3, 2024, which recommended affirming the GAC as just and reasonable and that the GAC is not discriminatory to solar customers and the absence of a GAC is not discriminatory to non-solar customers. On December 17, 2024, the ACC approved the Limited Rehearing ROO with an amendment that requires APS in its next rate case to propose a revenue allocation based on a site-load cost of service study in order to bring further parity in revenue collection between solar and non-solar customers. SEIA, AriSEIA, Vote Solar, the Arizona Attorney General, and two individual customers have filed requests for rehearing of the ACC's December 17, 2024 decision on the rehearing. The ACC has taken no action on these requests. In addition, each of these parties has subsequently filed an appeal to the Arizona Court of Appeals seeking review of the ACC's decisions regarding the GAC and on rehearing. On February 25, 2026, parties provided oral arguments before the Court of Appeals. On June 16, 2026, the Arizona Court of Appeals found that the GAC and related increases for residential solar customers were imposed by the ACC without adequate notice or opportunity to be heard. APS has since moved for reconsideration of this decision and, if reconsideration is not successful, plans to seek further review of this decision before the Arizona Supreme Court. APS cannot predict the outcome of these proceedings, but does not expect the outcome will have a material impact on APS' financial position, results of operations, or cash flows.

Regulatory Lag Docket

On January 5, 2023, the ACC opened a new docket to explore the possibility of modifications to the ACC's historical test year rules. The ACC requested comments and held two workshops exploring ways to reduce regulatory lag, including alternative ratemaking structures such as future test years, hybrid test years, and formula rates. On December 3, 2024, the ACC approved a policy statement regarding formula rate plans. The policy statement provides regulated utilities with the opportunity to propose formula rate plans in future rate cases. On March 28, 2025, RUCO, the ALCG, and an individual customer filed a lawsuit challenging the ACC's authority to issue the formula rate policy statement outside of Arizona's formula rulemaking process. On June 13, 2025, the lawsuit challenging the ACC's formula rate policy was dismissed by the Superior Court of Maricopa County. Following the dismissal, the plaintiffs filed an appeal with the Arizona Court of Appeals as well as a Petition for Special Action with the Arizona Supreme Court. The Supreme Court declined to exercise jurisdiction on the Petition for Special Action. The plaintiffs also filed a Petition for Special Action with the Arizona Court of Appeals, which has accepted jurisdiction to determine whether the case should be remanded back to the Superior Court for expedited consideration of the merits. On November 21, 2025, the Arizona Court of Appeals ruled that the issue should be remanded back to the Superior Court to determine whether the ACC's formula rate policy must go through a formal rulemaking process. In response, APS, the ACC, and several other Arizona utility companies filed petitions for review of the Court of Appeals decision with the Arizona Supreme Court. That petition was denied on May 8, 2026, which will return the litigation to the Superior Court of Maricopa County for further proceedings on the merits of whether the ACC's issuance of the formula rate policy statement complied with the Arizona Administrative Procedure Act. APS cannot predict the outcome of this matter or the impact (if any) it may have on other proceedings.

See Note 7 for more information regarding these and additional regulatory matters.

Captive Insurance Cell

Pinnacle West is the primary beneficiary of a protected cell captive insurance cell. The Captive provides insurance coverage to Pinnacle West and our subsidiaries that supplements commercial and mutual insurance coverage. The Captive insures Pinnacle West and its subsidiaries for terrorism coverage, excess liability including certain wildfire coverage, excess property insurance, and excess employment practice liability. The Captive policies exclude nuclear liability at Palo Verde. See Note 9. The Captive may hold investment assets in cash, cash equivalents, and equity and fixed income instruments.

Tax Incentives

The IRA significantly expanded the availability of tax credits for investments in clean energy generation technologies and energy storage. Key provisions included (i) an extension of tax credits for solar and wind generation, including a new option for solar investments to claim a PTC in lieu of the ITC beginning in 2022; (ii) expansion of the ITC to cover stand-alone energy storage technology beginning in 2023; (iii) introduction of technology neutral clean energy ITCs and PTCs beginning in 2025; and (iv) introduction of a new Nuclear PTC, available from 2024 through 2032.

On July 4, 2025, the One Big Beautiful Bill Act ("OBBBA") was signed into law. The OBBBA curtailed several clean energy tax credits initially passed in the IRA, including a new phase out deadline for wind and solar ITCs and PTCs that requires projects to either begin construction within one year of enactment or be placed in service by December 31, 2027. Additionally, the OBBBA contained provisions restricting clean energy projects, including energy storage, which begin construction after December 31, 2025, and receive "material assistance from a prohibited foreign entity," from being eligible for clean energy ITCs or PTCs.

The Company believes that its projects which are currently under construction will continue to qualify for IRA tax credits. See Note 5 for information on Palo Verde's Nuclear PTC. The Company is continuing to analyze the OBBBA and is awaiting regulations and other guidance as to the application of these new rules to projects not currently under construction.

Financial Strength and Flexibility

We believe that 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 are anticipated to be funded with internally generated cash and external financings, which may include issuances of long-term debt and Pinnacle West common stock.

Other Subsidiaries

PNW Power

PNW Power holds certain investments and assets that were previously held by BCE, a former subsidiary of Pinnacle West that was sold in 2024. PNW Power's investments include TransCanyon, a 50/50 joint venture that was formed in 2014 with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. TransCanyon is pursuing independent electric transmission opportunities within the 11 U.S. states that comprise the Western Interconnection, excluding opportunities related to transmission service that would otherwise be provided under the tariffs of the retail service territories of the TransCanyon partners' utility affiliates. These opportunities include the proposed 500-kV Cross-Tie transmission project (the "Cross-Tie Project"), which includes a 214-mile transmission line connecting Utah and Nevada that is intended to help improve grid reliability and relieve congestion on other transmission lines. On December 18, 2025, the Department of Interior Bureau of Land Management issued a Record of Decision permitting the development of Cross-Tie Project, which became non-appealable in late January 2026.

PNW Power's investments also include minority ownership positions in two wind farms operated by Tenaska Energy, Inc. and Tenaska Energy Holdings, LLC, the 242 MW Clear Creek and the 250 MW Nobles 2 wind farms. Clear Creek achieved commercial operation in May 2020; however, in the fourth quarter of 2022, PNW Power's equity method investment was fully impaired. Nobles 2 achieved commercial operation in December 2020. Both wind farms deliver power under long-term PPAs. PNW Power indirectly owns 9.9% of Clear Creek and 5.1% of Nobles 2.

El Dorado

El Dorado owns debt investments and minority interests in several energy-related investments and Arizona community-based ventures. In particular, El Dorado has committed to and/or holds the following:

- $25 million investment in the Energy Impact Partners fund, of which approximately $21 million has been funded as of June 30, 2026. Energy Impact Partners is an organization that focuses on fostering innovation and supporting the transformation of the utility industry.

- $25 million investment in Copper Sky, previously AZ-VC, of which approximately $19 million has been funded as of June 30, 2026. Copper Sky is a fund focused on analyzing, investing, managing, and otherwise dealing with investments in privately-held early stage and emerging growth technology companies and businesses primarily based in Arizona, or based in other jurisdictions and having existing or potential strategic or economic ties to companies or other interests in Arizona.

- $7.5 million investment in Westly Seed Fund, of which approximately $2 million has been funded as of June 30, 2026. Westly Seed Fund is focused on supporting entrepreneurs involved in the energy, mobility, building, and industrial sectors.

- Equity investment in SAI, a private corporation that manufactures electrical switchgear equipment used by data centers. El Dorado accounts for this investment under the equity method and has an investment carrying value of approximately $34 million as of June 30, 2026.

The remainder of these investment commitments will be contributed by El Dorado as each investment fund selects and makes investments.

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 2025, retail electric revenues were 95% of our total operating revenue. For 2023 through 2025, retail electric revenues averaged approximately 94% of our total operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, distributed energy additions, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery mechanisms. Our revenues are affected by the availability of excess generation or other energy resources and wholesale market conditions, including competition, demand, and prices.

Actual and Projected Customer and Sales Growth. Retail customers in APS's service territory increased 2.1% for the period ended June 30, 2026 compared with the prior-year period. For the three years through 2025, APS's customer growth averaged 2.2% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2026 and the average annual growth to be in the range of 1.5% to 2.5% through 2030 based on anticipated steady population growth in Arizona during that period.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 3.9% for residential customers, 13.6% for commercial and industrial customers, 3.9% for residential customers, and 9.5% for all retail customers for the period ended June 30, 2026 compared with the prior-year period. While strong sales to commercial and industrial customers continue to be driven by the ramp-up of new data center and large manufacturing customers, the main drivers of increased revenues for this period were a surge in residential usage during April and May, including on days with normal weather conditions, following strong weather-driven demand caused by a record-setting March heat wave in Arizona in the first quarter of 2026 and steady customer growth, which was only partially offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation. Due to the growth of large load customers as a proportion of our business, in the first quarter of 2025, we updated our procedures with respect to estimates of unbilled revenues. This resulted in a downward adjustment to unbilled revenues in that quarter, which contributes approximately 0.9% to 2026 year-to-date sales growth as compared to the same period last year.

For the three years through 2025, annual retail electricity sales growth averaged 3.9%, adjusted to exclude the effects of weather variations. Due to the expected growth of several data centers and large manufacturing facilities, we currently project that annual retail electricity sales in kWh will increase in the range of 4.0% to 6.0% for 2026 and that average annual growth will be in the range of 5.0% to 7.0% through 2030, including the effects of customer conservation, energy efficiency, and distributed renewable generation, but excluding the effects of weather variations. These projected sales growth ranges include the impacts of several data centers and large manufacturing facilities, which are expected to contribute to 2026 growth in the range of 3.0% to 5.0% and to average annual growth in the range of 4.0% to 6.0% through 2030.

Longer term, APS has been preparing for and can serve significant load growth from residential and business customers. On top of these existing growth trends, APS is also receiving incremental requests for service from large load customers with very high energy demands that persist virtually around-the-clock, such as data centers for AI and large manufacturers. These incremental requests for service by large load customers far exceed available generation and transmission resource capacity in the Southwest region for the foreseeable future. Because of the high growth in demand for such projects, APS has developed a queue that identifies and prioritizes projects while maintaining system reliability and affordability for existing APS customers. APS is also exploring available options for developing additional electric generation and transmission to meet these projections of future customer needs as a part of the company's "growth pays for growth" strategy, such as long-term contracts with large load customers to pay for the costs associated with the incremental infrastructure needed to provide service without compromising reliability and affordability for existing customers.

Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as macroeconomic conditions, current and future economic, regulatory, business, and other conditions, such as the Arizona housing market, customer growth, usage patterns and energy conservation, slower ramp-up of and/or fewer large data centers and manufacturing facilities, slower than expected commercial and industrial expansions, impacts of energy efficiency programs and growth in DG, responses to retail price changes, changes in regulatory standards, and impacts of new and existing laws and regulations, including environmental laws and regulations. Based on past experience, a 1% variation in our annual residential and small commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $25 million, and a 1% variation in our annual large commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $7 million.

Weather. In forecasting the retail sales growth numbers provided above, we assume normal weather patterns based on historical data. Our experience indicates that typical variations from normal weather can result in increases and decreases in annual net income of up to $30 million. However, since 2020, extreme weather events, such as record-setting summer heat and decreased annual precipitation in our service territory, have resulted in increases in annual net income that are more than historically typical on average.

Fuel and Purchased Power Expenses. Fuel and purchased power expenses 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 DSM related expenses (which are mostly offset by the same amount of operating revenues) and other factors.

Depreciation and Amortization Expenses. Depreciation and amortization expenses are impacted by net additions to utility plant and other property (such as new generation, transmission, and distribution facilities), and increases in intangible assets and changes in depreciation and amortization rates. See “Liquidity and Capital Resources” below for information regarding the planned additions to our facilities.

Pension and Other Postretirement Non-Service Credits, Net. Pension and other postretirement non-service credits can be impacted by changes in our actuarial assumptions. The most relevant actuarial assumptions are the discount rate used to measure our net periodic costs/credit, the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term, mortality assumptions and assumed healthcare cost trend rates. We review these assumptions on an annual basis and adjust them, as necessary. See Note 8.

Property Taxes. Taxes other than income taxes consist primarily of property taxes, which are affected by changes in plant balances related to new investments and improvements to existing facilities, 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 9.6% of the assessed value for 2025, 9.7% for 2024, and 10.0% for 2023.

Income Taxes. Income taxes are affected by the amount of pretax book income, income tax rates, certain deductions, certain credits and non-taxable items, such as AFUDC. In addition, income taxes may also be affected by the settlement of issues with taxing authorities.

Interest Expense. Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. See Note 6 for further details. The primary factors affecting borrowing levels are expected to be our capital expenditures, long-term debt maturities, equity issuances and internally generated cash flow. AFUDC offsets a portion of interest expense while capital projects are under construction. We stop accruing AFUDC on a project when it is placed into service.

RESULTS OF OPERATIONS

Pinnacle West's reportable business segment is our regulated electricity segment, which consists of retail and wholesale sales supplied under traditional cost-based regulation and related activities and includes electricity generation, transmission, and distribution. Our reportable segment activities are conducted through our wholly-owned subsidiary, APS. All other operating segment activities are insignificant to Pinnacle West.

Operating Results – Three-month period ended June 30, 2026, compared with three-month period ended June 30, 2025.

Our consolidated net income attributable to common shareholders for the three months ended June 30, 2026 was $179 million, compared with consolidated net income attributable to common shareholders of $193 million for the prior-year period. The results reflect a decrease of approximately $14 million, primarily as a result of higher interest charges, higher depreciation and amortization expenses mostly due to increased plant additions, partially offset by operations ceasing at Cholla, and lower transmission service revenues. These negative factors were partially offset by the favorable impacts of the effects of weather, increased customer usage, customer growth, lower operations and maintenance expenses, and lower income taxes. Customer growth in turn was partially offset by the related pricing and the impacts of energy efficiency.

The following table presents net income attributable to common shareholders compared with the prior year for Pinnacle West consolidated and for APS consolidated (dollars in millions):

	Pinnacle West Consolidated			APS Consolidated		
	Three Months Ended June 30,			Three Months Ended June 30,		
	2026	2025	Net Change	2026	2025	Net Change
Operating revenues	$ 1,456	$ 1,359	$ 97	$ 1,456	$ 1,359	$ 97
Fuel and purchased power	(558)	(477)	(81)	(558)	(477)	(81)
Operating revenues less fuel and purchased power (a)	898	882	16	898	882	16
Operations and maintenance	(283)	(287)	4	(281)	(285)	4
Depreciation and amortization	(243)	(229)	(14)	(243)	(229)	(14)
Taxes other than income taxes	(62)	(58)	(4)	(62)	(58)	(4)
Allowance for equity funds used during construction	17	15	2	17	15	2
Pension and other postretirement non-service credits, net	5	4	1	5	4	1
Other income and (expense), net	2	7	(5)	(8)	(2)	(6)
Interest charges, net of allowance for borrowed funds used during construction	(122)	(102)	(20)	(97)	(80)	(17)
Income taxes	(31)	(35)	4	(36)	(39)	3
Less: Net income attributable to noncontrolling interests	(2)	(4)	2	(2)	(4)	2
Net Income Attributable to Common Shareholders	$ 179	$ 193	$ (14)	$ 191	$ 204	$ (13)

(a) Operating revenues less fuel and purchased power is a non-GAAP financial measure. As reconciled in the table above, this amount is derived by the difference between the GAAP financial statement line item Operating revenues less the GAAP financial statement line item Fuel and purchased power as presented on the Condensed Consolidated Statements of Income. Operating revenues, less fuel and purchased power is used by Pinnacle West to assess whether customer revenues adequately cover fuel and purchased power costs. This metric is not defined by GAAP and may differ from similar measures used by other companies. This measure is not a substitute for operating income under GAAP.

Operating revenues less fuel and purchased power. Operating revenues less fuel and purchased power expenses were $16 million higher for the three months ended June 30, 2026 compared with the prior-year period. The following table summarizes the major components of this change (dollars in millions):

	Increase (Decrease)		
	Operating revenues	Fuel and purchased power	Net change
Effects of weather	$ 27	$ 8	$ 19
Higher retail revenues due to changes in usage patterns, and customer growth, partially offset by the related pricing and impacts of energy efficiency	49	31	18
LFCR revenue (Note 7)	3	—	3
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	36	40	(4)
Lower transmission revenues (Note 7)	(12)	—	(12)
Lower renewable energy regulatory surcharges, partially offset by lower operations and maintenance costs	(13)	3	(16)
Miscellaneous items, net	7	(1)	8
Total	$ 97	$ 81	$ 16

Operations and maintenance. Operations and maintenance expenses decreased $4 million for the three months ended June 30, 2026 compared with the prior-year period primarily due to:

- a decrease of $18 million related to costs for renewable energy programs and similar regulatory programs, which are partially offset in operating revenues and purchased power;
- a decrease of $1 million related to non-nuclear generation costs, primarily due to lower planned outages;
- an increase of $2 million related to information technology costs;
- an increase of $2 million related to employee benefit costs;
- an increase of $4 million related to nuclear generation costs;
- an increase of $4 million related to transmission, distribution, and customer service costs;
- an increase of $5 million related to corporate resource costs; and
- a decrease of $2 million for other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $14 million higher for the three months ended June 30, 2026 compared to the prior-year period, primarily due to increased plant in service, partially offset by operations ceasing at the Cholla plant.

Other income and expense, net. Other income and expense, net was $5 million lower for the three months ended June 30, 2026 compared to the prior-year period, primarily due to lower PSA interest income and higher other expenses, partially offset by investment gains in the Captive. The difference between APS's and Pinnacle West's other income and expense, net is primarily related to Pinnacle West's investment gains in the Captive.

Interest charges, net of allowance for borrowed funds and equity funds used during construction. Interest charges, net of allowance for funds used during construction, were $18 million higher for the three months ended June 30, 2026 compared to the prior-year period, primarily due to higher debt balances, partially offset by higher allowance for equity funds used during construction.

Taxes other than income taxes. Taxes other than income taxes were $4 million higher for the three months ended June 30, 2026, compared to the prior-year period, primarily due to higher plant balances.

Income taxes. Income taxes were $4 million lower for the three months ended June 30, 2026 compared with the prior-year period, primarily due to lower pre-tax income.

Operating Results – Six-month period ended June 30, 2026, compared with six-month period ended June 30, 2025.

Our consolidated net income attributable to common shareholders for the six months ended June 30, 2026 was $211 million, compared with consolidated net income attributable to common shareholders of $188 million for the prior-year period. The results reflect an increase of approximately $23 million, primarily as a result of the effects of weather, increased usage and customer growth, lower operations and maintenance expenses, and higher transmission service revenues. Customer growth in turn was partially offset by the related pricing and the impacts of energy efficiency. These positive factors were partially offset by higher interest charges, lower other income mainly due to higher El Dorado other income recognized in the prior year, and higher depreciation and amortization expenses mostly due to increased plant additions and intangible assets, partially offset by operations ceasing at Cholla.

The following table presents net income attributable to common shareholders compared with the prior year for Pinnacle West consolidated and for APS consolidated (dollars in millions):

	Pinnacle West Consolidated			APS Consolidated		
	Six Months Ended June 30,			Six Months Ended June 30,		
	2026	2025	Net Change	2026	2025	Net Change
Operating revenues	$ 2,605	$ 2,391	$ 214	$ 2,605	$ 2,391	$ 214
Fuel and purchased power	(995)	(857)	(138)	(995)	(857)	(138)
Operating revenues less fuel and purchased power (a)	1,610	1,534	76	1,610	1,534	76
Operations and maintenance	(560)	(587)	27	(554)	(582)	28
Depreciation and amortization	(483)	(464)	(19)	(483)	(464)	(19)
Taxes other than income taxes	(124)	(117)	(7)	(124)	(117)	(7)
Allowance for equity funds used during construction	32	28	4	32	28	4
Pension and other postretirement non-service credits, net	9	7	2	9	7	2
Other income and (expense), net	1	22	(21)	(10)	2	(12)
Interest charges, net of allowance for borrowed funds used during construction	(238)	(197)	(41)	(189)	(159)	(30)
Income taxes	(32)	(29)	(3)	(44)	(36)	(8)
Less: Net income attributable to noncontrolling interests	(4)	(9)	5	(4)	(9)	5
Net Income Attributable to Common Shareholders	$ 211	$ 188	$ 23	$ 243	$ 204	$ 39

(a) Operating revenues less fuel and purchased power is a non-GAAP financial measure. As reconciled in the table above, this amount is derived by the difference between the GAAP financial statement line item Operating revenues less the GAAP financial statement line item Fuel and purchased power as presented on the Condensed Consolidated Statements of Income. Operating revenues, less fuel and purchased power is used by Pinnacle West to assess whether customer revenues adequately cover fuel and purchased power costs. This metric is not defined by GAAP and may differ from similar measures used by other companies. This measure is not a substitute for operating income under GAAP.

Operating revenues less fuel and purchased power. Operating revenues less fuel and purchased power expenses were $76 million higher for the six months ended June 30, 2026 compared with the prior-year period. The following table summarizes the major components of this change (dollars in millions):

	Increase (Decrease)		
	Operating revenues	**Fuel and purchased power**	**Net change**
Effects of weather	$ 57	$ 16	$ 41
Higher retail revenues due to changes in usage patterns, and customer growth, partially offset by the related pricing and the impacts of energy efficiency	93	55	38
Higher transmission revenues (Note 7)	15	—	15
LFCR revenue (Note 7)	6	—	6
Lower renewable energy regulatory surcharges, partially offset by lower operations and maintenance costs	(22)	5	(27)
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	61	61	—
Miscellaneous items, net	4	1	3
Total	$ 214	$ 138	$ 76

Operations and maintenance. Operations and maintenance expenses decreased $27 million for the six months ended June 30, 2026 compared with the prior-year period, primarily due to:

- a decrease of $28 million related to costs for renewable energy programs and similar regulatory programs, which are partially offset in operating revenues and purchased power;
- a decrease of $15 million related to non-nuclear generation costs, primarily due to lower planned outages;
- a decrease of $5 million related to information technology costs;
- an increase of $4 million related to employee benefit costs;
- an increase of $6 million related to transmission, distribution, and customer service costs;
- an increase of $6 million related to nuclear generation costs;
- an increase of $9 million related to corporate resource costs; and
- a decrease of $4 million for other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $19 million higher for the six months ended June 30, 2026 compared to the prior-year period, primarily due to increased plant in service and intangible assets, partially offset by lower depreciation expense due to operations ceasing at the Cholla plant.

Other income and expense, net. Other income and expense, net was $21 million lower for the six months ended June 30, 2026 compared to the prior-year period, primarily due to lower other income from El Dorado, lower PSA interest income and higher other expenses. The difference between APS's and Pinnacle West's other income and expense, net is primarily related to Pinnacle West's other income from El Dorado.

Interest charges, net of allowance for borrowed funds and equity funds used during construction. Interest charges, net of allowance for funds used during construction, were $37 million higher for the six months ended June 30, 2026 compared to the prior-year period, primarily due to higher debt balances, partially offset by higher allowance for equity funds used during construction.

Taxes other than income taxes. Taxes other than income taxes for the for the six months ended June 30, 2026 were $7 million higher, compared to the prior-year period, primarily due to higher plant balances.

Income taxes. Income taxes were $3 million higher for the six months ended June 30, 2026 compared with the prior-year period, primarily due to higher pre-tax income, partially offset by higher tax credits.

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 does not allow APS to pay common dividends if the payment would reduce its common equity ratio below 40%. Per 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. As of June 30, 2026, APS's common equity ratio, as defined, was 51%. APS's total shareholder equity was approximately $9.0 billion, and total capitalization, as calculated pursuant to the ACC order, was approximately $17.8 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $7.1 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.

Dividends to Pinnacle West from APS are also dependent on a number of factors including, among others, APS's financial condition and free cash flow, the sources of which vary from quarter-to-quarter due in part to the seasonal nature of electricity demand in Arizona. APS's sources of cash include cash from operations and external sources of liquidity, including long- and short-term external debt financing such as commercial paper, term loans and its revolving credit facility. Cash from operations is dependent upon, among other things, the rates APS may charge and the timeliness of recovering costs incurred through its rates and adjustor recovery mechanisms. Regulatory lag may delay recovery and affect operating cash flows. 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 financings and equity infusions from Pinnacle West. On December 17, 2024, the ACC issued a financing order approving a limit on yearly equity infusions equal to 2.5% of APS's total assets each calendar year on a three-year rolling average basis, subject to APS's equity ratio remaining below the most recently approved rate case capital structure plus 50 basis points. On July 31, 2026, APS submitted an application to the ACC requesting to increase the long-term debt limit from $9.5 billion to $12 billion. APS cannot predict the outcome of this matter.

Pinnacle West and APS maintain committed revolving credit facilities that enhance liquidity and provide credit support for accessing commercial paper markets. These credit facilities mature in 2031.

Pinnacle West has an ATM Program under which Pinnacle West may offer and sell Pinnacle West common stock and enter into forward sale agreements from time to time, subject to market conditions and other factors. Pinnacle West also has forward sale agreements from an equity offering in February 2024 in effect as of June 30, 2026. See "Financing Cash Flows and Liquidity—Equity Offerings" below and Note 13 for more information.

Summary of Cash Flows

The following tables present net cash provided by (used for) operating, investing and financing activities (dollars in millions):

Pinnacle West Consolidated

	Six Months Ended June 30,		
	2026	2025	Net Change
Net cash flow provided by operating activities	$ 629	$ 663	$ (34)
Net cash flow used for investing activities	(1,200)	(1,253)	53
Net cash flow provided by financing activities	574	605	(31)
Net increase in cash and cash equivalents	$ 3	$ 15	$ (12)

APS Consolidated

	Six Months Ended June 30,		
	2026	2025	Net Change
Net cash flow provided by operating activities	$ 688	$ 698	$ (10)
Net cash flow used for investing activities	(1,188)	(1,248)	60
Net cash flow provided by financing activities	503	561	(58)
Net increase in cash and cash equivalents	$ 3	$ 11	$ (8)

Operating Cash Flows

Six-month period ended June 30, 2026 compared with six-month period ended June 30, 2025. Pinnacle West's consolidated net cash provided by operating activities was $629 million in 2026 compared to $663 million in 2025, a decrease of $34 million in net cash provided, primarily due to $68 million in higher payments for fuel and purchased power costs, $35 million in higher interest paid on debt, net of amounts capitalized, and $14 million higher payments for other taxes paid; partially offset by $61 million higher cash receipts from electric revenues and $22 million in higher working capital, net. The difference between APS's and Pinnacle West's net cash provided by operating activities primarily relates to APS's lower interest paid on debt, net of amounts capitalized, and other changes in working capital.

Retirement plans and other postretirement benefits. Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. Pinnacle West also sponsors other postretirement benefit plans for the employees of Pinnacle West and its 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. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. The expected minimum required cash contributions for the pension plan are zero for the next three years. However, while we do not expect to make any voluntary cash contributions in 2026, we are evaluating whether to make voluntary contributions in 2027 and 2028. The amounts of voluntary contributions, if any, will be determined as we continue to evaluate and assess our ongoing contribution strategy. Regarding contributions to our other postretirement benefit plan, we have not made a contribution year-to-date in 2026 and do not expect to make any contributions in 2026, 2027 or 2028. We continually monitor financial market volatility and its impact on our retirement plans and other postretirement benefits, but we believe our liability driven investment strategy helps to minimize the impact of market volatility on our plan's funded status.

Investing Cash Flows

Six-month period ended June 30, 2026 compared with six-month period ended June 30, 2025. Pinnacle West's consolidated net cash used for investing activities was $1,200 million in 2026 compared to $1,253 million in 2025, a decrease of $53 million of cash used primarily related to a $70 million increase in contributions in aid of construction; partially offset by a $25 million increase in capital expenditures. See "Capital Expenditures" below for additional details.

Capital Expenditures. The following table summarizes the estimated capital expenditures for the next three years (dollars in millions):

Capital Expenditures

	Estimated for the Year Ending December 31,		
	2026	**2027**	**2028**
APS			
Generation:			
Gas and Other Generation	$ 635	$ 550	$ 490
Nuclear Generation	170	185	215
Renewables and Energy Storage	20	5	5
Distribution	765	795	750
Transmission	550	695	860
Other	460	420	380
Total APS	$ 2,600	$ 2,650	$ 2,700

The estimated capital expenditures presented above do not include amounts related to the Cholla gas conversion project, which is currently expected to cost up to approximately $440 million. In addition, projected capital expenditures for entities other than APS are not included, as such amounts are expected to be immaterial.

Generation capital expenditures are comprised of various additions and improvements to APS's resources, including nuclear plants, renewables and energy storage, additions and improvements to existing fossil fuel plants, as well as planned investments in new natural gas facilities. We are monitoring the status of environmental matters, which, depending on their final outcome, could require modification to our planned environmental expenditures.

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

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

Financing Cash Flows and Liquidity

Six-month period ended June 30, 2026 compared with six-month period ended June 30, 2025. Pinnacle West's consolidated net cash provided by financing activities was $574 million in 2026 compared to $605 million in 2025, a decrease of $31 million in net cash provided primarily due to a net decrease of $775 million in short-term borrowings; partially offset by a $450 million decrease in long-term debt repayments and a $297 million increase in long-term borrowings.

APS's consolidated net cash provided by financing activities was $503 million in 2026 compared to $561 million in 2025, a decrease of $58 million in net cash provided primarily due to a net decrease of $753 million in short-term borrowings and $200 million in lower equity infusions from the parent; partially offset by a $595 million increase in long-term borrowings and a $300 million decrease in long-term debt repayments.

Significant Financing Activities. On June 24, 2026, the Pinnacle West Board of Directors declared a dividend of $0.91 per share of common stock, payable on September 1, 2026, to shareholders of record on August 3, 2026.

On June 5, 2026, Pinnacle West contributed $100 million into APS in the form of an equity infusion. APS used this contribution to pay down short-term indebtedness consisting of commercial paper.

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. See Note 6 for more information on available credit facilities.

Equity Offerings. Pinnacle West entered into certain equity forward sale agreements in February 2024 and has an ATM Program under which Pinnacle West may offer and sell Pinnacle West common stock and enter into equity forward sale agreements from time to time, subject to market conditions and other factors. These agreements may be settled at Pinnacle West's discretion by issuing shares of Pinnacle West common stock and receiving cash, if any, at the then-applicable forward sales price. See Note 13. The following table summarizes the activity relating to these forward sale agreements and the ATM Program as of June 30, 2026 (dollars in thousands, except price per share):

Forward Sale Agreements	Number of Shares		Forward Sales Price Per Share			Aggregate Value	
February 2024 Forward Sale Agreements							
Initial Price	11,240,601		$	64.51	(a)	$	725,131
Settlements							
December 23, 2024	5,377,115	(b)	$	64.17		$	345,049 (c)
September 4, 2025	243,186	(b)	$	63.12		$	15,350 (c)
December 18, 2025	1,193,950	(b)	$	62.82		$	75,004 (c)
ATM Program							
Initial Price (e)	8,306,132		$	97.38	(a) (d)	$	808,887

(a) Subject to certain adjustments.
(b) Physical delivery.
(c) Proceeds recorded in common equity on the Condensed Consolidated Balance Sheets.
(d) Weighted-average price for the total ATM Program.
(e) Does not include one forward sale agreement, whose effective date was July 6, 2026, relating to a total of $84 million, on a gross basis, of common stock, with a maturity date of July 3, 2028.

Other Financing Matters. See Note 10 for information related to the change in our margin and collateral accounts.

Debt Provisions

Pinnacle West's and APS's debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with these covenants. For both Pinnacle West and APS, these covenants require that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. As of June 30, 2026, the ratio was approximately 62% for Pinnacle West and 51% 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.

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

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

Credit Ratings

The ratings of securities of Pinnacle West and APS as of July 31, 2026, are shown below. We are disclosing these credit ratings to enhance understanding of our cost of short-term and long-term capital and our ability to access the markets for liquidity and long-term debt. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS's securities and/or result in an increase in the cost of, or limit access to, capital. Such revisions may also result in substantial additional cash or other collateral requirements related to certain derivative instruments, insurance policies, natural gas transportation, fuel supply, and other energy-related contracts. At this time, we believe we have sufficient available liquidity resources to respond to a potential downward revision to our credit ratings.

	Moody's	Standard & Poor's	Fitch
Pinnacle West			
Corporate credit rating	Baa2	BBB+	BBB
Senior unsecured	Baa2	BBB	BBB
Commercial paper	P-2	A-2	F3
Outlook	Stable	Stable	Stable
APS			
Corporate credit rating	Baa1	BBB+	BBB+
Senior unsecured	Baa1	BBB+	A-
Commercial paper	P-2	A-2	F2
Outlook	Stable	Stable	Stable

Contractual Obligations

Pinnacle West's contractual obligations have not materially changed during the six months ended June 30, 2026 as compared to the 2025 Form 10-K, except as disclosed in Note 6 - "Debt and Liquidity Matters" and Note 11 - "Commitments and Contingencies" to the Combined Notes to condensed consolidated financial statements included in this report.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In preparing the financial statements in accordance with GAAP, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. There have been no changes to our critical accounting policies and estimates since our 2025 Form 10-K. See "Critical Accounting Policies and Estimates" in Item 7 of the 2025 Form 10-K for further details about our critical accounting policies and estimates.

OTHER ACCOUNTING MATTERS

See Note 3 for information relating to the following new accounting standards pending adoption:

- ASU 2024-03, Income Statement Reporting: Expense Disaggregation Disclosures, effective for us on December 31, 2027, with early adoption permitted.
- ASU 2025-06, Intangibles—Goodwill and Other—Internal-Use Software: Targeted Improvements to the Accounting for Internal-Use Software, effective for us on January 1, 2028, with early adoption permitted.
- ASU 2025-09, Derivatives and Hedging: Hedge Accounting Improvements, effective for us on January 1, 2027, with early adoption permitted.
- ASU 2025-10, Government Grants: Accounting for Government Grants Received by Business Entities, effective for us on January 1, 2029, with early adoption permitted.
- ASU 2026-02, Environmental Credits and Environmental Credit Obligations, effective for us on January 1, 2028, with early adoption permitted.

MARKET AND CREDIT RISKS

Market Risks

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

Interest Rate and Equity Risk

We have exposure to changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and the market value of fixed income securities held by our nuclear decommissioning trust, other special use funds (see Notes 14 and 15), 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, coal reclamation, and benefit plan costs are recovered in regulated electricity prices.

Commodity Price Risk

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

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

	Six Months Ended June 30, 2026	Six Months Ended June 30, 2025
Balance at beginning of period	$ (26)	$ (42)
Decrease (increase) in regulatory asset	(53)	59
Balance at end of period	$ (79)	$ 17

The table below shows the fair value of maturities of our energy derivative contracts (dollars in millions) as of June 30, 2026, 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 2025 Form 10-K for more discussion of our valuation methods.

Source of Fair Value	2026	2027	2028	2029	2030	Total Fair Value
Observable prices provided by other external sources	$ (23)	$ (20)	$ (4)	$ 1	$ —	$ (46)
Prices based on unobservable inputs	(32)	—	—	(1)	—	(33)
Total by maturity	$ (55)	$ (20)	$ (4)	$ —	$ —	$ (79)

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

	June 30, 2026 Gain (Loss)		December 31, 2025 Gain (Loss)	
	Price Up 10%	Price Down 10%	Price Up 10%	Price Down 10%
Mark-to-market changes reported in:				
Regulatory asset (liability) (a)				
Electricity	$ 2	$ (2)	$ 3	$ (3)
Natural gas	50	(50)	58	(58)
Total	$ 52	$ (52)	$ 61	$ (61)

(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 10 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”), is recorded, processed, summarized and reported, within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to a company’s management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Pinnacle West’s management, with the participation of Pinnacle West’s Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of Pinnacle West’s disclosure controls and procedures as of June 30, 2026. Based on that evaluation, Pinnacle West’s Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, Pinnacle West’s disclosure controls and procedures were effective.

APS’s management, with the participation of APS’s Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of APS’s disclosure controls and procedures as of June 30, 2026. 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 Exchange Act Rule 13a-15(f)) refers to the process of a company that is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

No change in Pinnacle West’s or APS’s internal control over financial reporting occurred during the fiscal quarter ended June 30, 2026 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 2025 Form 10-K with regard to pending or threatened litigation and other matters.

See Note 7 for ACC and FERC-related matters.

See Note 11 for information regarding environmental matters, Superfund-related matters and other disputes and proceedings.

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 2025 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 2025 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

Ozone National Ambient Air Quality Standards

On October 1, 2015, EPA finalized revisions to the primary ground-level ozone NAAQS at a level of 70 parts per billion (“ppb”). As ozone standards become more stringent, our fossil generation units will come under increasing pressure to reduce emissions of NOx and volatile organic compounds, and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas. EPA was expected to designate attainment and nonattainment areas relative to the new 70 ppb standard by October 1, 2017. While EPA took action designating attainment and unclassifiable areas on November 6, 2017, the Agency’s final action designating non-attainment areas was not issued until April 30, 2018. At that time, EPA designated the geographic areas containing Yuma and Phoenix, Arizona as in non-attainment with the 2015 70 ppb ozone NAAQS. The vast majority of APS’s natural gas-fired EGUs are located in these jurisdictions. Areas of Arizona and the Navajo Nation where the remainder of APS’s fossil-fuel fired electric generating unit fleet is located were designated as in attainment. On December 23, 2020, EPA issued a final regulation retaining the current primary NAAQS for ozone, following a required scientific review process. On October 7, 2022, EPA took final action designating Maricopa County, which includes the Phoenix, Arizona metropolitan area, as “moderate” for non-attainment with the governing ozone NAAQS, which provided for an August 3, 2024 attainment “deadline” by which the area would be automatically designated as in “serious” non-attainment unless it achieved the 2015 ozone NAAQS. On November 18, 2025, EPA redesignated the geographic area containing Yuma into attainment for the 2015 Ozone NAAQS.

On November 19, 2025, EPA issued a proposed rule determining that the Phoenix-Mesa area would have met the 2015 ozone NAAQS standard by its August 3, 2024 “Moderate” attainment date, “but for” emissions emanating from outside of the United States. This proposal was subsequently finalized on March 23, 2026. As a result, facilities applying for new or modified permits in Maricopa County can continue under the moderate nonattainment NOx threshold, rather than being subject to more restrictive serious nonattainment limitations. On May 22, 2026, a coalition of Environmental NGOs, including Sierra Club, Center for Biological Diversity, Natural Resources Defense Council, and Public Employees for Environmental Responsibility, filed a petition for review in the Ninth Circuit Court of Appeals challenging the EPA’s final action. APS will continue to monitor this proceeding. At this time, APS is unable to predict the outcome of this litigation.

Rule 10b5-1 Trading Plans

During the fiscal quarter ended June 30, 2026, none of our directors or executive officers adopted or terminated any “Rule 10b5-1 trading arrangement” or “non-Rule 10b5-1 trading arrangement” as each term is defined in Item 408 of Regulation S-K.

ITEM 6. EXHIBITS

(a) Exhibits

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit	Date Filed
3.1	Pinnacle West	Articles of Incorporation, restated as of May 22, 2025	3.1 to Pinnacle West/APS June 30, 2025 Form 10-Q Report	8/6/2025
3.2	Pinnacle West	Bylaws, amended as of February 19, 2020	3.1 to Pinnacle West/APS Form 8-K Report filed February 25, 2020	2/25/2020
3.3	APS	Articles of Incorporation, restated as of May 16, 2012	3.3 to Pinnacle West/APS June 30, 2025 Form 10-Q Report	8/6/2025
3.4	APS	Bylaws, amended as of December 16, 2008	3.4 to Pinnacle West/APS December 31, 2008 Form 10-K Report	2/20/2009
4.1	Pinnacle West APS	Seventh Supplemental Indenture dated as of June 5, 2026	4.1 to Pinnacle West June 1, 2026 Form 8-K Report	6/5/2026
10.1	Pinnacle West APS	Discretionary Credit Award Agreement, dated June 23, 2026, by and between APS and Adam Heflin	10.1 to Pinnacle West/APS June 23, 2026 Form 8-K Report	6/29/2026
31.1	Pinnacle West	Certificate of Theodore N. Geisler, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act of 1934, as amended		
31.2	Pinnacle West	Certificate of Andrew Cooper, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act of 1934, as amended		
31.3	APS	Certificate of Theodore N. Geisler, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act of 1934, as amended		
31.4	APS	Certificate of Andrew Cooper, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act of 1934, as amended		
32.1[(a)]	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[a]	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	Inline 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	Inline XBRL Taxonomy Extension Schema Document
101.CAL	Pinnacle West APS	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	Pinnacle West APS	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE	Pinnacle West APS	Inline XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	Pinnacle West APS	Inline XBRL Taxonomy Definition Linkbase Document
104	Pinnacle West APS	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

[a] Furnished herewith as an exhibit.

SIGNATURES

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

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Dated:	August 4, 2026	By:	/s/ Andrew Cooper
			Andrew Cooper Senior Vice President and Chief Financial Officer (Principal Financial Officer and Officer Duly Authorized to sign this Report)

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Dated:	August 4, 2026	By:	/s/ Andrew Cooper
			Andrew Cooper Senior Vice President and Chief Financial Officer (Principal Financial Officer and Officer Duly Authorized to sign this Report)

Exhibit 31.1

CERTIFICATION

I, Theodore N. Geisler, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2026

/s/ Theodore N. Geisler

Theodore N. Geisler
Chairman of the Board, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Andrew Cooper, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2026

/s/ Andrew Cooper

Andrew Cooper

Senior Vice President and Chief Financial Officer

Exhibit 31.3

CERTIFICATION

I, Theodore N. Geisler, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Arizona Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2026

/s/ Theodore N. Geisler

Theodore N. Geisler
Chairman of the Board, President and Chief Executive Officer

Exhibit 31.4

CERTIFICATION

I, Andrew Cooper, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Arizona Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2026

/s/ Andrew Cooper

Andrew Cooper

Senior Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION
OF
CHIEF EXECUTIVE OFFICER
AND
CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Theodore N. Geisler, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation for the quarter ended June 30, 2026 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West Capital Corporation.

Date: August 4, 2026

/s/ Theodore N. Geisler
Theodore N. Geisler
Chairman of the Board, President and Chief Executive Officer

I, Andrew Cooper, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation for the quarter ended June 30, 2026 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West Capital Corporation.

Date: August 4, 2026

/s/ Andrew Cooper
Andrew Cooper
Senior Vice President and Chief Financial Officer

Exhibit 32.2

CERTIFICATION
OF
CHIEF EXECUTIVE OFFICER
AND
CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Theodore N. Geisler, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Quarterly Report on Form 10-Q of Arizona Public Service Company for the quarter ended June 30, 2026 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Arizona Public Service Company.

Date: August 4, 2026

/s/ Theodore N. Geisler
Theodore N. Geisler
Chairman of the Board, President and Chief Executive Officer

I, Andrew Cooper, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Quarterly Report on Form 10-Q of Arizona Public Service Company for the quarter ended June 30, 2026 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Arizona Public Service Company.

Date: August 4, 2026

/s/ Andrew Cooper
Andrew Cooper
Senior Vice President and Chief Financial Officer