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, 2025

OR

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

For the transition period from to

Commission File Number	Exact name of each registrant as specified in its charter; State 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
Common Stock, no par value	PNW	New York Stock Exchange

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

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

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

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

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

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

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

PINNACLE WEST CAPITAL CORPORATION	Number of shares of common stock, no par value, outstanding as of July 31, 2025:	119,427,244
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of July 31, 2025:	71,264,947

Arizona Public Service Company meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this form with the reduced disclosure format allowed under that General Instruction.

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This combined 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.

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, 2024 ("2024 Form 10-K"), and Part II, Item 1A of this report, these factors include, but are not limited to:

- uncertainties associated with the current and future economic environment, including economic growth rates, labor market conditions, tariffs, inflation, supply chain delays, increased expenses, volatile capital markets, or other unpredictable effects;
- current and future economic conditions in Arizona, such as the housing market and overall business and regulatory environment;
- our ability to manage capital expenditures and operations and maintenance costs while maintaining reliability and customer service levels;
- 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;
- 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), the effects of energy conservation measures and distributed generation, and technological advancements;
- 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;
- power plant and transmission system performance and outages;
- competition in retail and wholesale power markets;
- regulatory and judicial decisions, developments, and proceedings;
- new legislation, ballot initiatives, and regulation or interpretations of existing legislation or regulations, including those relating to tax, environmental requirements, regulatory and energy policy, nuclear plant operations, and potential deregulation of retail electric markets;
- fuel and water supply availability;
- our ability to achieve timely and adequate rate recovery of our costs through our rates and adjustor recovery mechanisms, including returns on and of debt and equity capital investment;
- the ability of APS to meet renewable energy and energy efficiency mandates and recover related costs;
- the ability of APS to achieve its clean energy goal to be carbon-neutral by 2050 and, if this goal is achieved, the impact of such achievement on APS, its customers, and its business, financial condition, and results of operations;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- the development of new technologies which may affect electric sales or delivery, including as a result of delays in the development and application of new technologies;
- 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;
- environmental, economic, and other concerns surrounding coal-fired generation, including regulation of greenhouse gas emissions ("GHG");
- volatile fuel and purchased power costs;
- 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;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;

- potential shortfalls in insurance coverage;
- new accounting requirements or new interpretations of existing requirements;
- generation, transmission, and distribution facilities and system conditions and operating costs;
- our ability to meet the anticipated future need for additional generation and associated transmission facilities in our region;
- the willingness or ability of counterparties, power plant participants, and power plant landowners to meet contractual or other obligations or extend the rights for continued power plant operations; and
- restrictions on dividends or other provisions in our credit agreements and Arizona Corporation Commission ("ACC") orders.

These and other factors are discussed in the Risk Factors described in Part I, Item 1A of our 2024 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,	
	2025	2024	2025	2024
OPERATING REVENUES (Note 4)	$1,358,751	$1,308,994	$2,391,031	$2,260,706
OPERATING EXPENSES				
Fuel and purchased power	477,008	437,172	857,079	795,036
Operations and maintenance	286,605	272,266	586,714	529,844
Depreciation and amortization	228,893	225,017	463,833	435,311
Taxes other than income taxes	57,651	58,651	117,005	117,815
Other expense	1,042	2,141	1,626	2,161
Total	1,051,199	995,247	2,026,257	1,880,167
OPERATING INCOME	307,552	313,747	364,774	380,539
OTHER INCOME (DEDUCTIONS)				
Allowance for equity funds used during construction	14,767	8,910	28,016	19,202
Pension and other postretirement non-service credits, net (Note 7)	3,692	12,877	6,650	24,445
Other income (Note 11)	12,104	5,885	29,565	36,492
Other expense (Note 11)	(4,259)	(3,032)	(6,829)	(10,599)
Total	26,304	24,640	57,402	69,540
INTEREST EXPENSE				
Interest charges	113,527	108,891	218,470	208,665
Allowance for borrowed funds used during construction	(11,559)	(11,036)	(21,661)	(24,177)
Total	101,968	97,855	196,809	184,488
Income Before Income Taxes	231,888	240,532	225,367	265,591
Income taxes	35,018	32,421	28,835	36,312
Net Income	196,870	208,111	196,532	229,279
Less: Net income attributable to noncontrolling interests (Note 8)	4,306	4,306	8,612	8,612
Net Income Attributable to Common Shareholders	$ 192,564	$ 203,805	$ 187,920	$ 220,667
Weighted-average common shares outstanding - basic	119,517	113,695	119,555	113,658
Weighted-average common shares outstanding - diluted	121,865	115,803	121,813	115,015
Earnings Per Weighted-Average Common Share Outstanding				
Net income attributable to common shareholders - basic	$ 1.61	$ 1.79	$ 1.57	$ 1.94
Net income attributable to common shareholders - diluted	$ 1.58	$ 1.76	$ 1.54	$ 1.92

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,	
	2025	2024	2025	2024
NET INCOME	$ 196,870	$ 208,111	$ 196,532	$ 229,279
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX				
Derivative instruments:				
Derivative instruments net unrealized gain (loss), net of tax benefit (expense) of $(18), $131, $(18) and $131	(294)	(399)	56	(399)
Pension and other postretirement benefit activity, net of tax benefit (expense) of $69, $103, $(95) and $(82)	(53)	(313)	445	249
Total other comprehensive income (loss)	(347)	(712)	501	(150)
COMPREHENSIVE INCOME	196,523	207,399	197,033	229,129
Less: Comprehensive income attributable to noncontrolling interests	4,306	4,306	8,612	8,612
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 192,217	$ 203,093	$ 188,421	$ 220,517

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, 2025	December 31, 2024
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 18,841	$ 3,838
Customer and other receivables	569,656	525,608
Accrued unbilled revenues (Note 4)	272,327	176,903
Allowance for doubtful accounts (Note 4)	(17,449)	(24,849)
Materials and supplies (at average cost)	509,269	469,022
Fossil fuel (at average cost)	17,670	32,420
Assets from risk management activities (Note 9)	10,903	10,578
Deferred fuel and purchased power regulatory asset (Note 6)	182,412	287,597
Other regulatory assets (Note 6)	121,436	133,372
Other current assets	102,843	74,915
Total current assets	1,787,908	1,689,404
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 13 and 14)	1,337,858	1,282,845
Other special use funds (Notes 13 and 14)	423,332	408,357
Assets from risk management activities (Note 9)	34,203	5,980
Other assets	140,619	115,095
Total investments and other assets	1,936,012	1,812,277
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	25,895,037	25,860,950
Accumulated depreciation and amortization	(8,690,747)	(9,027,426)
Net	17,204,290	16,833,524
Construction work in progress	2,087,779	1,592,659
Palo Verde sale leaseback, net of accumulated depreciation (Note 8)	80,622	82,556
Intangible assets, net of accumulated amortization	569,047	591,310
Nuclear fuel, net of accumulated amortization	120,267	97,850
Total property, plant and equipment	20,062,005	19,197,899
DEFERRED DEBITS		
Regulatory assets (Note 6)	1,357,382	1,389,489
Operating lease right-of-use assets (Note 16)	3,638,906	1,605,463
Assets for pension and other postretirement benefits (Note 7)	364,229	342,102
Other	88,739	66,126
Total deferred debits	5,449,256	3,403,180
TOTAL ASSETS	$ 29,235,181	$ 26,102,760

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, 2025	December 31, 2024
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 668,664	$ 485,426
Accrued taxes	205,460	175,863
Accrued interest	84,760	81,799
Common dividends payable	106,869	106,592
Short-term borrowings (Note 5)	1,405,000	568,450
Current maturities of long-term debt (Note 5)	350,000	800,000
Customer deposits	53,272	44,345
Liabilities from risk management activities (Note 9)	25,692	52,340
Liabilities for asset retirements	41,226	50,009
Operating lease liabilities (Note 16)	191,628	100,367
Regulatory liabilities (Note 6)	182,458	206,955
Other current liabilities	112,213	171,651
Total current liabilities	3,427,242	2,843,797
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 5)	8,507,002	8,058,648
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,465,821	2,444,473
Regulatory liabilities (Note 6)	1,912,279	1,855,278
Liabilities for asset retirements	1,123,521	1,096,577
Liabilities for pension benefits (Note 7)	147,929	139,317
Liabilities from risk management activities (Note 9)	7,144	9,446
Customer advances	580,656	569,343
Coal mine reclamation	155,600	171,483
Deferred investment tax credit	246,189	249,490
Unrecognized tax benefits	45,815	44,233
Operating lease liabilities (Note 16)	3,550,894	1,520,877
Other	237,149	242,320
Total deferred credits and other	10,472,997	8,342,837
COMMITMENTS AND CONTINGENCIES (Note 10)		
EQUITY		
Common stock, no par value; 300,000,000 and 150,000,000 shares authorized at respective dates, 119,472,939 and 119,143,782 shares issued at respective dates	3,119,404	3,121,617
Treasury stock at cost; 46,968 and 46,968 shares at respective dates	(3,323)	(3,323)
Total common stock	3,116,081	3,118,294
Retained earnings	3,641,148	3,666,959
Accumulated other comprehensive loss (Note 15)	(30,441)	(30,942)
Total shareholders' equity	6,726,788	6,754,311
Noncontrolling interests (Note 8)	101,152	103,167
Total equity	6,827,940	6,857,478
TOTAL LIABILITIES AND EQUITY	$ 29,235,181	$ 26,102,760

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, 2025	Six Months Ended June 30, 2024
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 196,532	$ 229,279
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on sale relating to BCE	—	(22,988)
Depreciation and amortization including nuclear fuel	492,225	465,546
Deferred fuel and purchased power	(95,850)	(64,220)
Deferred fuel and purchased power amortization	201,035	204,748
Allowance for equity funds used during construction	(28,016)	(19,202)
Deferred income taxes	1,439	339
Deferred investment tax credit	(3,301)	(4,082)
Stock compensation	12,356	10,622
Changes in current assets and liabilities:		
Customer and other receivables	(47,587)	(57,802)
Accrued unbilled revenues	(95,424)	(147,165)
Materials, supplies and fossil fuel	(25,497)	(55,498)
Income tax receivable	—	332
Other current assets	(41,851)	(53,124)
Accounts payable	127,970	99,513
Accrued taxes	29,597	34,381
Other current liabilities	1,182	(11,061)
Change in long-term regulatory assets	38,992	18,183
Change in long-term regulatory liabilities	44,860	(4,637)
Change in other long-term assets	(140,504)	(43,489)
Change in operating lease assets	138,439	19,785
Change in other long-term liabilities	(56,639)	(45,456)
Change in operating lease liabilities	(86,632)	(16,866)
Net cash provided by operating activities	663,326	537,138
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(1,332,068)	(1,051,725)
Contributions in aid of construction	107,716	144,329
Proceeds from sale relating to BCE	—	47,778
Allowance for borrowed funds used during construction	(21,661)	(24,177)
Proceeds from nuclear decommissioning trusts sales and other special use funds	919,644	772,375
Investment in nuclear decommissioning trusts and other special use funds	(920,785)	(772,359)
Other	(6,178)	(3,335)
Net cash used for investing activities	(1,253,332)	(887,114)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	795,404	1,313,229
Repayment of long-term debt	(800,000)	(675,000)
Short-term borrowing and (repayments) - net	436,549	(78,050)
Short-term debt borrowings under term loan facility	400,000	350,000
Short-term debt repayments under term loan facility	—	(350,000)
Dividends paid on common stock	(210,150)	(196,296)
Common stock equity issuance and (purchases) - net	(6,166)	(4,227)
Capital activities by noncontrolling interests	(10,628)	(10,628)
Net cash provided by financing activities	605,009	349,028
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	15,003	(948)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	3,838	4,955
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 18,841	$ 4,007

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, 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

	Three Months Ended June 30, 2024							
	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, March 31, 2024	113,686,849	$2,757,506	(128,234)	$ (9,073)	$ 3,483,178	$ (32,582)	$ 111,504	$ 6,310,533
Net income		—		—	203,805	—	4,306	208,111
Other comprehensive loss		—		—	—	(712)	—	(712)
Dividends on common stock ($1.76 per share)		—			(199,868)	—	—	(199,868)
Issuance of common stock (a)	24,914	7,005		—	—	—	—	7,005
Reissuance of treasury stock for stock-based compensation and other		—	26,593	1,882	—	—	—	1,882
Capital activities by noncontrolling interests		—		—	—	—	(10,628)	(10,628)
Other		—		—	(2)	—	1	(1)
Balance, June 30, 2024	113,711,763	$2,764,511	(101,641)	$ (7,191)	$ 3,487,113	$ (33,294)	$ 105,183	$ 6,316,322

(a) See Note 12 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, 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

	Six Months Ended June 30, 2024							
	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, December 31, 2023	113,537,689	$2,752,676	(113,272)	$ (8,185)	$ 3,466,317	$ (33,144)	$ 107,198	$ 6,284,862
Net income		—		—	220,667	—	8,612	229,279
Other comprehensive loss		—		—	—	(150)	—	(150)
Dividends on common stock ($1.76 per share)		—		—	(199,868)	—	—	(199,868)
Issuance of common stock (a)	174,074	11,835		—	—	—	—	11,835
Purchase of treasury stock (b)		—	(71,008)	(4,907)	—	—	—	(4,907)
Reissuance of treasury stock for stock-based compensation and other		—	82,639	5,900	—	—	—	5,900
Capital activities by noncontrolling interests		—		—	—	—	(10,628)	(10,628)
Other		—		1	(3)	—	1	(1)
Balance, June 30, 2024	113,711,763	$2,764,511	(101,641)	$ (7,191)	$ 3,487,113	$ (33,294)	$ 105,183	$ 6,316,322

(a) See Note 12 for information related to our equity forward sale agreements.
(b) Primarily represents shares of common stock withheld from certain stock awards for tax purposes.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
OPERATING REVENUES (Note 4)	$1,358,751	$1,308,994	$2,391,031	$2,260,706
OPERATING EXPENSES				
Fuel and purchased power	477,008	437,172	857,079	795,036
Operations and maintenance	285,211	272,674	581,862	526,267
Depreciation and amortization	228,876	224,996	463,799	435,269
Taxes other than income taxes	57,642	58,666	116,978	117,744
Other expense	1,042	2,141	1,626	2,161
Total	1,049,779	995,649	2,021,344	1,876,477
OPERATING INCOME	308,972	313,345	369,687	384,229
OTHER INCOME (DEDUCTIONS)				
Allowance for equity funds used during construction	14,767	8,910	28,016	19,202
Pension and other postretirement non-service credits, net (Note 7)	3,916	13,068	7,116	24,841
Other income (Note 11)	3,674	4,591	9,396	11,446
Other expense (Note 11)	(3,890)	(2,894)	(6,223)	(5,788)
Total	18,467	23,675	38,305	49,701
INTEREST EXPENSE				
Interest charges	91,915	93,294	180,686	180,273
Allowance for borrowed funds used during construction	(11,559)	(11,036)	(21,661)	(24,177)
Total	80,356	82,258	159,025	156,096
Income Before Income Taxes	247,083	254,762	248,967	277,834
Income taxes	38,679	38,655	35,978	42,304
Net Income	208,404	216,107	212,989	235,530
Less: Net income attributable to noncontrolling interests (Note 8)	4,306	4,306	8,612	8,612
Net Income Attributable to Common Shareholder	$ 204,098	$ 211,801	$ 204,377	$ 226,918

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,	
	2025	2024	2025	2024
NET INCOME	$ 208,404	$ 216,107	$ 212,989	$ 235,530
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX				
Pension and other postretirement benefits activity, net of tax benefit (expense) of $44, $101, $(89) and $(60)	(136)	(307)	270	183
Total other comprehensive income (loss)	(136)	(307)	270	183
COMPREHENSIVE INCOME	208,268	215,800	213,259	235,713
Less: Comprehensive income attributable to noncontrolling interests	4,306	4,306	8,612	8,612
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 203,962	$ 211,494	$ 204,647	$ 227,101

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, 2025	December 31, 2024
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	$ 25,894,155	$ 25,860,068
Accumulated depreciation and amortization	(8,689,865)	(9,026,544)
Net	17,204,290	16,833,524
Construction work in progress	2,087,779	1,592,659
Palo Verde sale leaseback, net of accumulated depreciation (Note 8)	80,622	82,556
Intangible assets, net of accumulated amortization	568,892	591,154
Nuclear fuel, net of accumulated amortization	120,267	97,850
Total property, plant and equipment	20,061,850	19,197,743
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trusts (Notes 13 and 14)	1,337,858	1,282,845
Other special use funds (Notes 13 and 14)	384,792	374,156
Assets from risk management activities (Note 9)	34,203	5,980
Other assets	51,495	49,673
Total investments and other assets	1,808,348	1,712,654
CURRENT ASSETS		
Cash and cash equivalents	14,480	3,815
Customer and other receivables	566,896	522,886
Accrued unbilled revenues (Note 4)	272,327	176,903
Allowance for doubtful accounts (Note 4)	(17,449)	(24,849)
Materials and supplies (at average cost)	509,269	469,022
Fossil fuel (at average cost)	17,670	32,420
Income tax receivable	42	5,463
Assets from risk management activities (Note 9)	10,903	10,578
Deferred fuel and purchased power regulatory asset (Note 6)	182,412	287,597
Other regulatory assets (Note 6)	121,436	133,372
Other current assets	93,685	65,754
Total current assets	1,771,671	1,682,961
DEFERRED DEBITS		
Regulatory assets (Note 6)	1,357,382	1,389,489
Operating lease right-of-use assets (Note 16)	3,637,830	1,604,324
Assets for pension and other postretirement benefits (Note 7)	357,444	335,458
Other	88,107	65,606
Total deferred debits	5,440,763	3,394,877
TOTAL ASSETS	$ 29,082,632	$ 25,988,235

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, 2025	December 31, 2024
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	4,416,696	4,116,696
Retained earnings	3,983,202	3,992,423
Accumulated other comprehensive loss (Note 15)	(13,846)	(14,116)
Total shareholder equity	8,564,214	8,273,165
Noncontrolling interests (Note 8)	101,152	103,167
Total equity	8,665,366	8,376,332
Long-term debt less current maturities (Note 5)	7,193,037	7,190,878
Total capitalization	15,858,403	15,567,210
CURRENT LIABILITIES		
Short-term borrowings (Note 5)	1,125,400	339,900
Current maturities of long-term debt (Note 5)	—	300,000
Accounts payable	662,610	481,955
Accrued taxes	226,603	181,698
Accrued interest	77,586	79,308
Common dividends payable	106,900	107,200
Customer deposits	53,272	44,345
Liabilities from risk management activities (Note 9)	25,692	52,340
Liabilities for asset retirements	41,226	50,009
Operating lease liabilities (Note 16)	191,484	100,229
Regulatory liabilities (Note 6)	182,458	206,955
Other current liabilities	108,544	177,019
Total current liabilities	2,801,775	2,120,958
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,431,120	2,419,937
Regulatory liabilities (Note 6)	1,912,279	1,855,278
Liabilities for asset retirements	1,123,521	1,096,577
Liabilities for pension benefits (Note 7)	144,581	134,855
Liabilities from risk management activities (Note 9)	7,144	9,446
Customer advances	580,656	569,343
Coal mine reclamation	155,600	171,483
Deferred investment tax credit	246,189	249,490
Unrecognized tax benefits	50,307	48,725
Operating lease liabilities (Note 16)	3,549,774	1,519,683
Other	221,283	225,250
Total deferred credits and other	10,422,454	8,300,067
COMMITMENTS AND CONTINGENCIES (Note 10)		
TOTAL LIABILITIES AND EQUITY	$ 29,082,632	$ 25,988,235

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, 2025	Six Months Ended June 30, 2024
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 212,989	$ 235,530
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	492,191	465,504
Deferred fuel and purchased power	(95,850)	(64,220)
Deferred fuel and purchased power amortization	201,035	204,748
Allowance for equity funds used during construction	(28,016)	(19,202)
Deferred income taxes	(8,702)	(257)
Deferred investment tax credit	(3,301)	(4,082)
Changes in current assets and liabilities:		
Customer and other receivables	(47,549)	(52,990)
Accrued unbilled revenues	(95,424)	(147,165)
Materials, supplies and fossil fuel	(25,497)	(55,498)
Income tax receivable	5,421	—
Other current assets	(41,854)	(21,506)
Accounts payable	125,387	98,992
Accrued taxes	44,905	60,314
Other current liabilities	(12,544)	(27,078)
Change in long-term regulatory assets	38,992	18,183
Change in long-term regulatory liabilities	44,860	(4,637)
Change in other long-term assets	(117,624)	(69,075)
Change in operating lease assets	138,376	19,659
Change in other long-term liabilities	(43,634)	(46,992)
Change in operating lease liabilities	(86,558)	(16,798)
Net cash provided by operating activities	697,603	573,430
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(1,332,068)	(1,051,727)
Contributions in aid of construction	107,716	144,329
Allowance for borrowed funds used during construction	(21,661)	(24,177)
Proceeds from nuclear decommissioning trusts sales and other special use funds	869,190	772,375
Investment in nuclear decommissioning trusts and other special use funds	(870,331)	(772,359)
Other	(756)	(919)
Net cash used for investing activities	(1,247,910)	(932,478)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	—	445,842
Repayment of long-term debt	(300,000)	(250,000)
Short-term borrowing and (repayments) - net	385,500	(77,150)
Short-term debt borrowings under term loan facility	400,000	350,000
Short-term debt repayments under term loan facility	—	(350,000)
Equity infusion from Pinnacle West	300,000	450,000
Dividends paid on common stock	(213,900)	(199,700)
Capital activities by noncontrolling interests	(10,628)	(10,628)
Net cash provided by financing activities	560,972	358,364
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	10,665	(684)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	3,815	4,549
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 14,480	$ 3,865

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, 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

	Three Months Ended June 30, 2024						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, March 31, 2024	71,264,947	$ 178,162	$ 3,321,696	$ 3,774,414	$ (16,729)	$ 111,504	$ 7,369,047
Equity infusion from Pinnacle West		—	450,000	—	—	—	450,000
Net income		—	—	211,801	—	4,306	216,107
Other comprehensive loss		—	—	—	(307)	—	(307)
Dividends on common stock		—	—	(199,900)	—	—	(199,900)
Capital activities by noncontrolling interests		—	—	—	—	(10,628)	(10,628)
Other		—	—	—	—	1	1
Balance, June 30, 2024	71,264,947	$ 178,162	$ 3,771,696	$ 3,786,315	$ (17,036)	$ 105,183	$ 7,824,320

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, 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

	Six Months Ended June 30, 2024						
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, December 31, 2023	71,264,947	$ 178,162	$ 3,321,696	$ 3,759,299	$ (17,219)	$ 107,198	$ 7,349,136
Equity infusion from Pinnacle West		—	450,000	—	—	—	450,000
Net income		—	—	226,918	—	8,612	235,530
Other comprehensive income		—	—	—	183	—	183
Dividends on common stock		—	—	(199,900)	—	—	(199,900)
Capital activities by noncontrolling interests		—	—	—	—	(10,628)	(10,628)
Other		—	—	(2)	—	1	(1)
Balance, June 30, 2024	71,264,947	$ 178,162	$ 3,771,696	$ 3,786,315	$ (17,036)	$ 105,183	$ 7,824,320

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 Investment Company ("El Dorado"), and Pinnacle West Power, LLC ("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 variable interest entity ("VIE") related to a Captive Insurance Cell ("Captive"). The unaudited Condensed Consolidated Financial Statements for APS include the accounts of APS and the Palo Verde Generating Station ("Palo Verde") VIEs. See Note 8 for further discussion on Pinnacle West's VIEs. 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 that were previously held by Bright Canyon Energy Corporation ("BCE"). Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

BCE was a Pinnacle West subsidiary that was formed in 2014. On August 4, 2023, Pinnacle West entered into a purchase and sale agreement pursuant to which all of our equity interest in BCE was sold. The sale was completed on January 12, 2024. See Note 18 for more information relating to the sale of BCE.

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 2024 Form 10-K.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Cash Flow Information

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

	Six Months Ended June 30,	
	2025	2024
Cash paid during the period for:		
Income taxes, net of refunds	$ 7,743	$ 25,019
Interest, net of amounts capitalized	189,041	177,323
Significant non-cash investing and financing activities:		
Accrued capital expenditures	312,762	214,182
Dividends accrued but not yet paid	106,869	99,936
BCE Sale non-cash consideration (Note 18)	—	36,510

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

	Six Months Ended June 30,	
	2025	2024
Cash paid during the period for:		
Income taxes, net of refunds	$ 10,369	$ 9,729
Interest, net of amounts capitalized	158,073	152,535
Significant non-cash investing and financing activities:		
Accrued capital expenditures	312,762	214,182
Dividends accrued but not yet paid	106,900	100,000

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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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. 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,					
	2025			2024		
	Regulated Electricity Segment	Other	Pinnacle West Consolidated	Regulated Electricity Segment	Other	Pinnacle West Consolidated
Operating revenues	$ 1,359	$ —	$ 1,359	$ 1,309	$ —	$ 1,309
Fuel and purchased power	(477)	—	(477)	(437)	—	(437)
Operations and maintenance	(285)	(2)	(287)	(273)	1	(272)
Depreciation and amortization	(229)	—	(229)	(225)	—	(225)
Taxes other than income taxes	(58)	—	(58)	(59)	—	(59)
Pension and other postretirement non-service credits, net	4	—	4	13	—	13
Allowance for equity funds used during construction	15	—	15	9	—	9
Other income and expenses, net	(2)	9	7	—	—	—
Interest charges	(80)	(22)	(102)	(82)	(16)	(98)
Income taxes	(39)	4	(35)	(39)	7	(32)
Less: Net income attributable to noncontrolling interests	(4)	—	(4)	(4)	—	(4)
Net Income (Loss)	$ 204	$ (11)	$ 193	$ 212	$ (8)	$ 204

	Six Months Ended June 30,					
	2025			2024		
	Regulated Electricity Segment	Other	Pinnacle West Consolidated	Regulated Electricity Segment	Other	Pinnacle West Consolidated
Operating revenues	$ 2,391	$ —	$ 2,391	$ 2,261	$ —	$ 2,261
Fuel and purchased power	(857)	—	(857)	(795)	—	(795)
Operations and maintenance	(582)	(5)	(587)	(526)	(4)	(530)
Depreciation and amortization	(464)	—	(464)	(435)	—	(435)
Taxes other than income taxes	(117)	—	(117)	(118)	—	(118)
Pension and other postretirement non-service credits, net	7	—	7	25	(1)	24
Allowance for equity funds used during construction	28	—	28	19	—	19
Other income and expenses, net	2	20	22	3	21	24
Interest charges	(159)	(38)	(197)	(156)	(28)	(184)
Income taxes	(36)	7	(29)	(42)	6	(36)
Less: Net income attributable to noncontrolling interests	(9)	—	(9)	(9)	—	(9)
Net Income (Loss)	$ 204	$ (16)	$ 188	$ 227	$ (6)	$ 221

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	June 30, 2025			December 31, 2024		
	Regulated Electricity Segment	Other	Pinnacle West Consolidated	Regulated Electricity Segment	Other	Pinnacle West Consolidated
Total Assets	$ 29,083	$ 152	$ 29,235	$ 25,988	$ 115	$ 26,103

3. New Accounting Standards

ASU 2023-09, Income Taxes: Improvements to Income Tax Disclosures

In December 2023, a new accounting standard was issued that expands disclosures relating to income taxes. The expanded disclosures include a tabular income tax rate reconciliation, disclosure of specific reconciliation categories and reconciling items, the amount of income taxes paid by jurisdiction, and other disclosures. We will adopt this standard on December 31, 2025, using a prospective approach. The adoption of the new standard will result in changes to our income tax disclosures, but will not impact our accounting for income taxes or our financial statement results.

ASU 2024-03, Income Statement: 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 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.

ASU 2025-03, Business Combinations and Consolidation: Determining the Accounting Acquirer in the Acquisition of a Variable Interest Entity

In May 2025, a new accounting standard was issued that revises the guidance on identifying the accounting acquirer in a business combination in which the acquiree is a VIE that meets the definition of a business. Prior to the issuance of the amended guidance, for certain transactions, the primary beneficiary of the VIE was always required to be deemed the acquirer in the transaction. Under the amended guidance, an entity will now need to complete an assessment of the transaction to determine the acquiring entity and is no longer required to assume that the primary beneficiary is the acquirer in the transaction.

The standard will become effective for us on January 1, 2027, with early adoption permitted. We expect to adopt this guidance on January 1, 2027, and will apply the guidance prospectively to acquisition transactions occurring on and after the adoption date. Upon adoption, we do not expect the guidance will have a material impact on our financial statements. The adoption of this guidance will not impact the APS purchase transactions relating to the Palo Verde Sale Leaseback VIEs. See Note 8.

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,	
	2025	2024	2025	2024
Retail Electric Service				
Residential	$ 651,666	$ 658,158	$ 1,100,589	$ 1,090,850
Non-Residential	654,038	609,871	1,178,895	1,071,354
Wholesale Energy Sales	17,893	10,261	42,717	37,125
Transmission Services for Others	31,996	27,541	57,543	55,253
Other Sources	3,158	3,163	11,287	6,124
Total Operating Revenues	$ 1,358,751	$ 1,308,994	$ 2,391,031	$ 2,260,706

Retail Electric Revenues

All of Pinnacle West's retail electric revenues are generated by APS. Retail electric revenue is generated by the sale of electricity to our regulated customers within the authorized service territory at tariff rates approved by the ACC and based on customer usage. Revenues related to the sale of electricity are generally recognized when service is rendered, or electricity is delivered to customers. The billing of electricity sales to individual customers is based on the reading of their meters. We obtain customers' meter data on a systematic basis throughout the month, and generally bill customers within a month from when service was provided. Customers are generally required to pay for services within 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 6 for details related to proposed adjustments to rate design and modifications of cost allocation methodologies to reduce cross-subsidization by ensuring customers causing production costs are covering those costs through rates.

Wholesale Energy Sales and Transmission Services for Others

Revenues from wholesale energy sales and transmission services for others represent energy and transmission sales to wholesale customers. These activities 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 the U.S. Federal Energy Regulatory Commission ("FERC").

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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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, 2025 were $1,345 million and $2,364 million, respectively, and for the three and six months ended June 30, 2024 were $1,303 million and $2,246 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, 2025 our revenues that do not qualify as revenue from contracts with customers were $14 million and $27 million, respectively, and for the three and six months ended June 30, 2024 were $6 million and $15 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 6 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 continue to 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):

	June 30, 2025	December 31, 2024
Balance at beginning of period	$ 24,849	$ 22,433
Bad debt expense	11,287	35,799
Actual write-offs	(18,687)	(33,383)
Balance at end of period	$ 17,449	$ 24,849

5. 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, 2025, Pinnacle West had a $200 million revolving credit facility that matures on April 10, 2029. Pinnacle West has the option to increase the amount of the facility up to a total of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on Pinnacle West's senior unsecured debt credit ratings and the agreement includes a sustainability-linked pricing metric which provides for an interest rate reduction or increase, by meeting or missing, respectively, targets related to specific environmental and employee health and safety sustainability objectives. Under certain circumstances, the sustainability-linked pricing metric can be terminated for the final year of the credit facility. The facility is available to support Pinnacle West's general corporate purposes, including support for Pinnacle West's $200 million commercial paper program, for bank borrowings or for issuances of letters of credit. As of June 30, 2025, Pinnacle West had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under its credit facility, and $80 million of outstanding commercial paper borrowings. The weighted-average interest rate for the outstanding borrowings on June 30, 2025 was 4.59%.

Pinnacle West also has an outstanding 364-day $200 million term loan facility that matures on December 4, 2025. Borrowings under the facility bear interest at SOFR plus 0.95% per annum. On December 20, 2024, Pinnacle West drew the full amount of $200 million.

On February 28, 2024, Pinnacle West entered into equity forward sale agreements (the "February 2024 Forward Sale Agreements"), which may be settled with Pinnacle West common stock or cash. Pinnacle West also has an at-the-market equity distribution program (the "ATM Program") under which it may offer and sell common stock and enter into forward sale agreements from time to time, subject to market conditions and other factors. See Note 12 for more information on the February 2024 Forward Sale Agreements and the ATM Program.

On May 15, 2025, Pinnacle West issued $400 million of 4.90% senior unsecured notes that mature May 15, 2028 and $400 million of 5.15% senior unsecured notes that mature May 15, 2030. The net proceeds from the issuances were used to repay the $500 million of 1.3% senior unsecured notes that were maturing June 15, 2025 and for general corporate purposes.

APS

As of June 30, 2025, APS had a $1.25 billion revolving credit facility, that matures on April 10, 2029. APS has the option to increase the amount of the facility by up to a maximum of $400 million, for a total of $1.65 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings and the agreement includes a sustainability-linked pricing metric which provides for an interest rate reduction or increase, by meeting or missing, respectively, targets related to specific environmental and employee health and safety sustainability objectives. Under certain circumstances, the sustainability-linked pricing metric can be terminated for the final year of the credit facility. The facility is available to support APS's general corporate purposes, including support for APS's $1 billion commercial paper program, for bank borrowings or for issuances of letters of credit. As of June 30, 2025, APS had no outstanding borrowings under its revolving credit facility, no letters of credit outstanding under the credit facility, and $725 million of outstanding commercial paper borrowings. The weighted-average interest rate for the outstanding borrowings on June 30, 2025 was 4.58%.

On December 5, 2024, APS entered into a $400 million 364-Day Term Loan Agreement that matures on December 4, 2025. Borrowings under the facility bear interest at SOFR plus 0.90% per annum. On April 29, 2025, APS drew the full amount of $400 million.

On May 15, 2025, Pinnacle West contributed $300 million into APS in the form of an equity infusion. APS used this contribution to repay the $300 million of 3.15% senior notes that matured on the same date.

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.

See "Financial Assurances" in Note 10 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, 2025		As of December 31, 2024	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 1,663,965	$ 1,733,083	$ 1,367,770	$ 1,393,744
APS	7,193,037	6,321,922	7,490,878	6,525,248
Total	$ 8,857,002	$ 8,055,005	$ 8,858,648	$ 7,918,992

6. 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;

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

- 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 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 "Formula Rate Adjustment Mechanism" ("FRAM") to assist with reducing regulatory lag and allow for rate gradualism;
- elimination of the Lost Fixed Cost Recovery Adjustment Mechanism ("LFCR") following the first annual adjustment pursuant to the FRAM; and
- modification to the System Reliability Benefit Mechanism ("SRB") due to the Formula Rate Adjustment Mechanism proposal.

APS requested that the increase become effective in the second half of 2026. The hearing for this rate case is currently scheduled to begin in May 2026. 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 Recommended Opinion and Order ("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 all-source request for proposal ("ASRFP"), and (viii) recovery of all Demand Side Management ("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 CCT 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 Commission's December 17, 2024 decision on the rehearing. The Commission has taken no action on these requests. In addition, each of these parties have subsequently filed an appeal to the Arizona Court of Appeals seeking review of the ACC's decisions regarding the GAC and on rehearing. APS cannot predict the outcome of these proceedings.

Coal Community Transition

On October 31, 2019, APS filed an application with the ACC (the "2019 Rate Case") for an annual increase in retail base rates. As a part of the 2019 Rate Case decision, the ACC approved the Coal Community Transition ("CCT") Plan consisting of payments to certain impacted communities. APS has completed the following payments that are being recovered through rates related to CCT Plan: (i) \$10 million to the Navajo Nation; (ii) \$0.5 million to the Navajo County communities; and (iii) \$1 million to the Hopi Tribe. Consistent with APS's commitment to the impacted communities, APS has also completed the following payments: (i) \$2 million to the Navajo Nation for CCT; (ii) \$1.1 million to the Navajo County communities for CCT and economic development; and (iii) \$1.25 million to the Hopi Tribe for CCT and economic development. The ACC also authorized \$1.25 million to be spent for electrification of homes and businesses on each of the Navajo Nation and Hopi reservations. Expenditure of the recoverable funds for electrification of homes and businesses on the Navajo Nation and the Hopi reservations is contingent upon completion of a census of the unelectrified homes and businesses in each that are also within APS service territory. The census work was completed in November 2022 and disbursement of the funds for electrification of homes and businesses is planned to be finalized after discussions with the Navajo Nation and the Hopi Tribe are completed. On February 22, 2024, the ACC voted to not approve any further CCT funding.

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, the Residential Utility Consumer Office ("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 Arizona. 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 have also filed a Petition for Special Action with the Arizona Court of Appeals, requesting the case be sent back to the Superior Court for expedited consideration of the merits. APS cannot predict the outcome of this matter.

Cost Recovery Mechanisms

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

Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including, for example, solar, wind, biomass, biogas and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to recover the approved amounts for use on renewable energy projects. Each year, APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year's RES budget.

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. 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 2023. The ACC has not yet ruled on the 2024 RES Implementation Plan. APS cannot predict the outcome of this proceeding.

On July 1, 2024, APS filed its 2025 RES Implementation Plan and proposed a budget of approximately $92.7 million. 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 2024. The ACC has not yet ruled on the 2025 RES Implementation Plan. APS cannot predict the outcome of this proceeding.

On July 1, 2025, APS filed its 2026 RES Implementation Plan and proposed a total base RES budget of $110.1 million for 2026. 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. The ACC has not yet ruled on the 2026 RES Implementation Plan. APS cannot predict the outcome of this proceeding.

On June 14, 2021, APS filed an application for approval of its Green Power Partners Program ("GPP"). The GPP 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 September 1, 2021, the ACC approved the application. On June 28, 2024, APS filed an application for approval of modifications to the GPP and requested a renewable generation renewable energy credits waiver. The ACC has not yet ruled on the GPP application. APS cannot predict the outcome of this proceeding.

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 June 1, 2022, APS filed its 2023 Transportation Electrification ("TE") Plan. The 2023 TE Plan detailed APS's efforts to support transportation electrification in Arizona, including the Take Charge AZ Pilot Program and customer education and outreach related to transportation electrification. Subsequently, APS filed an amended 2023 TE Plan on November 30, 2022, that included a request for a $5 million budget. On December 12, 2023, the ACC approved the 2023 TE Plan without including the Take Charge AZ Program and its budget going forward, but allowed APS to complete projects already underway. Additionally, the ACC discontinued the residential EV Smart Charger rebate and approved modifications to the EV rate plan. APS incorporated its 2024 TE Plan in its annual DSM Implementation Plan filings.

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 TE 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, in contrast to the initially filed plan, supports an updated budget of $90.9 million, which reflects (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. The ACC has not yet ruled on the Second Amended 2024 DSM Implementation Plan. APS cannot predict the outcome of this proceeding.

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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.

On April 22, 2025, the ACC approved APS's request to refund uncommitted DSMAC and REAC surcharge funds of approximately $9 million and $43 million, respectively, during July and August of 2025. The actual refund amounts are dependent upon monthly usage billed.

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 the portion of APS's retail base rates attributable to fuel and purchased power costs ("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.

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

	Six Months Ended June 30,	
	2025	2024
Balance at beginning of period	$ 287,597	$ 463,195
Deferred fuel and purchased power costs	95,850	64,220
Amounts charged to customers	(201,035)	(204,748)
Balance at end of period	$ 182,412	$ 322,667

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

On November 30, 2021, APS filed its PSA rate for the PSA year beginning February 1, 2022. That rate was $0.007544 per kWh, which consisted of a forward component of $(0.004842) per kWh and a historical component of $0.012386 per kWh. The 2022 PSA rate was a $0.004 per kWh increase compared to the 2021 PSA year, which is the maximum permitted under the Plan of Administration for the PSA. These rates went into effect as filed on February 1, 2022.

On November 30, 2022, APS filed its PSA rate for the PSA year beginning February 1, 2023. In this filing, APS also requested that one of three different options be adopted to address the growing undercollected PSA balance. On February 23, 2023, the ACC approved an overall PSA rate of $0.019074 per kWh, which consisted of a forward component of $(0.005527) per kWh, a historical component of $0.013071 per kWh. On November 30, 2023, APS notified the ACC that it will be maintaining a PSA rate of $0.019074 per kWh and an updated PSA adjustment schedule would not be filed at that time. 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.

Environmental Improvement Surcharge ("EIS")

On March 5, 2024, because the ACC approved the elimination of the EIS, the surcharge is no longer in effect and any remaining amounts are being collected through base rates. The EIS permitted APS to recover the capital carrying costs (rate of return, depreciation and taxes) plus incremental operations and maintenance expenses associated with environmental improvements made outside of a test year to comply with environmental standards set by federal, state, tribal, or local laws and regulations.

Transmission Rates, Transmission Cost Adjustor ("TCA") 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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Effective June 1, 2023, APS's annual wholesale transmission revenue requirement for all users of its transmission system increased by approximately $34.7 million for the 12-month period beginning June 1, 2023, in accordance with the FERC-approved formula. Of this net amount, wholesale customer rates increased by approximately $20.7 million and retail customer rates would have increased by approximately $14 million. However, since changes in Retail Transmission Charges are reflected through the TCA after consideration of transmission recovery in retail base rates and the ACC-approved balancing account, the retail revenue requirement decreased by $10 million, resulting in reductions to the residential and commercial rates. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2023.

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.

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 distributed generation ("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 July 31, 2023, APS filed its 2023 annual LFCR adjustment, requesting that the annual LFCR recovery amount be increased to $68.7 million (a $9.6 million increase from previous levels). As a result of Decision No. 79293 in the 2022 Rate Case, APS transferred $27.1 million from the LFCR to base rates.

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). APS cannot predict the outcome of this matter.

Tax Expense Adjustor Mechanism ("TEAM")

The TEAM helps address potential federal income tax reform and enable the pass-through of certain income tax effects to customers. The TEAM expressly applies to APS's retail rates with the exception of a small subset of customers taking service under specially-approved tariffs. Currently, the TEAM is set to a zero rate as per 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, $33.7 million of which has been collected as of June 30, 2025, 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.

Net Metering

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 Distributed Generation 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 April 29, 2022, APS filed an application to decrease the RCP price from 9.4 cents per kWh, which had been in effect since October 1, 2021, to 8.46 cents per kWh, reflecting a 10% annual reduction, to become effective September 1, 2022. On July 12, 2022, the ACC approved the RCP as filed.

On May 1, 2023, APS filed an application for revisions to the RCP. This application would decrease the RCP price to 7.619 cents per kWh, reflecting a 10% annual reduction, to become effective September 1, 2023. On August 25, 2023, the ACC approved the RCP as filed.

On May 1, 2024, APS filed an application for revisions to the RCP. This application would decrease the RCP price to 6.857 cents 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 6.171 cents per kWh, reflecting a 10% annual reduction, to become effective September 1, 2025. The ACC has not yet ruled on the RCP application. 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 Distributed Generation 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. The ACC Hearing Division filed a ROO agreeing with Staff's recommendation, but the ACC has not yet acted on this ROO. APS cannot predict the outcome of this matter.

Energy Modernization Plan

On May 26, 2023, the ACC opened a new docket to review articles within the Arizona Administrative Code related to Resource Planning, the RES, and energy efficiency standards ("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 the 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. APS cannot predict the outcome of this matter.

Integrated Resource Planning ("IRP")

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 May 1, 2023, APS, Tucson Electric Power Company, and UNS Electric, Inc. filed a joint request for an extension to file the IRPs from August 1, 2023, to November 1, 2023. On June 21, 2023, the ACC granted the extension. As a result, APS filed its 2023 IRP on November 1, 2023. On January 31, 2024, stakeholders filed comments regarding the IRP, and APS filed its response to stakeholder comments on May 31, 2024. On July 31, 2024, the ACC held an IRP workshop where utilities and stakeholders presented on the 2023 IRPs. 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 resource adequacy prior to exiting Four Corners as well as analysis of impacts from western market participation and planned resource requirements in the next IRP.

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 customers for nonpayment from June 1 through October 15 each year ("Annual Disconnection Moratorium"). Since the Annual Disconnection Moratorium began, APS has experienced an increase in bad debt expense and the related write-offs of delinquent customer accounts. Pursuant to an ACC order, customers with past due balances of $75 or greater as of approximately one month prior to the end of the Annual Disconnection Moratorium are automatically placed on six-month payment arrangements.

Cholla Power Plant

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

Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS is allowed continued recovery of the net book value of the unit and the unit's decommissioning and other retirement-related costs, $25.8 million as of June 30, 2025, in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to regulatory assets. In accordance with the 2019 Rate Case decision, the regulatory asset is being amortized through 2033.

On August 14, 2024, APS filed a request with the ACC for a deferral order associated with unrecovered book value and closure costs of Cholla Units 1 and 3 related to the anticipated closure of Cholla in April 2025. This order would authorize APS to defer, for future recovery in rates, both the expenses necessary to close and decommission coal-fired power plant infrastructure at Cholla, including legally required site environmental remediation, coal combustion residuals ("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 cannot predict the outcome of this matter.

As previously planned, APS ceased operations at Cholla in March 2025 and formally retired Cholla Units 1 and 3 on April 30, 2025. At closure, 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 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 future shut-down and environmental remediation costs relating to Cholla that may be incurred after the 2025 proceeding.

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, $28.6 million as of June 30, 2025, 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, $4.7 million as of June 30, 2025. 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, Arizona Governor Hobbs 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.

Regulatory Assets and Liabilities

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

	Amortization Through	June 30, 2025	December 31, 2024
Pension	(a)	$ 733,970	$ 750,976
Income taxes — allowance for funds used during construction equity	2054	196,476	192,936
Deferred fuel and purchased power (b) (c)	2026	182,412	287,597
Ocotillo deferral	2034	107,353	114,775
Lease incentives	(g)	92,379	70,541
SCR deferral (e)	2038	80,154	83,123
Retired power plant costs	2033	62,607	68,380
FERC Transmission true up	2027	52,720	35,159
Income taxes — investment tax credit basis adjustment	2056	34,338	34,834
Deferred compensation	2036	33,977	33,108
Palo Verde VIEs (Note 8)	2046	20,531	20,611
Deferred property taxes	2027	19,634	23,918
Deferred fuel and purchased power — mark-to-market (Note 9)	2026	9,598	42,275
Mead-Phoenix transmission line — contributions in aid of construction ("CIAC")	2050	8,218	8,384
Loss on reacquired debt	2038	6,168	6,682
Active union medical trust	(f)	5,032	9,673
Navajo Coal reclamation	2026	4,670	7,905
Tax expense adjustor mechanism (b)	2031	4,206	4,534
Power supply adjustor - interest	2026	3,329	11,525
Other	Various	3,458	3,522
Total regulatory assets (d)		$ 1,661,230	$ 1,810,458
Less: current regulatory assets		$ 303,848	$ 420,969
Total non-current regulatory assets		$ 1,357,382	$ 1,389,489

(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 and result in lower future revenues. As a result of the 2019 Rate Case decision, the amount authorized for inclusion in rate base was determined using an averaging methodology, which resulted in a reduced return in retail rates. Subsequently, the 2022 Rate Case decision allowed for the full return on the pension asset in rate base. See Note 7 for further discussion.
(b) See "Cost Recovery Mechanisms" discussion above.
(c) Subject to a carrying charge.
(d) There are no regulatory assets for which the ACC has allowed recovery of costs, but not allowed a return by exclusion from rate base. FERC rates are set using a formula rate as described in "Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters."
(e) See "Court Resolution Surcharge" discussion above.
(f) Collected in retail rates.
(g) Amortization periods vary based on specific terms of lease contract.

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

	Amortization Through	June 30, 2025	December 31, 2024
Excess deferred income taxes - ACC — Tax Cuts and Jobs Act (a)	2046	$ 876,142	$ 888,896
Excess deferred income taxes - FERC — Tax Cuts and Jobs Act (a)	2058	205,166	207,400
Asset retirement obligations and removal costs	(d)	357,327	358,403
Other postretirement benefits	(c)	228,956	238,113
Four Corners coal reclamation	2038	97,617	77,532
Renewable energy standard (b)	2026	76,796	68,523
Income taxes — deferred investment tax credit	2056	65,449	66,327
Income taxes — change in rates	2053	58,246	59,133
Demand side management (b)	2025	30,983	23,927
Deferred fuel and purchased power — mark-to-market (Note 9)	2028	27,058	—
Sundance maintenance	2031	24,634	23,086
Spent nuclear fuel	2027	23,733	26,818
TCA Balancing Account (b)	2027	14,771	14,834
Tax expense adjustor mechanism (b)	2032	4,041	4,343
Property tax deferral	2027	3,690	4,785
Other	Various	128	113
Total regulatory liabilities		$ 2,094,737	$ 2,062,233
Less: current regulatory liabilities		$ 182,458	$ 206,955
Total non-current regulatory liabilities		$ 1,912,279	$ 1,855,278

(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) See "Cost Recovery Mechanisms" discussion above.
(c) See Note 7.
(d) In accordance with regulatory accounting, APS accrues removal costs for its regulated assets, even if there is no legal obligation for removal.

7. Retirement Plans and Other Postretirement Benefits

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

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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,	
	2025	2024	2025	2024	2025	2024	2025	2024
Service cost-benefits earned during the period	$ 11,127	$ 11,190	$ 22,076	$ 21,821	$ 2,059	$ 2,518	$ 4,041	$ 4,977
Non-service costs (credits):								
Interest cost on benefit obligation	38,584	37,085	77,560	74,321	5,070	5,472	10,172	11,085
Expected return on plan assets	(44,849)	(47,342)	(89,396)	(94,325)	(12,142)	(11,708)	(24,284)	(23,417)
Amortization of:								
Prior service credit (a)	—	—	—	—	—	(9,447)	(1,265)	(18,894)
Net actuarial loss (gain)	11,248	10,014	23,366	20,958	(2,965)	(2,258)	(5,864)	(4,338)
Net periodic benefit costs (credits)	$ 16,110	$ 10,947	$ 33,606	$ 22,775	$ (7,978)	$ (15,423)	$ (17,200)	$ (30,587)
Portion of costs (credits) charged to expense	$ 9,365	$ 5,500	$ 19,826	$ 11,837	$ (6,399)	$ (11,515)	$ (13,272)	$ (22,821)

(a) Prior-service costs or credits reflect the impact of modifications to the pension or postretirement plan benefits. The impact of these modifications is amortized over a period which reflects the demographics of the impacted population. In 2014, Pinnacle West made changes to the postretirement benefits offered to Medicare eligible retirees which resulted in prior-service credits. We have been amortizing these prior-serviced credits since 2015 and they became fully amortized as of January 31, 2025.

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 and we do not expect to make any voluntary contributions in 2025, 2026 or 2027. With regard to contributions to our other postretirement benefit plan, we have not made a contribution year-to-date in 2025 and do not expect to make any contributions in 2025, 2026 or 2027.

8. 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 10 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 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, 2025, of $1.7 million and $2.4 million respectively, and zero for the three and six months ended June 30, 2024. Amounts are fully attributable to Pinnacle West shareholders. Consolidation impacts the Pinnacle West Condensed Consolidated Income Statement's operations and maintenance expense and other income line items.

Pinnacle West's Condensed Consolidated Balance Sheets as of June 30, 2025 and December 31, 2024 include $39 million and $34 million, respectively, of assets relating to the Captive that is reported within the other special use funds line item. See Notes 13 and 14 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 VIEs lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. Under the current lease terms in effect, APS will retain the assets through 2033 under all three lease agreements, and will be required to make payments relating to the three leases in total of approximately $21 million annually for the period 2025 through 2033. At the end of the lease period, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors. These lease terms and provisions are subject to change upon the completion of the 2025 purchase agreements that are described below.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

As a result of consolidation, we eliminate lease accounting and instead recognize depreciation expense, resulting in an increase in net income for the three and six months ended June 30, 2025, of $4 million and $9 million respectively, and for the three and six months ended June 30, 2024, 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 these VIEs (dollars in thousands):

	June 30, 2025	December 31, 2024
Palo Verde sale leaseback property, plant and equipment, net of accumulated depreciation	$ 80,622	$ 82,556
Equity — Noncontrolling interests	101,152	103,167

Assets of the VIEs are restricted and may only be used for payment to the noncontrolling interest holders. These assets are reported on our Condensed Consolidated Financial Statements.

APS is exposed to losses relating to these VIEs upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the Nuclear Regulatory Commission ("NRC")) issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to make specified payments to the VIEs' noncontrolling equity participants and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written-down in value. If such an event were to occur during the lease periods, APS may be required to pay the noncontrolling equity participants approximately $345 million beginning in 2025, and up to $501 million over the lease extension terms.

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

In June 2025, APS executed purchase agreements relating to two of the three VIE lease arrangements. These purchase agreements are contingent upon standard closing conditions, including APS receiving FERC approval. APS has submitted filings with the FERC pertaining to these transactions, which are currently pending FERC review. If the closing conditions are satisfied, APS will acquire the leased Palo Verde interests from the VIE lessor owners for a combined total of approximately $199 million. APS will then own these leased interests, the two lease agreements will terminate, and APS will have no further payment obligations to the VIE lessors. If the closing occurs, APS will own approximately 24% of Unit 2 and its leasehold interest will be approximately 5.2%. Subject to the closing conditions being satisfied, we expect the transactions to close by December 31, 2025. The VIE lease agreement that is not subject to the purchase agreements will remain in effect and is not impacted by the purchase transactions. As of June 30, 2025, the purchase agreements did not impact our financial statement results or the accounting for these VIEs.

9. 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 13 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 12 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 6. 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, 2025**	**December 31, 2024**
Power	GWh	1,555	1,051
Gas	Billion cubic feet	286	235

Gains and Losses from Energy Derivative Instruments

For the three and six months ended June 30, 2025 and 2024, 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, 2025	Three Months Ended June 30, 2024	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
Net Gain (Loss) Recognized in Income	Fuel and purchased power (a)	$ (75,934)	$ (2,752)	$ 40,770	$ (58,694)

(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.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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.

As of June 30, 2025: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amounts Reported on Balance Sheets
Current assets	$ 22,143	$ (11,245)	$ 10,898	$ 5	$ 10,903
Investments and other assets	34,203	—	34,203	—	34,203
Total assets	56,346	(11,245)	45,101	5	45,106
Current liabilities	(31,741)	11,245	(20,496)	(5,196)	(25,692)
Deferred credits and other	(7,144)	—	(7,144)	—	(7,144)
Total liabilities	(38,885)	11,245	(27,640)	(5,196)	(32,836)
Total	$ 17,461	$ —	$ 17,461	$ (5,191)	$ 12,270

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting.
(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $5,196 thousand and cash margin provided to counterparties of $5 thousand.

As of December 31, 2024: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amounts Reported on Balance Sheets
Current assets	$ 13,718	$ (3,158)	$ 10,560	$ 18	$ 10,578
Investments and other assets	6,610	(630)	5,980	—	5,980
Total assets	20,328	(3,788)	16,540	18	16,558
Current liabilities	(52,527)	3,158	(49,369)	(2,971)	(52,340)
Deferred credits and other	(10,076)	630	(9,446)	—	(9,446)
Total liabilities	(62,603)	3,788	(58,815)	(2,971)	(61,786)
Total	$ (42,275)	$ —	$ (42,275)	$ (2,953)	$ (45,228)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting.
(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $2,971 thousand and cash margin provided to counterparties of $18 thousand.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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, 2025, we have four counterparties for which our exposure represents approximately 54% of Pinnacle West's $45.1 million of risk management assets. This exposure relates to ISDA master agreements with the respective counterparties. The counterparties are rated as investment grade by Standard & Poor's. 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 to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. To manage credit risk, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

Certain of our 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, 2025
Aggregate fair value of derivative instruments in a net liability position	$ 37,251
Additional collateral in the event credit-risk related contingent features were fully triggered (a)	980

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

We also have energy related non-derivative instrument contracts, including energy storage lease contracts, with investment grade credit-related contingent features, which could also require us to post additional collateral of approximately $417 million if our debt credit ratings were to fall below investment grade.

10. Commitments and Contingencies

Palo Verde Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the U.S. Department of Energy ("DOE") in the U.S. Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE's breach of the Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste ("Standard Contract") for failing to accept Palo Verde's spent nuclear fuel and high level waste from January 1, 2007, through June 30, 2011, 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 incurred 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 has recovered costs for eleven claims pursuant to the terms of the August 15, 2014 settlement agreement, for eleven separate time periods during July 1, 2011, through October 31, 2024. The DOE has approved and paid approximately $174.3 million for these claims (APS's share is approximately $50.7 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 Rate Case decision, this regulatory liability is being refunded to customers.

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 Nuclear Electric Insurance Limited

("NEIL"). APS is subject to retrospective premium adjustments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $24.2 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 $66.4 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 third-party 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 third-party insurance policies. 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. See Note 8 for additional details.

Fuel and Purchased Power Commitments and Purchase Obligations

As of June 30, 2025, other than those described, there have been no material changes outside of the normal course of business in contractual obligations from the information provided in our 2024 Form 10-K. In July 2025, APS executed a long-term gas transportation precedent agreement which will provide APS capacity to transport natural gas along a gas pipeline that will be newly constructed, owned and operated by a third-party. APS's purchase commitments relating to the gas transportation services agreement that will follow this long-term gas transportation precedent agreement are expected to begin in 2029 and are estimated to be a total of $7.3 billion over the 25-year service period. APS's purchase obligations relating to this agreement are conditional upon the successful construction and commercial operation of the gas pipeline.

See Note 5 for discussion regarding changes in our short-term and long-term debt obligations. See Note 8 for contractual obligations relating to the pending purchase of two Palo Verde Sale Leaseback VIEs.

Superfund and Other Related Matters

The Comprehensive Environmental Response Compensation and Liability Act ("Superfund" or "CERCLA") establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who released, generated, transported to or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible (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, Operable Unit 3 ("OU3") in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study ("RI/FS"). The RI/FS for OU3 was finalized and submitted to EPA at the end of 2022. EPA notified APS that the RI/FS was approved on September 11, 2024. APS's estimated costs related to this investigation and study are approximately $3 million. APS anticipates incurring additional expenditures in the future, but because the final costs associated with remediation requirements set forth in the RI/FS are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

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 ("RID"). 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 APS's Ocotillo power plant site located in Tempe, Arizona. In particular, EPA seeks information from APS regarding APS's use, storage, and disposal of substances containing per-and polyfluoroalkyl ("PFAS") compounds at the Ocotillo power plant site in order to aid EPA's investigation into actual or threatened releases of PFAS into groundwater within the South Indian Bend Wash ("SIBW") Superfund site. The SIBW Superfund site includes the APS Ocotillo power plant 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 SIBW site, including the Ocotillo power plant, 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 greenhouse gases, 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 ("WIIN") 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. Arizona Department of Environmental Quality ("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 WIIN 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 CCR management units ("CCRMUs"), which contain at least 1,000 tons of CCR, broadly encompass any location at an operating coal-fired power plant where CCRs would have been placed on land. As proposed, 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. At this time, APS is still evaluating the impacts of this final regulation on its business, with initial CCRMU site surveys due to be completed by February 2026 and final site investigation reports to be finalized by February 2027. 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 those evaluations and site investigations, the costs associated with APS's management of CCR could materially increase, which could affect our financial condition, results of operations, or cash flows. In addition, EPA stated on March 12, 2025 that it intends to prioritize a number of timely actions on coal ash, including state permit program reviews and updates to the coal ash regulations. We cannot predict the outcome of a future rulemaking or other regulatory proceedings aimed at changing the current EPA CCRMU rules.

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. The Cholla Plant disposed of CCR in ash ponds and dry storage areas prior to retirement. 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 subject to alternative closure). 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 Asset Retirement Obligations, Removal Costs and 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 ("ACE") regulations, which were a far narrower set of rules. While the U.S. Court of Appeals for the D.C. Circuit subsequently vacated the ACE 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.

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 carbon capture and sequestration or utilization controls ("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. The D.C. Circuit granted EPA's motion for an indefinite abeyance on April 25, 2025. 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 carbon capture and sequestration and achieve 90% capture efficiency may not be feasible. Future resource plans and procurement efforts implicating the development of such new generation remains 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 section 111(d) 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 are 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.

Effluent Limitation Guidelines

EPA published effluent limitation guidelines ("ELG") on October 13, 2020, and, based off those guidelines, APS completed a National Pollutant Discharge Elimination System ("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. Nonetheless, 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 June 30, 2025, EPA announced that it intends to take next steps to reconsider the ELG standards. EPA intends to put forth an initial rulemaking that would propose extending the compliance deadlines for many of the zero-discharge effluent limitations and pretreatment requirements in the 2024 Rule. This initial rulemaking will also seek additional information on zero-discharge technologies, including cost and performance data. This information is intended to help EPA determine whether to move forward with a second rulemaking to address zero-discharge technologies. We cannot predict the outcome of any future rulemaking or other regulatory proceedings aimed at modifying the current ELG standards.

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 National Ambient Air Quality Standards ("NAAQS"). Thermal power plant emission limitations are a key aspect of these regulations, which involve emission allowance trading for nitrogen oxide ("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 under the current administration announced its intention to reconsider the Good Neighbor Plan. As such, while EPA may elect to resume work on and finalize this proposal in the future, it is unlikely to do so over a near-term horizon. APS cannot predict the outcome of any future EPA efforts to add Arizona to the federal Good Neighbor Plan (which depends on action disapproving the Arizona State Implementation Plan) or whether the Good Neighbor Plan itself will remain in effect pending the outcome of judicial review in the D.C. Circuit Court of Appeals. Should 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 April 25, 2024, EPA finalized revisions to the existing MATS regulations governing emissions of toxic air pollution from existing coal-fired power plants. The final regulations increase the stringency of filterable particulate matter limits used to demonstrate compliance with MATS and require the use of continuous emissions monitoring systems to ensure compliance (as opposed to periodic performance testing). These final regulations will take effect for existing coal-fired power plants, such as Four Corners, within three years of publication in the Federal Register. Based on APS's assessment of the revised MATS regulations, this final rule is unlikely to have a material impact on plant operations or require significant capital expenditures to ensure compliance.

On June 11, 2025, EPA issued a proposed rule to repeal specific amendments finalized in the 2024 MATS regulations. EPA is now proposing a full repeal of the Biden administration's revisions to the 2012 MATS regulations, which would result in a return to EPA's prior 2020 determination that no changes are warranted to the original 2012 MATS emission limits. Comments on EPA's proposal are due by August 11, 2025.

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.

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, 2025, standby letters of credit totaled approximately $29.2 million and surety bonds totaled approximately $23.4 million; both will expire through 2026. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

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

Pinnacle West has issued parental guarantees and has provided indemnification under certain surety bonds for APS which were not material as of June 30, 2025. 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 Navajo Transitional Energy Corporation ("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 production tax credit ("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, 2025, there is approximately $27.5 million of remaining guarantees relating to these PTC Guarantees that are expected to terminate by 2031.

Pinnacle West has issued various performance guarantees in connection with the Kūpono Solar Project investment financing and is exposed to losses relating to these guarantees upon the occurrence of certain events that we consider to be remote. These guarantees were issued in connection with Pinnacle West's BCE subsidiary, which was sold to Ameresco in 2024 (the "BCE Sale"). See Note 18. Subsequent to the BCE Sale, Pinnacle West continues to maintain these Kūpono Solar Project investment financing guarantees. 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.

11. 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,	
	2025	2024	2025	2024
Other income:				
Interest income (a)	$ 4,260	$ 5,396	$ 10,256	$ 12,956
Investment gain — net (b)	6,504	—	17,488	—
Gain on sale of BCE (Note 18)	—	—	—	22,988
Miscellaneous	1,340	489	1,821	548
Total other income	$ 12,104	$ 5,885	$ 29,565	$ 36,492
Other expense:				
Non-operating costs	$ (3,245)	$ (2,038)	$ (5,474)	$ (8,188)
Investment losses — net	—	(497)	—	(1,274)
Miscellaneous	(1,014)	(497)	(1,355)	(1,137)
Total other expense	$ (4,259)	$ (3,032)	$ (6,829)	$ (10,599)

(a) Interest income is primarily related to PSA interest. See Note 6.
(b) Investment gain is primarily related to El Dorado's equity investment in SAI Advanced Power Solutions.

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,	
	2025	2024	2025	2024
Other income:				
Interest income (a)	$ 3,674	$ 4,602	$ 9,281	$ 11,398
Miscellaneous	—	(11)	115	48
Total other income	$ 3,674	$ 4,591	$ 9,396	$ 11,446
Other expense:				
Non-operating costs	$ (2,876)	$ (2,397)	$ (4,868)	$ (4,652)
Miscellaneous	(1,014)	(497)	(1,355)	(1,136)
Total other expense	$ (3,890)	$ (2,894)	$ (6,223)	$ (5,788)

(a) Interest income is primarily related to PSA interest. See Note 6.

12. Common Stock Equity and Earnings Per Share

ATM Program

On November 8, 2024, Pinnacle West entered into an equity distribution sales agreement, pursuant to which Pinnacle West may sell, from time to time, up to $900 million of its common stock through an at-the-market ("ATM") equity distribution program, which includes the ability to enter into forward sale agreements. As of June 30, 2025, approximately $800 million of common stock is available to be issued under the ATM Program, which takes into account the forward sale agreements in effect as of June 30, 2025.

As of June 30, 2025, Pinnacle West had two outstanding forward sale agreements under the ATM Program relating to approximately $100 million of common stock. These agreements are the November 2024 ATM Forward Sale Agreement and the March 2025 ATM Forward Sale Agreement (collectively, the "ATM Forward Sale Agreements"), which may be settled at Pinnacle West's discretion no later than June 30, 2026 and September 14, 2026, respectively. On a given settlement date, Pinnacle West will issue shares of common stock at the then-applicable forward sales price. Additionally, the terms of the forward sale agreements allow Pinnacle West, at its option, to settle the agreements with the counterparties by delivering cash, in lieu of shares.

The following table presents the calculation of Pinnacle West's ATM Program as of June 30, 2025 (in thousands, except share amounts and price per share):

	As of June 30, 2025	
	November 2024 ATM Forward Sale Agreement	March 2025 ATM Forward Sale Agreement
Initial Price		
Number of Shares	552,833	544,959
Forward Sales Price Per Share (a)	$ 89.73	$ 90.83
Aggregate Value (in thousands)	$ 49,606	$ 49,499

(a) Subject to certain adjustments.

Non-ATM February 2024 Forward Sale Agreements

On February 28, 2024, Pinnacle West executed equity forward sale agreements ("February 2024 Forward Sale Agreements"). The February 2024 Forward Sale Agreements may be settled at Pinnacle West's discretion no later than September 4, 2025, and were not issued under the ATM Program discussed above. On a settlement date, Pinnacle West will issue shares of Pinnacle West common stock and receive 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 following table presents the calculation of Pinnacle West's February 2024 Forward Sale Agreements as of June 30, 2025 (in thousands, except share amounts and price per share):

		As of June 30, 2025
		February 2024 Forward Sale Agreements
Initial Price		
Number of Shares		11,240,601
Forward Sales Price Per Share (a)	$	64.51
Aggregate Value (in thousands)	$	725,131
Settlements		
Date		12/23/2024
Number of Shares Settled (b)		5,377,115
Forward Sales Price Upon Settlement	$	64.17
Net Proceeds (in thousands) (c)	$	345,049

(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. The Convertible Notes bear interest at a fixed rate of 4.75% per year, 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, 2025, the conditions allowing holders to convert their Convertible Notes were not met, and as a result, the Convertible Notes were classified as long term debt on Pinnacle West's Condensed Consolidated Balance Sheets with a carrying amount of $525 million, including unamortized debt issuance costs of $5 million. The estimated fair value of the Convertible Notes as of June 30, 2025 was $568 million (Level 2 within the fair value hierarchy).

As of June 30, 2025, based on Pinnacle West's average stock price and the relevant terms of the Convertible Notes, there were no shares of Pinnacles West's common stock included in basic or diluted EPS relating to the potential conversion of the Convertible Notes.

Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
Net income attributable to common shareholders	$ 192,564	$ 203,805	$ 187,920	$ 220,667
Weighted average common shares outstanding — basic	119,517	113,695	119,555	113,658
Net effect of dilutive securities:				
Contingently issuable performance shares and restricted stock units	548	489	523	408
Dilutive shares related to equity forward sale agreements (a)	1,800	1,619	1,735	949
Total contingently issuable shares	2,348	2,108	2,258	1,357
Weighted average common shares outstanding — diluted	121,865	115,803	121,813	115,015
Earnings per weighted-average common share outstanding				
Net income attributable to common shareholders — basic	$ 1.61	$ 1.79	$ 1.57	$ 1.94
Net income attributable to common shareholders — diluted	$ 1.58	$ 1.76	$ 1.54	$ 1.92

(a) For the three and six months ended June 30, 2025, the diluted weighted average common shares excludes 51,380 and 244,134 shares, respectively, and for the three and six months ended June 30, 2024, diluted weighted average common shares excludes 348,499 and 348,499 shares, respectively, relating to the Convertible Notes. These potentially issuable shares were excluded from the calculation of diluted shares 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 earnings per share ("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 less that 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.

On May 21, 2025, Pinnacle West shareholders approved an amendment to the Company's Articles of Incorporation to increase the number of authorized shares of common stock from 150,000,000 to 300,000,000. This amendment was subsequently filed with the ACC on May 22, 2025.

13. Fair Value Measurements

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

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

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

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

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

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

Recurring Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, and investments held in the nuclear decommissioning trusts and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefit plans. See Note 7 in the 2024 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 14 for additional discussion about our investment accounts.

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

Fixed Income Securities

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

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

Equity Securities

The nuclear decommissioning trusts' 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, 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	$ —	$ 52,106	$ 4,240	$ (11,240)	(a)	$ 45,106
Nuclear decommissioning trusts:						
Equity securities	17,914	—	—	3,676	(b)	21,590
U.S. commingled equity funds	—	—	—	450,053	(c)	450,053
U.S. Treasury debt	347,666	—	—	—		347,666
Corporate debt	—	231,394	—	—		231,394
Mortgage-backed securities	—	224,600	—	—		224,600
Municipal bonds	—	36,981	—	—		36,981
Other fixed income	—	25,574	—	—		25,574
Subtotal nuclear decommissioning trusts	365,580	518,549	—	453,729		1,337,858
Other special use funds:						
Equity securities	64,322	—	—	2,844	(b)	67,166
U.S. Treasury debt	356,166	—	—	—		356,166
Subtotal other special use funds (d)	420,488	—	—	2,844		423,332
Total assets	$ 786,068	$ 570,655	$ 4,240	$ 445,333		$ 1,806,296
LIABILITIES						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (15,853)	$ (23,032)	$ 6,049	(a)	$ (32,836)

(a) Represents counterparty netting, margin, and collateral. See Note 9.
(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 $38.5 million related to Pinnacle West's Captive investments that are classified within Level 1 equity securities. See Note 8.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value at December 31, 2024 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	$ 23	$ —	$ —	$ —		$ 23
Risk management activities — derivative instruments:						
Commodity contracts	—	13,152	7,176	(3,770)	(a)	16,558
Nuclear decommissioning trusts:						
Equity securities	11,859	542	—	3,335	(b)	15,736
U.S. commingled equity funds	—	—	—	423,069	(c)	423,069
U.S. Treasury debt	367,396	—	—	—		367,396
Corporate debt	—	203,180	—	—		203,180
Mortgage-backed securities	—	208,533	—	—		208,533
Municipal bonds	—	37,429	—	—		37,429
Other fixed income	—	27,502	—	—		27,502
Subtotal nuclear decommissioning trusts	379,255	477,186	—	426,404		1,282,845
Other special use funds:						
Cash equivalents	25,000	—	—	—	(d)	25,000
Equity securities	24,962	—	—	2,851	(b) (d)	27,813
U.S. Treasury debt	355,544	—	—	—		355,544
Subtotal other special use funds (d)	405,506	—	—	2,851		408,357
Total assets	$ 784,784	$ 490,338	$ 7,176	$ 425,485		$ 1,707,783
LIABILITIES						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (40,388)	$ (22,215)	$ 817	(a)	$ (61,786)

(a) Represents counterparty netting, margin, and collateral. See Note 9.
(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 $34.2 million related to Pinnacle West's Captive investments that are classified within Level 1, $25.0 million in cash equivalents and $9.2 million related to equity securities. See Note 8.

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, 2025 and December 31, 2024:

	June 30, 2025 Fair Value (thousands)		**Valuation**	**Significant**		**Weighted-Average**
Commodity Contracts	**Assets**	**Liabilities**	**Technique**	**Unobservable Input**	**Range**	**(b)**
Electricity Forward Contracts (a)	$ 3,994	$ 22,954	Discounted cash flows	Electricity forward price (per MWh)	$24.00 - $164.62	$92.66
Natural Gas Forward Contracts (a)	246	78	Discounted cash flows	Natural gas forward price (per MMBtu)	$0.00 - $0.07	$0.04
Total	$ 4,240	$ 23,032				

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

	December 31, 2024 Fair Value (thousands)		**Valuation**	**Significant**		**Weighted-Average**
Commodity Contracts	**Assets**	**Liabilities**	**Technique**	**Unobservable Input**	**Range**	**(b)**
Electricity Forward Contracts (a)	$ 708	$ 21,890	Discounted cash flows	Electricity forward price (per MWh)	$ 25.25 - $151.11	$106.06
Natural Gas Forward Contracts (a)	6,468	325	Discounted cash flows	Natural gas forward price (per MMBtu)	$(0.89) - $1.47	$0.71
Total	$ 7,176	$ 22,215				

(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	**2025**	**2024**	**2025**	**2024**
Balance at beginning of period	$ (22,840)	$ (15,971)	$ (15,039)	$ 4,921
Total net losses realized/unrealized:				
Deferred as a regulatory asset or liability	2,194	(9,808)	(3,629)	(33,408)
Settlements	1,883	7,240	(404)	9,948
Transfers into Level 3 from Level 2	(329)	(4,565)	(388)	(4,565)
Transfers from Level 3 into Level 2	300	1,464	668	1,464
Balance at end of period	$ (18,792)	$ (21,640)	$ (18,792)	$ (21,640)
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 5 for our long-term debt fair values.

14. 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 13 for a discussion of how fair value is determined and the classification of the investments within the fair value hierarchy. The investments in each trust or account are restricted for use and are intended to fund specified costs and activities as further described for each fund below.

Nuclear Decommissioning Trusts

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

Coal Reclamation Escrow Account

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

Active Union Employee Medical Account

APS has investments restricted for paying active union employee medical costs. These investments may be used to pay active union employee medical costs incurred in the current and future periods. In 2024, APS was reimbursed $14 million for prior year active union employee medical claims from the active union employee medical account. The account is invested primarily in fixed income securities. In accordance with the ratemaking treatment, APS has deferred the unrealized gains and losses (including credit losses) in other regulatory assets and liabilities. 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 in 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, 2025					
	Fair Value					
Investment Type:	**Nuclear Decommissioning Trusts**	**Other Special Use Funds**	**Total**		**Total Unrealized Gains**	**Total Unrealized Losses**
Equity securities	$ 467,967	$ 64,322	$ 532,289		$ 385,464	$ —
Available for sale-fixed income securities	866,215	356,166	1,222,381	(a)	15,242	(19,502)
Other	3,676	2,844	6,520	(b)	—	—
Total	$ 1,337,858	$ 423,332	$ 1,761,190	(c)	$ 400,706	$ (19,502)

(a) As of June 30, 2025, the amortized cost basis of these available-for-sale investments is $1,227 million.
(b) Represents net pending securities sales and purchases.
(c) All amounts pertain to APS, with the exception of $38.5 million of other special use fund investments in equity securities and $2.0 million of unrealized gains relating to the Captive.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

	December 31, 2024					
	Fair Value					
Investment Type:	Nuclear Decommissioning Trusts	Other Special Use Funds	Total		Total Unrealized Gains	Total Unrealized Losses
Equity securities	$ 435,470	$ 24,962	$ 460,432		$ 359,127	$ (176)
Available for sale-fixed income securities	844,040	355,544	1,199,584	(a)	7,717	(31,960)
Other	3,335	27,851	31,186	(b)	—	—
Total	$ 1,282,845	$ 408,357	$ 1,691,202	(c)	$ 366,844	$ (32,136)

(a) As of December 31, 2024, the amortized cost basis of these available-for-sale investments is $1,224 million.
(b) Represents net pending securities sales and purchases.
(c) All amounts pertain to APS, with the exception of $34.2 million of other special use fund investments in equity securities relating to 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
2025				
Realized gains	$ 1,702	$ —		$ 1,702
Realized losses	$ (2,611)	$ —		$ (2,611)
Proceeds from the sale of securities (a)	$ 342,313	$ 91,517	(b)	$ 433,830
2024				
Realized gains	$ 8,943	$ —		$ 8,943
Realized losses	$ (3,706)	$ —		$ (3,706)
Proceeds from the sale of securities (a)	$ 270,631	$ 57,874		$ 328,505

(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 $25.2 million of other special use fund proceeds from the sale of securities relating to the Captive.

	Six Months Ended June 30,		
	Nuclear Decommissioning Trusts	Other Special Use Funds	Total
2025			
Realized gains	$ 3,360	$ —	$ 3,360
Realized losses	$ (5,372)	$ —	$ (5,372)
Proceeds from the sale of securities (a)	$ 758,914	$ 160,730 (b)	$ 919,644
2024			
Realized gains	$ 63,435	$ 80	$ 63,515
Realized losses	$ (6,521)	$ —	$ (6,521)
Proceeds from the sale of securities (a)	$ 648,453	$ 123,922	$ 772,375

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

Fixed Income Securities Contractual Maturities

The fair value fixed income securities summarized by contractual maturities as of June 30, 2025 is as follows (dollars in thousands):

	Nuclear Decommissioning Trusts	Coal Reclamation Escrow Account	Active Union Employee Medical Account	Total
Less than one year	$ 19,613	$ 83,392	$ 39,865	$ 142,870
1 year – 5 years	278,017	58,611	158,159	494,787
5 years – 10 years	171,593	—	16,139	187,732
Greater than 10 years	396,992	—	—	396,992
Total	$ 866,215	$ 142,003	$ 214,163	$ 1,222,381

15. Changes in Accumulated Other Comprehensive Loss

The following tables show the changes in Pinnacle West’s consolidated accumulated other comprehensive 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, 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)
Balance March 31, 2024	$ (34,192)		$ 1,610	$ (32,582)
Other comprehensive (loss) before reclassifications	(778)		(399)	(1,177)
Amounts reclassified from accumulated other comprehensive loss	465	(a)	—	465
Balance June 30, 2024	$ (34,505)		$ 1,211	$ (33,294)

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 7

	Pension and Other Postretirement Benefits		Derivative Instruments	Total
Six Months Ended June 30				
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)
Balance December 31, 2023	$ (34,754)		$ 1,610	$ (33,144)
Other comprehensive (loss) before reclassifications	(778)		(399)	(1,177)
Amounts reclassified from accumulated other comprehensive loss	1,027	(a)	—	1,027
Balance June 30, 2024	$ (34,505)		$ 1,211	$ (33,294)

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 7.

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, 2025	$ (13,710)	
Other comprehensive (loss) before reclassifications	(504)	
Amounts reclassified from accumulated other comprehensive loss	368	(a)
Balance June 30, 2025	$ (13,846)	
Balance March 31, 2024	$ (16,729)	
Other comprehensive (loss) before reclassifications	(717)	
Amounts reclassified from accumulated other comprehensive loss	410	(a)
Balance June 30, 2024	$ (17,036)	

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 7.

	Pension and Other Postretirement Benefits	
Six Months Ended June 30		
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)	
Balance December 31, 2023	$ (17,219)	
Other comprehensive (loss) before reclassifications	(717)	
Amounts reclassified from accumulated other comprehensive loss	900	(a)
Balance June 30, 2024	$ (17,036)	

(a) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 7.

16. Leases

We lease certain land, buildings, vehicles, equipment, and other property through operating rental agreements with varying terms, provisions, and expiration dates. APS also has certain power purchase or purchased power agreements ("PPAs") and energy storage agreements that qualify as lease arrangements. Our leases have remaining terms that expire in 2025 through 2073. Substantially all of our leasing activities relate to APS.

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. These lessor trust entities have been deemed VIEs for which APS is the primary beneficiary. As the primary beneficiary, APS consolidated these lessor trust entities. The impacts of these sale leaseback transactions are excluded from our lease disclosures as lease accounting is eliminated upon consolidation. See Note 8 for a discussion of VIEs.

APS has PPAs that allow APS 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.

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 May 2025.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
Operating Lease Cost - PPAs and Energy Storage PPA Lease Contracts	$ 76,947	$ 39,391	$ 89,494	$ 40,328
Operating Lease Cost - Land, Property, and Other Equipment	5,286	5,025	10,623	9,798
Total Operating Lease Cost	82,233	44,416	100,117	50,126
Variable Lease Cost (a)	32,838	47,783	54,208	69,347
Short-term Lease Cost	528	6,445	1,120	9,245
Total Lease Cost	$ 115,599	$ 98,644	$ 155,445	$ 128,718

(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 6. 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, 2025		
Year	PPAs and Energy Storage PPA Lease Contracts	Land, Property and Equipment Leases	Total
2025 (remaining six months of 2025)	$ 216,654	$ 9,838	$ 226,492
2026	355,402	17,062	372,464
2027	381,465	14,481	395,946
2028	385,407	11,789	397,196
2029	389,492	9,656	399,148
2030	393,621	5,663	399,284
Thereafter	3,462,329	58,191	3,520,520
Total lease commitments	5,584,370	126,680	5,711,050
Less imputed interest	1,927,257	41,271	1,968,528
Total lease liabilities	$ 3,657,113	$ 85,409	$ 3,742,522

We recognize lease assets and liabilities upon lease commencement. As of June 30, 2025, 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 $11.5 billion over the terms of the agreements. These arrangements primarily relate to energy storage PPA assets. We expect lease commencement dates ranging from July 2025 through June 2028, with lease terms expiring through June 2048. The lease commencement dates for certain arrangements have experienced delays. As a result of these delays and other events, APS has received cash proceeds from certain lessors prior to lease commencement. Proceeds received from lessors relating to energy storage PPA leases are accounted for as lease incentives on our Condensed Consolidated Balance Sheets, and upon lease commencement are amortized over the associated lease term. For regulatory purposes, the proceeds received by APS relating to these PPA leases are treated as a reduction to fuel and purchased power costs through the PSA in the period proceeds are received. See Note 6.

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

	Six Months Ended June 30,	
	2025	2024
Cash paid for amounts included in the measurement of lease liabilities — operating cash flows:	$ 60,813	$ 18,278
Right-of-use operating lease assets obtained in exchange for operating lease liabilities:	$ 2,071,145 (a)	$ 309,141

	June 30, 2025	December 31, 2024
Weighted average remaining lease term	16 years	11 years
Weighted average discount rate (b)	5.47 %	4.90 %

(a) Primarily relates to various new energy storage PPA operating leases, that have commenced in 2025.
(b) 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.

17. 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.

Assuming Treasury guidance is not released prior to October 15, 2025, the Company intends to first claim the Nuclear PTC on its 2024 tax return using a revenue requirement methodology to determine its gross receipts from nuclear sales. However, management believes that there remains uncertainty as to whether the IRS will ultimately agree with the use of this methodology. As such, the Company has not recognized any income tax benefits related to the Nuclear PTC as of June 30, 2025.

18. Sale of Bright Canyon Energy

On August 4, 2023, Pinnacle West entered into a purchase and sale agreement pursuant to which we agreed to sell all of our equity interest in our wholly-owned subsidiary, BCE. The BCE Sale was accounted for as the sale of a business and was structured to close in multiple stages that were completed on January 12, 2024. Certain investments and assets that BCE previously held, including the TransCanyon joint venture and holdings in the two Tenaska wind farm investments, were not included in the BCE Sale and were instead transferred to PNW Power, a wholly-owned subsidiary of Pinnacle West. The BCE Sale did not include a $31 million equity bridge loan relating to BCE’s Los Alamitos project, which was paid in full by Pinnacle West on August 4, 2023. Other than these retained investments and the debt instrument, all BCE assets and liabilities were included in the BCE Sale and were transferred to Ameresco.

The total carrying value of net assets transferred to Ameresco as a result of the BCE Sale was $79 million, with total consideration received by Pinnacle West of $108 million, resulting in a total pre-tax gain of $29 million, which was recognized between August 4, 2023 and January 12, 2024. The net assets transferred included $41 million of liabilities that have been assumed by Ameresco. The consideration received by Pinnacle West included both cash and interest-bearing promissory notes. The stages of the BCE Sale and timing of net assets transferring to Ameresco and related gain recognition are as follows:

- The first stage of the BCE Sale was completed on August 4, 2023. In the first stage, the net assets transferred to Ameresco totaled $44 million, which included a $36 million construction term loan. The assets and liabilities transferred in the first stage related to the BCE Los Alamitos project and were previously primarily classified as construction work in progress and current maturities of long-term debt, respectively. A gain of $6 million was recognized on our Consolidated Statements of Income for the year ended December 31, 2023, relating to the first stage of the BCE Sale.

- The final stage of the BCE Sale was completed on January 12, 2024. In the final stage, the net assets transferred to Ameresco totaled $35 million. The assets transferred in the final stage related primarily to equity method investments in the Kūpono Solar Project and other development stage projects. Our Consolidated Statements of Income for the year ended 2024, included a $23 million gain relating to the final stage of the BCE Sale.

As of January 12, 2024, all stages of the BCE Sale had been completed. As of December 31, 2024 the interest-bearing promissory note had been paid in full.

On January 30, 2024, Pinnacle West entered into a tax credit transfer agreement to purchase from Ameresco $23 million of investment tax credits from the BCE Los Alamitos project for $21 million.

Additionally, Pinnacle West continues to maintain certain guarantees relating to the Kūpono Solar Project sale-leaseback financing, which were not transferred in the BCE Sale transaction. See Note 10.

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 2024 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 $29 billion. Since 1886, Pinnacle West and our affiliates have provided energy and energy-related products to people and businesses throughout Arizona.

Pinnacle West derives essentially all of our revenues and earnings from our principal subsidiary, APS. APS is Arizona's largest and longest-serving electric company that generates safe, affordable and reliable electricity for approximately 1.4 million retail customers in 11 of Arizona's 15 counties. APS is also the operator and co-owner of Palo Verde Generating Station ("Palo Verde") — a primary source of electricity for the southwestern United States.

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 secure resource adequacy, planning and procuring resources to ensure sufficient reserve margins, 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. In the most recent all-source request for proposal ("ASRFP"), APS contracted for 3,606 MW of battery storage, 517 MW of natural gas, 2,649 MW of solar, and 500 MW of wind resources. APS regularly evaluates the best mix of resources based on a changing operating environment, including changes in generation technology, economics, and policy impacts.

There is a need for additional natural gas to support reliability for customers and meet increasing energy needs and existing natural gas pipelines into Arizona are currently 100% committed. As a result, in July 2025, APS executed a gas transportation precedent agreement to secure a long-term supply of natural gas. The new pipeline is expected to be operational by late 2029 and will be owned and operated by a third-party.

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 annually – 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. For Unit 2, APS currently leases nearly 12.1% through three separate sale-leaseback agreements, which have lease terms ending in 2033. In June 2025, APS entered into agreements to purchase two of the three leased interests, representing approximately 7%, or 94 MW, of Unit 2, subject to customary closing conditions, including approval by FERC. See Note 8 for more information. The 2025 Rate Case (as defined below) includes pro forma adjustments to account for these acquisitions. APS continues to evaluate and pursue options for reliably serving growing customer energy needs and demand.

Wildfire Efforts. As discussed above, 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 mitigating the risk associated with trees that could cause hazards, resulting in more of these trees being removed before they could cause outages or wildfires. These programs contribute to customer reliability, responsible forest management and safe communities. With wildfire events in Hawaii, California, and across 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 our 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 the additional real-time analysis provided by 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 the U.S. Department of Energy's ("DOE") 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, Arizona

Governor Hobbs 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. 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. In recent months, inflationary impacts have eased, with the CPI-U growing 2.7% nationally and 0.2% in Phoenix over the 12 months ended June 2025. However, APS remains cautious of potential price increases as a result of current and proposed tariffs, which could lead to higher costs and supply chain constraints.

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. 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 in the 2025 Rate Case. APS continues to seek opportunities to streamline its business processes, mitigate cost increases, increase employee retention, and improve customer satisfaction.

APS's Integrated Resource Plan ("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. See "Resource Planning" below for more information.

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 Southwest Power Pool ("SPP"). 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 October 2027. In addition, APS is participating in the Western Resource Adequacy Program administered by Western Power Pool and plans to transition to full-binding participation as early as summer 2027. These regional efforts are driven by the objectives of reducing customer cost and improving reliability. Until the transition to Markets+, APS will continue to participate in Western Energy Imbalance Market ("WEIM") as a tool for creating savings for APS's customers from the real-time only, voluntary market. APS expects that its participation in 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

In 2020, APS announced a goal to deliver 100% clean, carbon-free electricity to customers by 2050, driven by a trajectory of increasingly clean energy technologies such as solar power and energy storage, carbon-free nuclear operations, and advances in energy efficiency solutions. This goal included interim targets of a resource mix that was 65% clean by 2030, with 45% of that total coming from renewable energy, and an exit from coal-fired generation by 2031.

As Arizona’s population and economy continue to grow at record levels, so does its need for electricity. As a result, APS is updating its clean energy goals from an aspirational “zero-carbon” approach to an aspirational “carbon-neutral” approach by 2050. This means that for any greenhouse gas emissions still produced by our generation resources as of 2050, we will aim to offset these emissions elsewhere. This goal retains APS’s interest in new innovation and market transformations that address carbon emissions. APS is also removing its interim targets to better reflect APS’s near-term need to ensure reliability and affordability, while relying on the Integrated Resource Plan (“IRP”) process to help determine the most responsible path forward. 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 dispatchable resources, such as gas and the potential extension of coal beyond 2031.

APS has a diverse portfolio of existing and planned resources, including biomass, biogas, coal, energy storage, geothermal, natural gas, nuclear, solar, and wind. Maintaining a balanced and diverse portfolio of resources will ensure continued reliable service to our customers in the most affordable manner possible. Every three years, APS performs a comprehensive study, called an IRP, 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. To help ensure competitive costs for resources procured by APS, APS regularly issues competitive bid solicitations through the all-source request for proposal (“ASRFP”) process, with the most recent ASRFP being issued in 2024. 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. Under current market conditions, APS must aggressively contract for resources that can withstand supply chain and other geopolitical pressures. 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.

On June 30, 2023, APS issued an ASRFP (the “2023 ASRFP”) pursuant to which APS procured 3,606 MW of battery storage, 517 MW of natural gas, 2,649 of solar, and 500 MW of wind resources expected to be in service from 2026 to 2028.

On November 20, 2024, APS issued an ASRFP (the "2024 ASRFP") seeking 2,000 MW of resources. APS is seeking projects that can reach commercial operation beginning June 1, 2028 through June 1, 2030 but will consider projects that may achieve commercial operation as early as 2026. Additionally, APS is interested in projects that require longer planning, permitting, and construction and can be commercially operational after June 1, 2030. Bids for the 2024 ASRFP were due on February 5, 2025.

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 75% of customer calls within 30 seconds, and our mobile platforms enable our more than one million 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 recently introduced a high-bill analyzer tool enabling phone advisors to provide customers with specific, customized guidance based on their actual usage and habits.

Additionally, APS offers a customer assistance program, including up to a 60% bill discount for vulnerable customers, flexible payment arrangements, and emergency utility bill assistance. To ensure customers in need are connected to these programs, we partner with more than one hundred community action agencies across our service territory to train representatives who serve our shared customers.

Developing Technologies

New Nuclear Generation. APS, along with other Arizona electric utilities, 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, such as small modular nuclear reactors ("SMRs"). SMRs 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 utilities have applied for a grant from the DOE to begin preliminary exploration of a potential site for additional nuclear energy for Arizona. The grant could support a three-year site selection process and possible preparation of an early site permit application to United States Nuclear Regulatory Commission ("NRC").

Carbon Capture. Carbon Capture Utilization and Storage ("CCUS") technologies can isolate CO_2 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. CCUS technologies are still in the demonstration phase and while they show promise, they are still being tested in real-world conditions. These technologies could offer the potential to keep in operation existing generators that otherwise would need to be retired. APS will continue to monitor this emerging technology.

Artificial Intelligence. To address the rapid advancement of artificial intelligence ("AI") technology risks and opportunities, APS has developed an AI strategy that responsibly utilizes AI to advance our business strategy, enhance customer and employee experiences, and optimize operational reliability. At the core of our AI strategy is a robust governance model that develops guidance, policies, and relevant sub-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 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 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 "Formula Rate Adjustment Mechanism" ("FRAM") to assist with reducing regulatory lag and allow for rate gradualism;
- elimination of the Lost Fixed Cost Recovery Adjustment Mechanism ("LFCR") following the first annual adjustment pursuant to the FRAM; and
- modification to the System Reliability Benefit Mechanism ("SRB") due to the Formula Rate Adjustment Mechanism proposal.

APS requested that the increase become effective in the second half of 2026. The hearing for this rate case is currently scheduled to begin in May 2026. 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 Recommended Opinion and Order ("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 Demand Side Management ("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 CCT 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 Commission's December 17, 2024 decision on the rehearing. The Commission has taken no action on these requests. In addition, each of these parties have subsequently filed an appeal to the Arizona Court of Appeals seeking review of the ACC's decisions regarding the GAC and on rehearing. APS cannot predict the outcome of these proceedings.

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, the Residential Utility Consumer Office

("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 Arizona. 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 have also filed a Petition for Special Action with the Arizona Court of Appeals, requesting the case be sent back to the Superior Court for expedited consideration of the merits. APS cannot predict the outcome of this matter.

Cholla ACC Deferral Request

On August 14, 2024, APS filed a request with the ACC for a deferral order associated with unrecovered book value and closure costs of Cholla Units 1 and 3. This order would authorize APS to defer, for future recovery in rates, both the expenses necessary to close and decommission coal-fired power plant infrastructure at Cholla, including legally required site environmental remediation, coal combustion residuals ("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.

Fire Mitigation ACC Deferral Request

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.

See Note 6 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"). The Captive provides insurance coverage to Pinnacle West and our subsidiaries that supplements third-party insurance policies. 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 8. The Captive may hold investment assets in cash, cash equivalents, and equity and fixed income instruments.

Tax Incentives

The Inflation Reduction Act of 2022 ("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 Production Tax Credit ("PTC") in lieu of the Investment Tax Credit ("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 PTC for nuclear energy produced by existing nuclear energy plants, 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 projects which are currently under construction will continue to qualify for IRA tax credits. 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

On August 4, 2023, Pinnacle West entered into a purchase and sale agreement pursuant to which we agreed to sell all of our equity interest in our wholly-owned subsidiary Bright Canyon Energy Corporation ("BCE") to Ameresco (the "BCE Sale"). The transaction was accounted for as the sale of a business and closed in multiple stages. The final closing of the BCE Sale was completed on January 12, 2024. Certain investments and assets that BCE previously held, including the TransCanyon joint venture and holdings in the two Tenaska wind farm investments, were not included in the BCE Sale and were instead transferred to Pinnacle West Power, LLC ("PNW Power"), a wholly-owned subsidiary of Pinnacle West.

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. The DOE's GDO selected TransCanyon to enter into capacity contract negotiations for up to 25% of the Cross-Tie 500-kilovolt transmission line ("Cross-Tie") as part of the Transmission Facilitation Program. The agreement was executed on June 12, 2024. The proposed Cross-Tie project 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.

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 power purchase agreements. PNW Power indirectly owns 9.9% of Clear Creek and 5.1% of Nobles 2.

El Dorado Investment Company ("El Dorado")

El Dorado is a wholly-owned subsidiary of Pinnacle West. El Dorado owns debt investments and minority interests in several energy-related investments and Arizona community-based ventures. In particular, El Dorado has committed to and/or holds the following:

- $25 million investment in the Energy Impact Partners fund, of which approximately $19.5 million has been funded as of June 30, 2025. Energy Impact Partners is an organization that focuses on fostering innovation and supporting the transformation of the utility industry.

- $25 million investment in AZ-VC (formerly invisionAZ Fund), of which approximately $14.3 million has been funded as of June 30, 2025. AZ-VC 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 $1.2 million has been funded as of June 30, 2025. Westly Seed Fund is focused on supporting entrepreneurs involved in the energy, mobility, building, and industrial sectors.

- Equity investment in SAI Advanced Power Solutions ("SAI"), a private corporation that manufactures electrical switchgear equipment used by data centers. El Dorado accounts for this investment under the equity method, with a June 30, 2025 investment carrying value of $18.6 million. El Dorado has no further funding commitments to SAI.

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 the years 2022 through 2024, retail electric revenues averaged approximately 92% 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 Power Supply Adjustor ("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 2.4% for the period ended June 30, 2025 compared with the prior-year period. For the three years through 2024, APS's customer growth averaged 2.1% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2025 and the average annual growth to be in the range of 1.5% to 2.5% through 2027 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 3.8% for the period ended June 30, 2025 compared with the prior-year period. While steady customer growth was somewhat offset by lower usage among residential customers, energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives, the main drivers of increased revenues for this period were continued strong sales to commercial and industrial customers and the continued ramp-up of new data center and large manufacturing customers. As extra high load factor customers, such as data centers and large manufacturers, have continued to grow as a proportion of our business, we have updated our procedures with respect to estimates of unbilled revenues for our customer classes. As a result, we have made an adjustment in the first quarter of 2025 to recalibrate accrued unbilled revenues, offsetting year-to-date sales growth by 0.9%. Even with this offset to sales growth in the first quarter, we do not anticipate any change to our expected range of sales growth for the full year 2025.

For the three years through 2024, annual retail electricity sales growth averaged 3.2%, 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 2025 and that average annual growth will be in the range of 4.0% to 6.0% through 2027, including the effects of customer conservation, energy efficiency, and distributed renewable generation initiatives, 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 2025 growth in the range of 3.0% to 5.0% and to average annual growth in the range of 3.0% to 5.0% through 2027.

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 now receiving unprecedented incremental requests for service from extra high load factor customers (over 25 MW) with very high energy demands that persist virtually around-the-clock. These incremental requests for service by extra high load factor customers far exceed available generation and transmission resource capacity in the Southwest region for the foreseeable future. In April 2023, APS notified prospective extra high load factor customers without existing commitments from APS that it is not able to commit at this time to future extra large projects of over 25 MW. Because of the high growth in demand for such projects, APS has developed a prioritization queue that identifies and prioritizes projects while maintaining system reliability and affordability for existing APS customers. APS is exploring available options for securing sufficient electric generation and transmission to meet these projections of future customer needs.

Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as economic conditions, customer growth, usage patterns and energy conservation, 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 distributed generation, 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 $24 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 $6 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 $20 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, the mortality assumptions and the assumed healthcare cost trend rates. We review these assumptions on an annual basis and adjust them, as necessary. See Note 7.

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 9.7% of the assessed value for 2024, 10.0% for 2023, and 10.2% for 2022.

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 allowance for funds used during construction ("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 5 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. An allowance for borrowed funds used during construction offsets a portion of interest expense while capital projects are under construction. We stop accruing AFUDC on a project when it is placed 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, 2025, compared with three-month period ended June 30, 2024.

Our consolidated net income attributable to common shareholders for the three months ended June 30, 2025 was $193 million, compared with consolidated net income attributable to common shareholders of $204 million for the prior-year period. The results reflect a decrease of approximately $11 million, primarily as a result of the effects of weather, higher operations and maintenance expenses, lower pension and other postretirement non-service credits, net, higher depreciation and amortization expenses mostly due to increased plant additions and intangible assets, partially offset by Cholla plant retirement impacts, higher interest charges, and higher income taxes due to lower tax credits, partially offset by lower pre-tax income. These negative factors were partially offset by the favorable impacts of higher transmission service revenues, increased customer usage and growth, higher AFUDC, and higher other income due to investment gains in El Dorado.

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,		
	2025	2024	Net Change	2025	2024	Net Change
Operating revenues	$ 1,359	$ 1,309	$ 50	$ 1,359	$ 1,309	$ 50
Fuel and purchased power expenses	(477)	(437)	(40)	(477)	(437)	(40)
Operating revenues less fuel and purchased power expenses (a)	882	872	10	882	872	10
Operations and maintenance	(287)	(272)	(15)	(285)	(273)	(12)
Depreciation and amortization	(229)	(225)	(4)	(229)	(225)	(4)
Taxes other than income taxes	(58)	(59)	1	(58)	(59)	1
Pension and other postretirement non-service credits, net	4	13	(9)	4	13	(9)
Allowance for equity funds used during construction	15	9	6	15	9	6
Other income and (expense), net	7	—	7	(2)	—	(2)
Interest charges, net of allowance for borrowed funds used during construction	(102)	(98)	(4)	(80)	(82)	2
Income taxes	(35)	(32)	(3)	(39)	(39)	—
Less: income related to noncontrolling interests	(4)	(4)	—	(4)	(4)	—
Net Income Attributable to Common Shareholders	$ 193	$ 204	$ (11)	$ 204	$ 212	$ (8)

(a) Operating revenues less fuel and purchased power expenses 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 expenses as presented on the Condensed Consolidated Statements of Income. Operating revenues, less fuel and purchased power expenses 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 $10 million higher for the three months ended June 30, 2025 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 expenses**	**Net change**
Higher retail revenue due to changes in usage patterns and customer growth partially offset by the impacts of energy efficiency and related pricing	$ 28	$ 15	$ 13
Effects of weather	(33)	(9)	(24)
Higher renewable energy regulatory surcharges, partially offset by operations and maintenance costs	3	2	1
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	35	32	3
Higher transmission revenues (Note 6)	15	—	15
LFCR revenue (Note 6)	2	—	2
Total	$ 50	$ 40	$ 10

Operations and maintenance. Operations and maintenance expenses increased $15 million for the three months ended June 30, 2025 compared with the prior-year period primarily due to:

- an increase of $12 million related to corporate resource costs;
- an increase of $6 million related to information technology costs;
- an increase of $1 million related to non-nuclear generation costs, primarily due to higher planned outage;
- a decrease of $2 million related to nuclear generation costs;
- a decrease of $2 million related to transmission, distribution, and customer service costs;
- a decrease of $3 million related to employee benefit costs; and
- an increase of $3 million for other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $4 million higher for the three months ended June 30, 2025 compared to the prior-year period, primarily due to increased plant in service and intangible assets, partially offset by lower depreciation expense related to the Cholla plant retirement.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $9 million lower for the three months ended June 30, 2025 compared to the prior-year period, primarily due to prior-service credits becoming fully amortized as of January 31, 2025.

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 $2 million lower for the three months ended June 30, 2025 compared to the prior-year period, primarily due to higher allowance for equity funds, partially offset by higher debt balances.

Other income and expense, net. Other income and expense, net were $7 million higher for the three months ended June 30, 2025, compared to the prior-year period, primarily due to investment gains in El Dorado, partially offset by lower PSA interest income. The difference between APS's and Pinnacle West's other income and expense, net, is primarily related to Pinnacle West's investment gain in El Dorado.

Income taxes. Income taxes were $3 million higher for the three months ended June 30, 2025 compared with the prior-year period, primarily due to a one-time benefit recognized in the second quarter of 2024 related to the Los Alamitos ITC purchase, partially offset by lower pre-tax income.

Operating Results – Six-month period ended June 30, 2025, compared with six-month period ended June 30, 2024.

Our consolidated net income attributable to common shareholders for the six months ended June 30, 2025 was $188 million, compared with consolidated net income attributable to common shareholders of $221 million for the prior-year period. The results reflect a decrease of approximately $33 million, primarily as a result of higher operations and maintenance expenses, higher depreciation and amortization expenses mostly due to increased plant additions and intangible assets, partially offset by Cholla plant retirement impacts, the effects of weather, lower pension and other postretirement non-service credits, net, higher interest charges, net of AFUDC, and and the gain on the sale of BCE recognized during the first quarter of 2024. These negative factors were partially offset by the impacts of new customer rates, higher transmission service revenues, customer growth and increased usage, lower income taxes due to lower pretax income, higher tax benefits related to employee benefits, partially offset by lower tax credits, and investment gains in El Dorado.

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

	Pinnacle West Consolidated			APS Consolidated		
	Six Months Ended June 30,			Six Months Ended June 30,		
	2025	2024	Net Change	2025	2024	Net Change
	(dollars in millions)					
Operating revenues	$ 2,391	$ 2,261	$ 130	$ 2,391	$ 2,261	$ 130
Fuel and purchased power expenses	(857)	(795)	(62)	(857)	(795)	(62)
Operating revenues less fuel and purchased power expenses (a)	1,534	1,466	68	1,534	1,466	68
Operations and maintenance	(587)	(530)	(57)	(582)	(526)	(56)
Depreciation and amortization	(464)	(435)	(29)	(464)	(435)	(29)
Taxes other than income taxes	(117)	(118)	1	(117)	(118)	1
Pension and other postretirement non-service credits, net	7	24	(17)	7	25	(18)
Allowance for equity funds used during construction	28	19	9	28	19	9
Other income and (expense), net	22	24	(2)	2	3	(1)
Interest charges, net of allowance for borrowed funds used during construction	(197)	(184)	(13)	(159)	(156)	(3)
Income taxes	(29)	(36)	7	(36)	(42)	6
Less: income related to noncontrolling interests	(9)	(9)	—	(9)	(9)	—
Net Income Attributable to Common Shareholders	$ 188	$ 221	$ (33)	$ 204	$ 227	$ (23)

(a) Operating revenues less fuel and purchased power expenses 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 expenses as presented on the Condensed Consolidated Statements of Income. Operating revenues, less fuel and purchased power expenses 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 $68 million higher for the six months ended June 30, 2025 compared with the prior-year period. The following table summarizes the major components of this change:

	Increase (Decrease)		
	Operating revenues	Fuel and purchased power expenses	Net change
	(dollars in millions)		
Impact of new rates from the 2022 Rate Case, effective March 8, 2024 (Note 6)	$ 46	$ —	$ 46
Higher retail revenue due to changes in customer growth and usage patterns partially offset by the impacts of energy efficiency and related pricing	33	19	14
Effects of weather	(33)	(9)	(24)
LFCR revenue (Note 6)	6	—	6
Higher renewable energy regulatory surcharges, partially offset by operations and maintenance costs	5	4	1
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	49	49	—
Higher transmission revenues (Note 6)	21	—	21
Miscellaneous items, net	3	(1)	4
Total	$ 130	$ 62	$ 68

Operations and maintenance. Operations and maintenance expenses increased $57 million for the six months ended June 30, 2025 compared with the prior-year period, primarily due to:

- an increase of $19 million related to information technology costs;
- an increase of $18 million related to non-nuclear generation costs, primarily due to increased planned outages;
- an increase of $16 million related to corporate resource costs;
- an increase of $4 million related to transmission, distribution, and customer service costs;
- a decrease of $3 million related to employee benefit costs;
- an increase of $3 million for other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $29 million higher for the six months ended June 30, 2025 compared to the prior-year period, primarily due to increased plant in service and intangible assets, partially offset by lower depreciation expense related to the Cholla plant retirement.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $17 million lower for the six months ended June 30, 2025 compared to the prior-year period primarily, due to prior-service credits becoming fully amortized as of January 31, 2025.

Other income and expense, net. Other income and expense, net were $2 million lower for the six months ended June 30, 2025 compared to the prior-year period, primarily due to the gain on the sale of

BCE recognized during the first quarter of 2024 and lower PSA interest income, partially offset by investment gains in El Dorado. The difference between APS's and Pinnacle West's other income and expense, net is primarily related to Pinnacle West's gain on the sale of BCE and the gain in investment in 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 $4 million higher for the six months ended June 30, 2025 compared to the prior-year period, primarily due to higher debt balances and higher allowance for borrowed funds, partially offset by higher allowance for equity funds.

Income taxes. Income taxes were $7 million lower for the six months ended June 30, 2025 compared with the prior-year period, primarily due to lower pre-tax income and higher tax benefits related to employee benefits.

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, 2025, APS's common equity ratio, as defined, was 54%. Its total shareholder equity was approximately $8.6 billion, and total capitalization, as calculated pursuant to the ACC order, was approximately $15.9 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $6.4 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. 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 loan 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. 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.

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 2029.

Pinnacle West has an at-the-market equity distribution program (the "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. As of June 30, 2025, approximately $800 million of common stock is available to be issued under the ATM Program, which takes into account the forward sale agreements in effect as of June 30, 2025. Pinnacle West also has forward sale agreements from an equity offering in February 2024 in effect as of June 30, 2025. See "Financing Cash Flows and Liquidity—Equity Offerings" below and Note 12 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,		
	2025	2024	Net Change
Net cash flow provided by operating activities	$ 663	$ 537	$ 126
Net cash flow used for investing activities	(1,253)	(887)	(366)
Net cash flow provided by financing activities	605	349	256
Net increase (decrease) in cash and cash equivalents	$ 15	$ (1)	$ 16

APS

	Six Months Ended June 30,		
	2025	2024	Net Change
Net cash flow provided by operating activities	$ 698	$ 573	$ 125
Net cash flow used for investing activities	(1,248)	(932)	(316)
Net cash flow provided by financing activities	561	358	203
Net increase (decrease) in cash and cash equivalents	$ 11	$ (1)	$ 12

Operating Cash Flows

Six-month period ended June 30, 2025, compared with six-month period ended June 30, 2024. Pinnacle West's consolidated net cash provided by operating activities was $663 million in 2025 compared to $537 million in 2024, an increase of $126 million in net cash provided, primarily due to $185 million higher cash receipts from electric revenues, $17 million lower income taxes and $14 million lower payments for operations and maintenance costs; partially offset by $59 million higher fuel and purchased power costs, $12 million higher other taxes paid, $12 million in higher interest paid on debt and $7 million of 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. Under ERISA, the qualified pension plan was 101% funded as of January 1, 2025, and was 113% funded as of January 1, 2024. 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 and we do not expect to make any voluntary cash contributions in 2025, 2026 or 2027. Regarding contributions to our other postretirement benefit plan, we have not made a contribution year-to-date in 2025 and do not expect to make any contributions in 2025, 2026 or 2027. 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. For instance, our pension plan's funded status, as measured for accounting principles generally accepted in the United States of America ("GAAP") purposes, was 99% funded as of December 31, 2024, and our postretirement benefit plans were 195% funded, as measured by GAAP at December 31, 2024.

Investing Cash Flows

Six-month period ended June 30, 2025, compared with six-month period ended June 30, 2024. Pinnacle West's consolidated net cash used for investing activities was $1,253 million in 2025 compared to $887 million in 2024, an increase of $366 million primarily related to $317 million of increased capital expenditures, net of contributions in aid of construction, and $48 million of proceeds from the BCE Sale received in 2024. See "Capital Expenditures" for additional details. The difference between APS's and Pinnacle West's net cash used for investing activities primarily relates to the BCE Sale.

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

Capital Expenditures

	Estimated for the Year Ended December 31,		
	2025	**2026**	**2027**
APS			
Generation:			
Nuclear Generation	$ 150	$ 165	$ 185
Renewables and Energy Storage Systems ("ESS")	335	165	430
Other Generation (a)	420	540	335
Distribution	665	670	675
Transmission	450	675	750
Other	380	335	275
Total APS	$ 2,400	$ 2,550	$ 2,650

(a) Includes gas generation and environmental projects.

The table above does not include capital expenditures related to PNW Power projects or the pending purchase of certain leased interests relating to Palo Verde. See Note 8.

Generation capital expenditures are comprised of various additions and improvements to APS's resources, including nuclear plants, renewables and ESS, as well as additions and improvements to existing fossil fuel plants. 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, 2025, compared with six-month period ended June 30, 2024. Pinnacle West's consolidated net cash provided by financing activities was $605 million in 2025 compared to $349 million in 2024, an increase of $256 million in net cash provided primarily due to a net increase of $915 million in short-term borrowings; partially offset by a net decrease of $643 million in long term debt borrowings.

APS's consolidated net cash provided by financing activities was $561 million in 2025 compared to $358 million in 2024, an increase of $203 million in net cash provided primarily due to a net increase of $863 million in short-term borrowings; partially offset by a net decrease of $496 million in long term debt borrowings and $150 million in lower equity infusions from Pinnacle West.

Significant Financing Activities. On June 18, 2025, the Pinnacle West Board of Directors declared a dividend of $0.895 per share of common stock, payable on September 2, 2025, to shareholders of record on August 1, 2025.

On May 15, 2025, Pinnacle West contributed $300 million into APS in the form of an equity infusion. APS used this contribution to repay the $300 million of 3.15% senior notes that matured on the same date.

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 5 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. See Note 12. The following table summarizes the activity relating to these forward sale agreements and the ATM Program as of June 30, 2025 (in thousands, except share amounts and price per share):

	As of June 30, 2025		
	February 2024 Forward Sale Agreements	November 2024 ATM Forward Sale Agreement	March 2025 ATM Forward Sale Agreement
Initial Price			
Number of Shares	11,240,601	552,833	544,959
Forward Sales Price Per Share (a)	$ 64.51	$ 89.73	$ 90.83
Aggregate Value (in thousands)	$ 725,131	$ 49,606	$ 49,499
Settlements			
Date	12/23/2024		
Number of Shares Settled (b)	5,377,115	—	—
Forward Sales Price Upon Settlement	$ 64.17	$ —	$ —
Net Proceeds (in thousands) (c)	$ 345,049	$ —	$ —

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

Other Financing Matters. See Note 9 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, 2025, the ratio was approximately 61% for Pinnacle West and 50% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could "cross-default" other debt. See further discussion of "cross-default" provisions below.

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

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

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.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of July 28, 2025, 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 cash obligations have not materially changed during the six months ended June 30, 2025 as compared to the 2024 Form 10-K, except as disclosed in Note 5 - "Debt and Liquidity Matters", Note 8 - " Variable Interest Entities", and Note 10 - "Commitments and Contingencies" to the 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 2024 Form 10-K. See "Critical Accounting Policies and Estimates" in Item 7 of the 2024 Form 10-K for further details about our critical accounting policies and estimates.

OTHER ACCOUNTING MATTERS

See Note 3 for information on the following new accounting standards that are pending adoption:

- ASU 2023-09, Income Taxes: Improvements to Income Tax Disclosures, effective for us on December 31, 2025.
- ASU 2024-03, Income Statement Reporting: Expense Disaggregation Disclosures, effective for us on December 31, 2027.
- ASU 2025-03, Business Combinations and Consolidation: Determining the Accounting Acquirer in the Acquisition of a Variable Interest Entity, effective for us on January 1, 2027.

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 13 and 14), 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,	
	2025	2024
Balance at beginning of period	$ (42)	$ (120)
Decrease (increase) in regulatory asset	59	(2)
Balance at end of period	$ 17	$ (122)

The table below shows the fair value of maturities of our energy derivative contracts (dollars in millions) as of June 30, 2025, 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 2024 Form 10-K for more discussion of our valuation methods.

Source of Fair Value	2025	2026	2027	2028	2029	Total Fair Value
Observable prices provided by other external sources	$ (7)	$ 31	$ 10	$ 2	$ —	$ 36
Prices based on unobservable inputs	(13)	(6)	—	—	—	(19)
Total by maturity	$ (20)	$ 25	$ 10	$ 2	$ —	$ 17

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, 2025 Gain (Loss)		December 31, 2024 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	$ 8	$ (8)	$ 3	$ (3)
Natural gas	73	(73)	75	(75)
Total	$ 81	$ (81)	$ 78	$ (78)

(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 9 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, 2025. 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, 2025. 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, 2025 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 2024 Form 10-K with regard to pending or threatened litigation and other matters.

See Note 6 for ACC and FERC-related matters.

See Note 10 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 2024 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 2024 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.

The risk factor below is an update to our 2024 Form 10-K.

The inability to successfully develop, acquire or operate generation resources to meet future resource needs and load forecasts in accordance with reliability requirements and other new or evolving standards and regulations could adversely impact our business.

Potential changes in regulatory standards, impacts of new and existing laws and regulations, including environmental laws and regulations, and the need to obtain various regulatory approvals create uncertainty surrounding our current and future generation portfolio. The current regulatory standards, laws, and regulations create strategic challenges as to the appropriate generation portfolio and fuel diversification mix. APS is required by the ACC to meet certain energy resource portfolio requirements, including those related to renewables development and energy efficiency measures, in addition to specific competitive resource procurement requirements. The development and operation of any generation facility is also subject to many risks, including those related to financing, siting, permitting, new and evolving technology, extreme weather events, workforce issues, cybersecurity attacks, supply chain constraints for critical spare parts, and the construction of sufficient transmission capacity to support these facilities among others. APS needs to develop or acquire new generation facilities, potentially modernize existing facilities, and/or contract for additional capacity in order to meet future resource needs and load forecasts. APS's inability to do so could have a material adverse impact on our business and results of operations.

In expressing concerns about the environmental and climate-related impacts from continued extraction, transportation, delivery and combustion of fossil fuels, environmental advocacy groups and other third parties have in recent years undertaken greater efforts to oppose the permitting, construction, and operation of fossil fuel infrastructure projects. These efforts may increase in scope and frequency depending on a number of variables, including the future course of Federal environmental regulation and the increasing financial resources devoted to these opposition activities. APS cannot predict the effect that any such opposition may have on our ability to develop, construct, and operate fossil fuel infrastructure projects in the future.

In August 2025, APS announced an update to its clean energy goals from a zero-carbon approach to a goal to be carbon-neutral by 2050. APS's ability to successfully execute its clean energy goal is dependent upon a number of external factors, some of which include supportive national and state energy policies, a supportive regulatory environment, sales and customer growth, the development, deployment and advancement of clean energy technologies, adequate supply chain for generation resources, and continued access to capital markets.

ITEM 5. OTHER INFORMATION

Rule 10b5-1 Trading Plans

During the fiscal quarter ended June 30, 2025, 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	Pinnacle West Articles of Incorporation, restated as of May 23, 2025		
3.2	Pinnacle West	Pinnacle West Capital Corporation Bylaws, amended as of February 19, 2020	3.1 to Pinnacle West/APS February 25, 2020 Form 8-K Report	2/25/2020
3.3	APS	APS Articles of Incorporation, restated as of May 16, 2012		
3.4	APS	Arizona Public Service Company Bylaws, amended as of December 16, 2008	3.4 to Pinnacle West/APS December 31, 2008 Form 10-K Report	2/20/2009

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, 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, 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, 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, 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 6, 2025

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 6, 2025

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