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, 2024 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 1-3701

AVISTA CORPORATION

(Exact name of Registrant as specified in its charter)

Washington	**91-0462470**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

1411 East Mission Avenue, Spokane, Washington 99202-2600
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: 509-489-0500

None

(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	AVA	New York Stock Exchange

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days: 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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

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

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act): Yes ☐ No ☒

As of August 2, 2024, 78,703,761 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

AVISTA CORPORATION
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ACRONYMS AND TERMS
(The following acronyms and terms are found in multiple locations within the document)

Acronym/Term		Meaning
aMW	-	Average Megawatt - a measure of the average rate at which a particular generating source produces energy over a period of time
AEL&P	-	Alaska Electric Light and Power Company, the primary operating subsidiary of AERC, which provides electric services in Juneau, Alaska
AERC	-	Alaska Energy and Resources Company, the Company's wholly-owned subsidiary based in Juneau, Alaska
AFUDC	-	Allowance for Funds Used During Construction; represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period
ASC	-	Accounting Standards Codification
ASU	-	Accounting Standards Update
Avista Capital	-	Parent company to the Company’s non-utility businesses, with the exception of AJT Mining Properties, Inc., which is a subsidiary of AERC.
Avista Corp.	-	Avista Corporation, the Company
Avista Utilities	-	Operating division of Avista Corp. (not a subsidiary) comprising the regulated utility operations in the Pacific Northwest
Capacity	-	The rate at which a particular generating source is capable of producing energy, measured in KW or MW
Cabinet Gorge	-	The Cabinet Gorge Hydroelectric Generating Project, located on the Clark Fork River in Idaho
CCA	-	Climate Commitment Act
CETA	-	Clean Energy Transformation Act
Colstrip	-	The coal-fired Colstrip Generating Plant in southeastern Montana
Cooling degree days	-	The measure of the warmness of weather experienced, based on the extent to which the average of high and low temperatures for a day exceeds 65 degrees Fahrenheit (annual degree days above historic indicate warmer than average temperatures)
COVID-19	-	Coronavirus disease 2019, a respiratory illness declared a pandemic in March 2020
Deadband or ERM deadband	-	The first $4.0 million in annual power supply costs above or below the amount included in base retail rates in Washington under the ERM in the state of Washington
EIM	-	Energy Imbalance Market
Energy	-	The amount of electricity produced or consumed over a period of time, measured in KWh or MWh. Also, refers to natural gas consumed and is measured in dekatherms
EPA	-	Environmental Protection Agency
ERM	-	The Energy Recovery Mechanism, a mechanism for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Washington
FASB	-	Financial Accounting Standards Board
FCA	-	Fixed Cost Adjustment, the electric and natural gas decoupling mechanism in Idaho
FERC	-	Federal Energy Regulatory Commission
GAAP	-	Generally Accepted Accounting Principles
GHG	-	Greenhouse gas
Heating degree days	-	The measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual degree days below historic indicate warmer than average temperatures).
IPUC	-	Idaho Public Utilities Commission

KW, KWh	-	Kilowatt (1000 watts): a measure of generating power or capability. Kilowatt-hour (1000 watt hours): a measure of energy produced over a period of time
MPSC	-	Public Service Commission of the State of Montana
MW, MWh	-	Megawatt: 1000 KW. Megawatt-hour: 1000 KWh
Noxon Rapids	-	The Noxon Rapids Hydroelectric Generating Project, located on the Clark Fork River in Montana
OPUC	-	The Public Utility Commission of Oregon
PCA	-	The Power Cost Adjustment mechanism, a procedure for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Idaho
PGA	-	Purchased Gas Adjustment
PPA	-	Power Purchase Agreement
RCA	-	The Regulatory Commission of Alaska
REC	-	Renewable energy credit
ROE	-	Return on equity
ROR	-	Rate of return on rate base
ROU	-	Right-of-use lease asset
SEC	-	U.S. Securities and Exchange Commission
SOFR	-	Secured Overnight Financing Rate
Talen	-	Talen Montana, LLC, an indirect subsidiary of Talen Energy Corporation.
Therm	-	Unit of measurement for natural gas; a therm is equal to approximately one hundred cubic feet (volume) or 100,000 BTUs (energy)
Watt	-	Unit of measurement of electric power or capability; a watt is equal to the rate of work represented by a current of one ampere under a pressure of one volt
WUTC	-	Washington Utilities and Transportation Commission

Forward-Looking Statements

From time to time, we make forward-looking statements such as statements regarding projected or future:

- financial performance;
- cash flows;
- capital expenditures;
- dividends;
- capital structure;
- other financial items;
- strategic goals and objectives;
- business environment; and
- plans for operations.

These statements are based upon underlying assumptions (many of which are based, in turn, upon further assumptions). Such statements are made both in our reports filed under the Securities Exchange Act of 1934, as amended (including this Quarterly Report on Form 10-Q), and elsewhere. Forward-looking statements are all statements except those of historical fact including, without limitation, those identified by the use of words that include "will," "may," "could," "should," "intends," "plans," "seeks," "anticipates," "estimates," "expects," "forecasts," "projects," "predicts," and similar expressions.

Forward-looking statements (including those made in this Quarterly Report on Form 10-Q) are subject to a variety of risks, uncertainties and other factors. Most of these factors are beyond our control and may have a significant effect on our operations, results of operations, financial condition or cash flows, which could cause actual results to differ materially from those anticipated in our statements. Such risks, uncertainties and other factors include, among others:

Utility Regulatory Risk

- state and federal regulatory decisions or related judicial decisions that affect our ability to recover costs and earn a reasonable return including, but not limited to, disallowance or delay in the recovery of capital investments, operating costs, commodity costs, the ordering of refunds to customers and discretion over allowed return on investment;
- the loss of regulatory accounting treatment, which could require the write-off of regulatory assets and the loss of regulatory deferral and recovery mechanisms;

Operational Risk

- weather conditions, which affect both energy demand and electric generating capability, including the impact of precipitation and temperature on hydroelectric resources, the impact of wind patterns on wind-generated power, weather-sensitive customer demand, and similar impacts on supply and demand in the wholesale energy markets;
- wildfires ignited, or allegedly ignited, by our equipment or facilities could cause significant loss of life and property or result in liability for resulting fire suppression costs and/or damages, thereby causing serious operational, reputational and financial harm;
- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, extreme temperature events, snow and ice storms that could disrupt energy generation, transmission and distribution, as well as the availability and costs of fuel, materials, equipment, supplies and support services;
- political unrest and/or conflicts between foreign nation-states, which could disrupt the global, national and local economy, result in increases in operating and capital costs, impact energy commodity prices or our ability to access energy resources, create disruption in supply chains, disrupt, weaken or create volatility in capital markets, and increase cyber

and physical security risks. In addition, any of these factors could negatively impact our liquidity and limit our access to capital, among other implications;

- explosions, fires, accidents, mechanical breakdowns or other incidents that could impair assets and may disrupt operations of our generation facilities, transmission, and electric and natural gas distribution systems or other operations and may require us to purchase replacement power or incur costs to repair our facilities;
- interruptions in the delivery of natural gas by our suppliers, including physical problems with pipelines themselves, can disrupt our service of natural gas to our customers and/or impair our ability to operate gas-fired electric generating facilities;
- explosions, fires, accidents or other incidents arising from or allegedly arising from our operations that could cause injuries to the public or property damage;
- blackouts or disruptions of interconnected transmission systems (the regional power grid);
- terrorist attacks, cyberattacks or other malicious acts that could disrupt or cause damage to our utility assets or to the national or regional economy in general, including effects of terrorism, cyberattacks, ransomware, or vandalism that damage or disrupt information technology systems;
- pandemics, which could disrupt our business, as well as the global, national and local economy, resulting in a decline in customer demand, deterioration in the creditworthiness of our customers, increases in operating and capital costs, workforce shortages, losses or disruptions in our workforce due to vaccine mandates, delays in capital projects, disruption in supply chains, and disruption, weakness and volatility in capital markets. In addition, any of these factors could negatively impact our liquidity and limit our access to capital, among other implications;
- work-force issues, including changes in collective bargaining unit agreements, strikes, work stoppages, the loss of key executives, availability of workers in a variety of skill areas, and our ability to recruit and retain employees;
- changes in the availability and price of purchased power, fuel and natural gas, as well as transmission capacity;
- increasing costs of insurance, more restrictive coverage terms and our ability to obtain insurance;
- delays or changes in construction costs, and/or our ability to obtain required permits and materials for present or prospective facilities;
- increasing health care costs and cost of health insurance provided to our employees and retirees;
- increasing operating costs, including effects of inflationary pressures;
- third party construction of buildings, billboard signs, towers or other structures within our rights of way, or placement of fuel containers within close proximity to our transformers or other equipment, including overbuilding atop natural gas distribution lines;
- the loss of key suppliers for materials or services or other disruptions to the supply chain;
- adverse impacts to our Alaska electric utility (AEL&P) that could result from an extended outage of its hydroelectric generating resources or their inability to deliver energy, due to their lack of interconnectivity to other electrical grids and the availability or cost of replacement power (diesel);
- changing river or reservoir regulation or operations at hydroelectric facilities not owned by us, which could impact our hydroelectric facilities downstream;

Climate Change Risk

- increasing frequency and intensity of severe weather or natural disasters resulting from climate change, that could disrupt energy generation, transmission and distribution, as well as the availability and costs of fuel, materials, equipment, supplies and support services;
- change in the use, availability or abundancy of water resources and/or rights needed for operation of our hydroelectric facilities, including impacts resulting from climate change;
- changes in the long-term climate and weather could materially affect, among other things, customer demand, the volume and timing of streamflows required for hydroelectric generation, costs of generation, transmission and distribution. Increased or new risks may arise from severe weather or natural disasters, including wildfires as well as their increased occurrence and intensity related to changes in climate;

Cybersecurity Risk

- cyberattacks on the operating systems used in the operation of our electric generation, transmission and distribution facilities and our natural gas distribution facilities, and cyberattacks on such systems of other energy companies with which we are interconnected, which could damage or destroy facilities or systems or disrupt operations for extended periods of time and result in the incurrence of liabilities and costs;
- cyberattacks on the administrative systems used in the administration of our business, including customer billing and customer service, accounting, communications, compliance and other administrative functions, and cyberattacks on such systems of our vendors and other companies with which we do business, resulting in the disruption of business operations, the release of private information and the incurrence of liabilities and costs;

Technology Risk

- changes in costs that impede our ability to implement new information technology systems or to operate and maintain current production technology;
- changes in technologies, possibly making some of the current technology we utilize obsolete or introducing new cyber security risks and other new risks inherent in the use, by either us or our counterparties, of new technologies in the developmental stage including, without limitation, generative artificial intelligence;
- changes in the use, perception, or regulation of generative artificial intelligence technologies, which could limit our ability to utilize such technology, create risk of enhanced regulatory scrutiny, generate uncertainty around intellectual property ownership, licensing or use, or which could otherwise result in risk of damage to our business, reputation or financial results;
- insufficient technology skills, which could lead to the inability to develop, modify or maintain our information systems;

Strategic Risk

- growth or decline of our customer base due to new uses for our services or decline in existing services, including, but not limited to, the effect of the trend toward distributed generation at customer sites;
- the potential effects of negative publicity regarding our business practices, whether true or not, which could hurt our reputation and result in litigation or a decline in our common stock price;
- changes in our strategic business plans, which could be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses and the extent of our business development efforts where potential future business is uncertain;

- wholesale and retail competition including alternative energy sources, growth in customer-owned power resource technologies that displace utility-supplied energy or may be sold back to the utility, and alternative energy suppliers and delivery arrangements;
- non-regulated activities may increase earnings volatility and result in investment losses;
- the risk of municipalization or other forms of service territory reduction;

External Mandates Risk

- changes in environmental laws, regulations, decisions and policies, including, but not limited to, regulatory responses to concerns regarding climate change, efforts to restore anadromous fish in areas currently blocked by dams, more stringent requirements related to air quality, water quality and waste management, present and potential environmental remediation costs and our compliance with these matters;
- the potential effects of initiatives, legislation or administrative rulemaking at the federal, state or local levels, including possible effects on our generating resources, prohibitions or restrictions on new or existing services, or restrictions on greenhouse gas emissions to mitigate concerns over climate changes, including future limitations on the usage and distribution of natural gas;
- political pressures or regulatory practices that could constrain or place additional cost burdens on our distribution systems through accelerated adoption of distributed generation or electric-powered transportation or on our energy supply sources, such as campaigns to halt fossil fuel-fired power generation and opposition to other thermal generation, wind turbines or hydroelectric facilities;
- failure to identify changes in legislation, taxation and regulatory issues that could be detrimental or beneficial to our overall business;
- policy and/or legislative changes in various regulated areas, including, but not limited to, environmental regulation, healthcare regulations and import/export regulations;

Financial Risk

- our ability to obtain financing through the issuance of debt and/or equity securities and access to our funds held with financial institutions, which could be affected by various factors including our credit ratings, interest rates, other capital market conditions and global economic conditions;
- changes in interest rates that affect borrowing costs, variable interest rate borrowing and the extent to which we recover interest costs through retail rates collected from customers;
- volatility in energy commodity markets that affect our ability to effectively hedge energy commodity risks, including cash flow impacts and requirements for collateral;
- volatility in the carbon emissions allowances market that could result in increased compliance costs;
- changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension and other postretirement benefit plans, which could affect future funding obligations, pension and other postretirement benefit expense and the related liabilities;
- the outcome of legal proceedings and other contingencies;
- economic conditions in our service areas, including the economy's effects on customer demand for utility services;
- economic conditions nationally may affect the valuation of our unregulated portfolio companies;

- declining electricity demand related to customer energy efficiency, conservation measures and/or increased distributed generation and declining natural gas demand related to customer energy efficiency, conservation measures and/or increased electrification;
- industry and geographic concentrations which could increase our exposure to credit risks due to counterparties, suppliers and customers being similarly affected by changing conditions;
- deterioration in the creditworthiness of our customers;
- activist shareholders may result in additional costs and resources required in response to activist actions;

Energy Commodity Risk

- volatility and illiquidity in wholesale energy markets, including exchanges, the availability of willing buyers and sellers, changes in wholesale energy prices that could affect operating income, cash requirements to purchase electricity and natural gas, value received for wholesale sales, collateral required of us by individual counterparties and/or exchanges in wholesale energy transactions and credit risk from such transactions, and the market value of derivative assets and liabilities;
- default or nonperformance on the part of parties from whom we purchase and/or sell capacity or energy;
- potential environmental regulations or lawsuits affecting our ability to utilize or resulting in the obsolescence of our power supply resources;
- explosions, fires, accidents, pipeline ruptures or other incidents that could limit energy supply to our facilities or our surrounding territory, which could result in a shortage of commodities in the market that could increase the cost of replacement commodities from other sources;

Compliance Risk

- changes in laws, regulations, decisions and policies at the federal, state or local levels, which could materially impact both our electric and gas operations and costs of operations; and
- the ability to comply with the terms of the licenses and permits for our hydroelectric or thermal generating facilities at cost-effective levels.

Our expectations, beliefs and projections are expressed in good faith. We believe they are reasonable based on, without limitation, an examination of historical operating trends, our records and other information available from third parties. There can be no assurance our expectations, beliefs or projections will be achieved or accomplished. Furthermore, any forward-looking statement speaks only as of the date on which such statement is made. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time to time, and it is not possible for us to predict all such factors, nor can we assess the effect of each such factor on our business or the extent any such factor or combination of factors may cause actual results to differ materially from those contained in any forward-looking statement.

Available Information

We file annual, quarterly and current reports and proxy statements with the SEC. The SEC maintains a website that contains these documents at www.sec.gov. We make annual, quarterly and current reports and proxy statements available on our website, https://investor.avistacorp.com, as soon as practicable after electronically filing these documents with the SEC. Except for SEC filings or portions thereof specifically referred to in this report, information contained on these websites is not part of this report.

PART I. Financial Information

Item 1. Condensed Consolidated Financial Statements

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Three and Six Months Ended June 30
Dollars in thousands, except per share amounts
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Operating Revenues:				
Utility revenues:				
Utility revenues, exclusive of alternative revenue programs	$ 385,861	$ 374,285	$ 992,372	$ 867,828
Alternative revenue programs	16,171	5,513	19,054	(13,525)
Total utility revenues	402,032	379,798	1,011,426	854,303
Non-utility revenues	40	139	62	265
Total operating revenues	402,072	379,937	1,011,488	854,568
Operating Expenses:				
Utility operating expenses:				
Resource costs	144,326	141,244	437,443	334,172
Other operating expenses	109,591	103,071	220,840	208,049
Depreciation and amortization	67,829	66,148	135,756	131,336
Taxes other than income taxes	25,710	24,917	61,398	58,811
Non-utility operating expenses	360	749	679	1,791
Total operating expenses	347,816	336,129	856,116	734,159
Income from operations	54,256	43,808	155,372	120,409
Interest expense	35,924	35,018	72,828	70,102
Interest expense to affiliated trusts	656	608	1,313	1,179
Capitalized interest	(1,145)	(866)	(2,106)	(1,708)
Other income-net	(4,532)	(2,626)	(13,817)	(9,055)
Income before income taxes	23,353	11,674	97,154	59,891
Income tax expense (benefit)	495	(5,810)	2,801	(12,438)
Net income	$ 22,858	$ 17,484	$ 94,353	$ 72,329
Weighted-average common shares outstanding (thousands), basic	78,390	75,983	78,276	75,576
Weighted-average common shares outstanding (thousands), diluted	78,456	76,131	78,333	75,703
Earnings per common share:				
Basic	$ 0.29	$ 0.23	$ 1.20	$ 0.96
Diluted	$ 0.29	$ 0.23	$ 1.20	$ 0.96

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

For the Three and Six Months Ended June 30
Dollars in thousands
(Unaudited)

	Three months ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Net income	$ 22,858	$ 17,484	$ 94,353	$ 72,329
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $0, ($5), ($2) and ($10), respectively	—	(19)	(9)	(37)
Comprehensive income	$ 22,858	$ 17,465	$ 94,344	$ 72,292

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands
(Unaudited)

	June 30, 2024	December 31, 2023
Assets:		
Current Assets:		
Cash and cash equivalents	$ 14,647	$ 35,003
Accounts and notes receivable-less allowances of $3,624 and $4,987, respectively	153,519	216,744
Inventory	175,588	159,984
Regulatory assets	130,389	146,327
Other current assets	76,717	103,784
Total current assets	550,860	661,842
Net utility property	5,827,143	5,700,056
Goodwill	52,426	52,426
Non-current regulatory assets	844,767	894,168
Other property and investments-net and other non-current assets	408,574	393,985
Total assets	$ 7,683,770	$ 7,702,477
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 104,620	$ 143,262
Current portion of long-term debt	15,000	15,000
Short-term borrowings	244,000	349,000
Regulatory liabilities	94,385	76,007
Other current liabilities	166,761	191,936
Total current liabilities	624,766	775,205
Long-term debt	2,598,398	2,515,358
Long-term debt to affiliated trusts	51,547	51,547
Pensions and other postretirement benefits	92,211	89,830
Deferred income taxes	718,728	718,318
Non-current regulatory liabilities	829,061	856,666
Other non-current liabilities and deferred credits	241,820	210,230
Total liabilities	5,156,531	5,217,154
Commitments and Contingencies (See Notes to Condensed Consolidated Financial Statements)		
Equity:		
Shareholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 78,702,117 and 78,074,587 shares issued and outstanding, respectively	1,666,692	1,644,327
Accumulated other comprehensive loss	(366)	(357)
Retained earnings	860,913	841,353
Total shareholders' equity	2,527,239	2,485,323
Total liabilities and equity	$ 7,683,770	$ 7,702,477

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

For the Six Months Ended June 30
Dollars in thousands
(Unaudited)

	2024	2023
Operating Activities:		
Net income	$ 94,353	$ 72,329
Non-cash items included in net income:		
Depreciation and amortization	135,761	131,367
Deferred income tax provision	(23,004)	(20,565)
Power and natural gas cost deferrals, net	74,643	(31,559)
Amortization of debt expense	1,039	1,980
Stock-based compensation expense	6,350	5,460
Equity-related AFUDC	(3,830)	(3,172)
Pension and other postretirement benefit expense	5,942	6,693
Other regulatory assets and liabilities	(14,028)	(31,997)
Other deferred debits and credits	22,469	32,351
Change in decoupling regulatory deferral	(18,752)	14,383
Realized and unrealized loss (gain) on assets and investments	(294)	2,752
Other	1,831	(2,436)
Contributions to defined benefit pension plan	(6,666)	(6,666)
Cash paid for settlement of interest rate swap agreements	—	(409)
Cash received for settlement of interest rate swap agreements	4,397	7,869
Changes in certain current assets and liabilities:		
Accounts and notes receivable	59,468	111,428
Inventory	(15,605)	(8,131)
Collateral for derivative instruments	18,453	116,602
Income taxes receivable	21,242	7,476
Other current assets	(81)	(20,228)
Accounts payable	(33,884)	(96,080)
Other current liabilities	(12,809)	(19,886)
Net cash provided by operating activities	316,995	269,561
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(251,207)	(226,746)
Issuance of notes receivable	—	(1,500)
Investments made in equity and property	(5,115)	(6,481)
Other	2,192	652
Net cash used in investing activities	(254,130)	(234,075)

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

For the Six Months Ended June 30
Dollars in thousands
(Unaudited)

	2024	2023
Financing Activities:		
Net decrease in short-term borrowings	$ (105,000)	$ (260,000)
Proceeds from issuance of long-term debt	83,700	250,000
Maturity of long-term debt and finance leases	(1,700)	(8,118)
Issuance of common stock, net of issuance costs	17,600	59,525
Cash dividends paid	(75,090)	(69,942)
Other	(2,731)	(4,675)
Net cash used in financing activities	(83,221)	(33,210)
Net increase (decrease) in cash and cash equivalents	(20,356)	2,276
Cash and cash equivalents at beginning of period	35,003	13,428
Cash and cash equivalents at end of period	$ 14,647	$ 15,704

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

Avista Corporation

For the Three and Six Months Ended June 30
Dollars in thousands
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Common Stock, Shares:				
Shares outstanding at beginning of period	78,187,093	75,762,598	78,074,587	74,945,948
Shares issued	515,024	761,586	627,530	1,578,236
Shares outstanding at end of period	78,702,117	76,524,184	78,702,117	76,524,184
Common Stock, Amount:				
Balance at beginning of period	$ 1,645,208	$ 1,555,651	$ 1,644,327	$ 1,525,185
Equity compensation expense	3,999	3,239	6,350	5,460
Issuance of common stock, net of issuance costs	17,485	29,613	17,600	59,525
Payment of minimum tax withholdings for share-based payment awards	—	—	(1,585)	(1,667)
Balance at end of period	1,666,692	1,588,503	1,666,692	1,588,503
Accumulated Other Comprehensive Loss:				
Balance at beginning of period	(366)	(2,076)	(357)	(2,058)
Other comprehensive loss	—	(19)	(9)	(37)
Balance at end of period	(366)	(2,095)	(366)	(2,095)
Retained Earnings:				
Balance at beginning of period	875,658	831,736	841,353	811,541
Net income	22,858	17,484	94,353	72,329
Dividends on common stock	(37,603)	(35,207)	(74,793)	(69,857)
Balance at end of period	860,913	814,013	860,913	814,013
Total equity	$ 2,527,239	$ 2,400,421	$ 2,527,239	$ 2,400,421
Dividends declared per common share	$ 0.475	$ 0.46	$ 0.95	$ 0.92

The Accompanying Notes are an Integral Part of These Statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

The accompanying condensed consolidated financial statements of Avista Corp. as of and for the interim periods ended June 30, 2024 and June 30, 2023 are unaudited; however, in the opinion of management, the statements reflect all adjustments necessary for a fair statement of the results for the interim periods. All such adjustments are of a normal recurring nature. The condensed consolidated financial statements have been prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. The Condensed Consolidated Statements of Income for the interim periods are not necessarily indicative of the results to be expected for the full year. These condensed consolidated financial statements do not contain the detail or footnote disclosure concerning accounting policies and other matters which would be included in full fiscal year consolidated financial statements; therefore, they should be read in conjunction with the Company's audited consolidated financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2023 (2023 Form 10-K).

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corp. is primarily an electric and natural gas utility with certain other business ventures. Avista Utilities is an operating division of Avista Corp., comprising its regulated utility operations in the Pacific Northwest. Avista Utilities provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Utilities also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Utilities has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Utilities also supplies electricity to a small number of customers in Montana.

AERC is a wholly-owned subsidiary of Avista Corp. The primary subsidiary of AERC is AEL&P, which comprises Avista Corp.'s regulated utility operations in Alaska.

Avista Capital, a wholly owned non-regulated subsidiary of Avista Corp., is the parent company of the subsidiary companies in the non-utility businesses, except AJT Mining Properties, Inc., which is a subsidiary of AERC. See Note 16 for business segment information.

Basis of Reporting

The condensed consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries and other majority owned subsidiaries and variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Intercompany balances were eliminated in consolidation. The accompanying condensed consolidated financial statements include the Company’s proportionate share of utility plant and related operations associated with its interests in jointly owned plants.

Regulation

The Company is subject to state regulation in Washington, Idaho, Montana, Oregon and Alaska. The Company is subject to federal regulation primarily by the FERC, as well as various other federal agencies with regulatory oversight of particular aspects of its operations.

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Condensed Consolidated Balance Sheets measured at estimated fair value.

The WUTC and the IPUC issued accounting orders authorizing Avista Corp. to offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. Realized benefits and costs result in adjustments to retail rates through PGAs, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rate cases. The resulting regulatory assets associated with energy commodity derivative instruments are probable of recovery through future rates.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as derivative assets or liabilities at estimated fair value with an offsetting regulatory asset or liability. Contracts not considered derivatives are accounted for on the accrual basis until they are settled or realized unless there is a decline in the fair value of the contract determined to be other-than-temporary.

For interest rate swap derivatives, Avista Corp. records all mark-to-market gains and losses in each accounting period as assets and liabilities, as well as offsetting regulatory assets and liabilities, such that there is no income statement impact. The interest rate swap derivatives are risk management tools similar to energy commodity derivatives. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt. The Company records an offset of interest rate swap derivative assets and liabilities with regulatory assets and liabilities, based on the prior practice of the commissions to provide recovery through the ratemaking process.

The Company has multiple master netting agreements with a variety of entities allowing for cross-commodity netting of derivative agreements with the same counterparty (i.e. power derivatives can be netted with natural gas derivatives). In addition, some master netting agreements allow for the netting of commodity derivatives and interest rate swap derivatives for the same counterparty. The Company does not have agreements which allow for cross-affiliate netting among multiple affiliated legal entities. The Company nets all derivative instruments when allowed by the agreement for presentation in the Condensed Consolidated Balance Sheets.

Fair Value Measurements

Fair value represents the price that would be received when selling an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Energy commodity derivative assets and liabilities, deferred compensation assets, some equity investments, as well as derivatives related to interest rate swaps and foreign currency exchange contracts, are reported at estimated fair value on the Condensed Consolidated Balance Sheets. See Note 11 for the Company’s fair value disclosures.

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses loss contingencies that do not meet these conditions for accrual if there is a reasonable possibility that a material loss may be incurred. See Note 15 for further discussion of the Company's commitments and contingencies.

NOTE 2. NEW ACCOUNTING STANDARDS

ASU 2022-03 "Fair Value Measurement of Equity Securities Subject to Contractual Sale Restrictions"

In June 2022, the FASB issued ASU 2022-03, Fair Value Measurement (Topic 820): Fair Value Measurement of Equity Securities Subject to Contractual Sale Restrictions. The purpose of this guidance is to clarify that a contractual restriction on the ability to sell an equity security is not considered part of the unit of account of the equity security, and therefore should not be considered when measuring the equity security's fair value. Additionally, an entity cannot separately recognize and measure a contractual sale restriction. This guidance also adds specific disclosures related to equity securities subject to contractual sale restrictions, including (i) the fair value of equity securities subject to contractual sale restrictions reflected in the balance sheet, (ii) the nature and remaining duration of the restrictions and (iii) the circumstances that could cause a lapse in the restrictions. The Company adopted the amendments effective January 1, 2024, with no material impacts to the Company's financial statements resulting upon adoption.

ASU 2023-06 "Disclosure Improvements - Codification Amendments in Response to the SEC's Disclosure Update and Simplification Initiative"

In October 2023, the FASB issued ASU 2023-06, which incorporates a variety of SEC required disclosures into the FASB Accounting Standards Codification (ASC). For entities subject to SEC's existing disclosure requirements, the effective date for each amendment will be the date on which the SEC removes the related disclosure from Regulation S-X or Regulation S-K, with early adoption permitted. If the SEC has not removed the applicable requirement from Regulation S-X or Regulation S-K by June 30, 2027, the disclosure requirements will be removed from the Codification. The requirements of the ASU will not have a material impact on the Company's financial statements.

ASU 2023-07 "Segment Reporting (Topic 280) - Improvements to Reportable Segment Disclosures"

In November 2023, the FASB issued ASU 2023-07, requiring additional disclosures around reportable segment information. The additional required disclosures include significant segment expenses, an amount for other segment activity not included in the disaggregated segment amounts and a description of the activity, and the title and position of the chief operating decision maker and an explanation of how they use the reported measures of segment profit or loss in assessing segment performance and allocating resources. The ASU is effective for fiscal years beginning after December 15, 2023 and interim periods beginning after December 15, 2024, and early adoption is permitted. The Company is in the process of evaluating the impact of the ASU; however, it has determined it will not early adopt.

ASU 2023-09 "Income Taxes (Topic 740) - Improvements to Income Tax Disclosures"

In December 2023, the FASB issued ASU 2023-09, requiring additional income tax disclosures. The additional disclosures include prescribed items presented in the income tax rate reconciliation, and further disaggregation of income taxes paid amounts between federal, state and foreign taxes. The ASU is effective for fiscal years beginning after December 15, 2024 and early adoption is permitted. The Company is in the process of evaluating the impact of the ASU; however, it has determined it will not early adopt.

NOTE 3. BALANCE SHEET COMPONENTS

Inventory

Inventories of materials and supplies, emission allowances, fuel stock and stored natural gas are recorded at average cost and consisted of the following as of June 30, 2024 and December 31, 2023 (dollars in thousands):

	June 30, 2024	December 31, 2023
Materials and supplies	$ 92,446	$ 81,651
Emission allowances	64,925	56,097
Stored natural gas	10,937	16,272
Fuel stock	7,280	5,964
Total	$ 175,588	$ 159,984

Other Current Assets

Other current assets consisted of the following as of June 30, 2024 and December 31, 2023 (dollars in thousands):

	June 30, 2024	December 31, 2023
Prepayments	$ 52,276	$ 52,752
Income taxes receivable	7,991	29,234
Derivative assets net of collateral	4,462	11,821
Other	11,988	9,977
Total	$ 76,717	$ 103,784

Net Utility Property

Net utility property, which is recorded at original cost, net of accumulated depreciation, consisted of the following as of June 30, 2024 and December 31, 2023 (dollars in thousands):

	June 30, 2024	December 31, 2023
Utility plant in service	$ 7,946,547	$ 7,799,481
Construction work in progress	222,560	179,527
Total	8,169,107	7,979,008
Less: Accumulated depreciation and amortization	2,341,964	2,278,952
Total	$ 5,827,143	$ 5,700,056

Other Property and Investments-Net and Other Non-Current Assets

Other property and investments-net and other non-current assets consisted of the following as of June 30, 2024 and December 31, 2023 (dollars in thousands):

	June 30, 2024	December 31, 2023
Equity investments	$ 157,369	$ 153,350
Operating lease ROU assets	66,864	67,585
Finance lease ROU assets	34,593	36,414
Non-utility property	33,508	33,813
Notes receivable	15,578	15,287
Long-term prepaid license fees	21,356	19,448
Pension asset	41,625	32,997
Investment in affiliated trust	11,547	11,547
Deferred compensation assets	8,551	7,794
Other	17,583	15,750
Total	$ 408,574	$ 393,985

Other Current Liabilities

Other current liabilities consisted of the following as of June 30, 2024 and December 31, 2023 (dollars in thousands):

	June 30, 2024	December 31, 2023
Accrued taxes other than income taxes	$ 28,572	$ 31,928
Derivative liabilities net of collateral	23,764	17,217
Employee paid time off accruals	35,110	32,072
Accrued interest	24,080	23,539
Climate Commitment Act obligations	—	19,081
Pensions and other postretirement benefits	11,130	14,082
Other	44,105	54,017
Total	$ 166,761	$ 191,936

Other Non-Current Liabilities and Deferred Credits

Other non-current liabilities and deferred credits consisted of the following as of June 30, 2024 and December 31, 2023 (dollars in thousands):

	June 30, 2024	December 31, 2023
Operating lease liabilities	$ 64,851	$ 63,559
Finance lease liabilities	37,313	39,095
Deferred investment tax credits	27,833	28,233
Climate Commitment Act obligations	65,046	26,026
Asset retirement obligations	18,210	18,058
Derivative liabilities net of collateral	8,665	17,902
Other	19,902	17,357
Total	$ 241,820	$ 210,230

Regulatory Assets and Liabilities

Regulatory assets and liabilities consisted of the following as of June 30, 2024 and December 31, 2023 (dollars in thousands):

	June 30, 2024		December 31, 2023	
	Current	Non-Current	Current	Non-Current
Regulatory Assets				
Energy commodity derivatives	$ 41,242	$ 10,362	$ 51,419	$ 17,720
Deferred Climate Commitment Act costs	39,558	20,530	—	46,022
Deferred power costs	17,859	12,895	29,190	20,654
Wildfire resiliency	10,487	12,490	—	23,737
Decoupling surcharge	8,133	8,218	4,638	5,469
Deferred natural gas costs	9,452	—	60,667	—
Deferred income taxes	—	247,393	—	244,303
Pension and other postretirement benefit plans	—	112,730	—	117,658
Interest rate swaps	—	175,820	—	179,489
AFUDC above FERC allowed rate	—	48,727	—	49,985
Settlement with Coeur d'Alene Tribe	—	36,134	—	36,692
Advanced meter infrastructure	—	27,827	—	29,345
Utility plant abandoned	—	36,878	—	38,274
Colstrip excess depreciation	—	22,347	—	19,429
COVID-19 deferrals	—	11,945	—	12,142
Demand side management programs	—	16,068	—	10,033
Other regulatory assets	3,658	44,403	413	43,216
Total regulatory assets	$ 130,389	$ 844,767	$ 146,327	$ 894,168
Regulatory Liabilities				
Other income tax related liabilities	$ 14,753	$ 54,559	$ 25,129	$ 56,582
Excess deferred income taxes	14,230	286,185	14,510	293,029
Deferred Climate Commitment Act revenues	34,670	9,435	—	37,231
Deferred power costs	250	2,463	—	4,000
Deferred natural gas costs	10,469	—	9,296	—
Decoupling rebate	9,648	2,869	18,680	6,344
Utility plant retirement costs	—	432,227	—	417,027
Interest rate swaps	—	24,405	—	23,752
COVID-19 deferrals	—	10,787	—	10,172
Other regulatory liabilities	10,365	6,131	8,392	8,529
Total regulatory liabilities	$ 94,385	$ 829,061	$ 76,007	$ 856,666

NOTE 4. REVENUE

The core principle of the revenue recognition model is that an entity should identify the various performance obligations in a contract, allocate the transaction price among the performance obligations and recognize revenue when (or as) the entity satisfies each performance obligation.

Utility Revenues

Revenue from Contracts with Customers

General

The majority of Avista Corp.'s revenue is from rate-regulated sales of electricity and natural gas to retail customers, which has two performance obligations, (1) having service available for a specified period (typically a month at a time) and (2) the delivery of energy to customers. The total energy price generally has a fixed component (basic charge) related to having service available and a usage-based component, related to the delivery and consumption of energy. The commodity is sold and/or delivered to and consumed by the customer simultaneously, and the provisions of the relevant utility commission authorization determine the charges the Company may bill the customer. Since all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized immediately.

Revenues from contracts with customers are presented in the Condensed Consolidated Statements of Income in the line item "Utility revenues, exclusive of alternative revenue programs."

Non-Derivative Wholesale Contracts

The Company has certain wholesale contracts that are not accounted for as derivatives and are considered revenue from contracts with customers. Revenue is recognized as energy is delivered to the customer or the service is available for a specified period of time, consistent with the discussion of rate-regulated sales above.

Alternative Revenue Programs (Decoupling)

ASC 606 retained existing GAAP associated with alternative revenue programs, which specified alternative revenue programs are contracts between an entity and a regulator of utilities, not a contract between an entity and a customer. GAAP requires the presentation of revenue arising from alternative revenue programs separately from revenues arising from contracts with customers on the Condensed Consolidated Statements of Income. The Company's decoupling mechanisms (also known as a FCA in Idaho) qualify as alternative revenue programs. Decoupling revenue deferrals are recognized in the Condensed Consolidated Statements of Income during the period they occur (i.e. during the period of revenue shortfall or excess due to fluctuations in customer usage), subject to certain limitations, and a regulatory asset or liability is established which will be surcharged or rebated to customers in future periods. GAAP requires that for an alternative revenue program, like decoupling, the revenue must be expected to be collected from customers within 24 months of the deferral to qualify for recognition in the Condensed Consolidated Statements of Income. Amounts included in the Company's decoupling program that are not expected to be collected from customers within 24 months are not recorded in the financial statements until the period in which revenue recognition criteria are met. The amounts expected to be collected from customers within 24 months represents an estimate made by the Company on an ongoing basis due to it being based on the volumes of electric and natural gas sold to customers on a go-forward basis.

The Company records alternative program revenues under the gross method, which is to amortize the decoupling regulatory asset/liability to the alternative revenue program line item on the Condensed Consolidated Statements of Income as it is collected from or refunded to customers. The cash passing between the Company and the customers is presented in revenue from contracts with customers since it is a portion of the overall tariff paid by customers. This method results in a gross-up to both revenue from contracts with customers and revenue from alternative revenue programs, but has a net zero impact on total revenue. Depending on whether the previous deferral balance being amortized was a regulatory asset or regulatory liability, and depending on the size and direction of the current year deferral of surcharges and/or rebates to customers, it could result in negative alternative revenue program revenue during the year.

Derivative Revenue

Most wholesale electric and natural gas transactions (including both physical and financial transactions), and the sale of fuel are considered derivatives, which are disclosed separately from revenue from contracts with customers. Revenue is recognized for these items upon the settlement/expiration of the derivative contract. Derivative revenue includes transactions entered into and settled within the same month.

Other Utility Revenue

Other utility revenue includes rent, sales of materials, late fees and other charges that do not represent contracts with customers. This revenue is excluded from revenue from contracts with customers, as this revenue does not represent items where a customer is a party that has contracted with the Company to obtain goods or services that are an output of the Company's ordinary activities in exchange for consideration. As such, these revenues are presented separately from revenue from contracts with customers.

Other Considerations for Utility Revenues

Gross Versus Net Presentation

Revenues and resource costs from Avista Utilities' settled energy contracts "booked out" (not physically delivered) are reported on a net basis as part of derivative revenues.

Utility-related taxes collected from customers (primarily state excise taxes and city utility taxes) are imposed on Avista Utilities as opposed to being imposed on customers; therefore, Avista Utilities is the taxpayer and records these transactions on a gross basis in revenue from contracts with customers and operating expense (taxes other than income taxes). The utility-related taxes collected from customers at AEL&P are imposed on the customers rather than AEL&P; therefore, the customers are the taxpayers and AEL&P is acting as their agent. As such, these transactions at AEL&P are presented on a net basis within revenue from contracts with customers.

Utility-related taxes included in revenue from contracts with customers were as follows for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2024	2023	2024	2023
Utility-related taxes	$ 17,086	$ 16,133	$ 43,667	$ 41,872

Significant Judgments and Unsatisfied Performance Obligations

The only significant judgments involving revenue recognition are estimates surrounding unbilled revenue and receivables from contracts with customers and estimates surrounding the amount of decoupling revenues that will be collected from customers within 24 months (discussed above).

The Company has certain capacity arrangements, where the Company has a contractual obligation to provide either electric or natural gas capacity to its customers for a fixed fee. Most of these arrangements are paid for in arrears by the customers and do not result in deferred revenue and only result in receivables from the customers. The Company has one capacity agreement where the customer makes payments throughout the year. As of June 30, 2024, the Company estimates it had unsatisfied capacity performance obligations of $4.5 million, which will be recognized as revenue in future periods as the capacity is provided to the customers. These performance obligations are not reflected in the financial statements, as the Company has not received payment for these services.

Disaggregation of Total Operating Revenue

The following table disaggregates total operating revenue by segment and source for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30, 2024	Three months ended June 30, 2023	Six months ended June 30, 2024	Six months ended June 30, 2023
Avista Utilities				
Revenue from contracts with customers	$ 319,373	$ 294,129	$ 818,755	$ 772,904
Derivative revenues	48,605	66,580	138,185	63,518
Alternative revenue programs	16,171	5,513	19,054	(13,525)
Other utility revenues	6,665	2,382	9,756	5,849
Total Avista Utilities	390,814	368,604	985,750	828,746
AEL&P				
Revenue from contracts with customers	11,035	11,023	25,337	25,234
Other utility revenues	183	171	339	323
Total AEL&P	11,218	11,194	25,676	25,557
Other non-utility revenues	40	139	62	265
Total operating revenues	$ 402,072	$ 379,937	$ 1,011,488	$ 854,568

Utility Revenue from Contracts with Customers by Type and Service

The following table disaggregates revenue from contracts with customers associated with the Company's electric operations for the three and six months ended June 30 (dollars in thousands):

	2024			2023		
	Avista Utilities	AEL&P	Total Utility	Avista Utilities	AEL&P	Total Utility
Three months ended June 30:						
ELECTRIC OPERATIONS						
Revenue from contracts with customers						
Residential	$ 92,809	$ 4,548	$ 97,357	$ 86,499	$ 4,418	$ 90,917
Commercial	85,344	6,424	91,768	81,346	6,544	87,890
Industrial	30,038	—	30,038	27,956	—	27,956
Public street and highway lighting	2,254	63	2,317	1,980	61	2,041
Total retail revenue	210,445	11,035	221,480	197,781	11,023	208,804
Transmission	9,538	—	9,538	8,475	—	8,475
Other revenue from contracts with customers	8,334	—	8,334	6,934	—	6,934
Total electric revenue from contracts with customers	$ 228,317	$ 11,035	$ 239,352	$ 213,190	$ 11,023	$ 224,213
Six months ended June 30:						
ELECTRIC OPERATIONS						
Revenue from contracts with customers						
Residential	$ 234,838	$ 11,702	$ 246,540	$ 209,322	$ 11,299	$ 220,621
Commercial	178,136	13,506	191,642	162,572	13,810	176,382
Industrial	58,104	—	58,104	53,123	—	53,123
Public street and highway lighting	4,418	129	4,547	3,935	125	4,060
Total retail revenue	475,496	25,337	500,833	428,952	25,234	454,186
Transmission	19,130	—	19,130	16,422	—	16,422
Other revenue from contracts with customers	24,395	—	24,395	24,227	—	24,227
Total electric revenue from contracts with customers	$ 519,021	$ 25,337	$ 544,358	$ 469,601	$ 25,234	$ 494,835

The following table disaggregates revenue from contracts with customers associated with the Company's natural gas operations for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2024	2023	2024	2023
	Avista Utilities	Avista Utilities	Avista Utilities	Avista Utilities
NATURAL GAS OPERATIONS				
Revenue from contracts with customers				
Residential	$ 54,427	$ 48,004	$ 187,397	$ 188,840
Commercial	29,293	25,477	97,292	97,802
Industrial and interruptible	3,195	4,128	7,160	9,656
Total retail revenue	86,915	77,609	291,849	296,298
Transportation	2,734	1,923	5,072	4,192
Other revenue from contracts with customers	1,407	1,407	2,813	2,813
Total natural gas revenue from contracts with customers	$ 91,056	$ 80,939	$ 299,734	$ 303,303

NOTE 5. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, swap derivatives and options, to manage the various risks relating to these commodity price exposures. Avista Corp. has an energy resources risk policy and control procedures to manage these risks.

As part of Avista Corp.'s resource procurement and management operations in the electric business, Avista Corp. engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Corp.'s load obligations and the use of these resources to capture available economic value through wholesale market transactions. These include sales and purchases of electric capacity and energy, fuel for electric generation, and derivative contracts related to capacity, energy and fuel. Such transactions are part of the process of matching resources with load obligations and hedging a portion of the related financial risks. These transactions range from terms of intra-hour up to multiple years.

As part of its resource procurement and management of its natural gas business, Avista Corp. makes continuing projections of its natural gas loads and assesses available natural gas resources including natural gas storage availability. Natural gas resource planning typically includes peak requirements, low and average monthly requirements and delivery constraints from natural gas supply locations to Avista Corp.'s distribution system. However, daily variations in natural gas demand can be significantly different than monthly demand projections. Based on these projections, Avista Corp. plans and executes a series of transactions to hedge a portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as three natural gas operating years (November through October) into the future. Avista Corp. also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets.

Avista Corp. plans for sufficient natural gas delivery capacity to serve its retail customers for a theoretical peak day event. Avista Corp. generally has more pipeline and storage capacity than what is needed during periods other than a peak-day. Avista Corp. optimizes its natural gas resources by using market opportunities to generate economic value that mitigates the fixed costs. Avista Corp. also optimizes its natural gas storage capacity by purchasing and storing natural gas when prices are traditionally lower, typically in the summer, and withdrawing during higher priced months, typically during the winter. However, if market conditions and prices indicate that Avista Corp. should buy or sell natural gas at other times during the year, Avista Corp. engages in optimization transactions to capture value in the marketplace. Natural gas optimization activities include, but are not limited to, wholesale market sales of surplus natural gas supplies, purchases and sales of natural gas to optimize use of pipeline and storage capacity, and participation in the transportation capacity release market.

The following table presents the underlying energy commodity derivative volumes as of June 30, 2024 expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
Remainder 2024	6	22	16,240	28,818	384	417	636	5,678
2025	—	—	20,613	24,585	317	175	1,115	1,125
2026	—	—	10,348	8,040	—	—	—	—
2027	—	—	2,475	900	—	—	—	—

As of June 30, 2024, there were no expected deliveries of energy commodity derivatives after 2027.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2023 expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2024	9	—	22,747	74,596	472	510	1,723	12,038
2025	—	—	12,505	19,590	11	96	1,115	1,125
2026	—	—	5,570	3,940	—	—	—	—

As of December 31, 2023, there were no expected deliveries of energy commodity derivatives after 2026.

(1) Physical transactions represent commodity transactions in which Avista Corp. will take or make delivery of either electricity or natural gas; financial transactions represent derivative instruments with delivery of cash in the amount of the benefit or cost but with no physical delivery of the commodity, such as futures, swap derivatives, options, or forward contracts.

The electric and natural gas derivative contracts above will be included in either power supply costs or natural gas supply costs during the period they are scheduled to be delivered and will be included in the various deferral and recovery mechanisms (ERM, PCA and PGAs), or in the general rate case process, and are expected to be recovered through retail rates from customers.

Foreign Currency Exchange Derivatives

A significant portion of Avista Corp.'s natural gas supply (including fuel for power generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of Avista Corp.'s short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices. The short-term natural gas transactions are settled within 60 days with U.S. dollars. Avista Corp. hedges a portion of the foreign currency risk by purchasing Canadian currency exchange derivatives when such commodity transactions are initiated. The foreign currency exchange derivatives and the unhedged foreign currency risk have not had a material effect on Avista Corp.'s financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations are included with natural gas supply costs for ratemaking.

The following table summarizes the foreign currency exchange derivatives outstanding as of June 30, 2024 and December 31, 2023 (dollars in thousands):

	June 30, 2024	December 31, 2023
Number of contracts	24	5
Notional amount (in United States dollars)	$ 1,905	$ 81
Notional amount (in Canadian dollars)	2,608	109

Interest Rate Swap Derivatives

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt, and future borrowing requirements. Avista Corp. may hedge a portion of its interest rate risk with financial derivative instruments, including interest rate swap derivatives. These interest rate swap derivatives are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

The following table summarizes the unsettled interest rate swap derivatives outstanding as of June 30, 2024 and December 31, 2023 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
June 30, 2024	1	$ 10,000	2025
December 31, 2023	2	$ 20,000	2024
	1	10,000	2025

See Note 9 for discussion of the remarketed bonds and the related settlement of interest rate swaps in connection with the pricing of the bonds in March 2024.

Summary of Outstanding Derivative Instruments

The amounts recorded on the Condensed Consolidated Balance Sheet as of June 30, 2024 and December 31, 2023 reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of June 30, 2024 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netted	Net Asset (Liability) on Balance Sheet
Interest rate swap derivatives				
Other property and investments-net and other non-current assets	483	—	—	483
Energy commodity derivatives				
Other current assets	5,444	(982)	—	4,462
Other property and investments-net and other non-current assets	265	—	—	265
Other current liabilities	10,372	(56,076)	21,940	(23,764)
Other non-current liabilities and deferred credits	1,575	(12,202)	1,962	(8,665)
Total derivative instruments recorded on the balance sheet	$ 18,139	$ (69,260)	$ 23,902	$ (27,219)

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of December 31, 2023 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netted	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Other current assets	$ 2	$ —	$ —	$ 2
Interest rate swap derivatives				
Other current assets	3,667	—	—	3,667
Other non-current liabilities and deferred credits	—	(182)	—	(182)
Energy commodity derivatives				
Other current assets	8,531	(379)	—	8,152
Other current liabilities	19,510	(79,082)	42,355	(17,217)
Other non-current liabilities and deferred credits	2,913	(20,633)	—	(17,720)
Total derivative instruments recorded on the balance sheet	$ 34,623	$ (100,276)	$ 42,355	$ (23,298)

Exposure to Demands for Collateral

Avista Corp.'s derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement. In the event of changes in market prices or a downgrade in Avista Corp.'s credit ratings or other established credit criteria, additional collateral may be required. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against Avista Corp.'s credit facilities and cash. Avista Corp. actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements.

The following table presents collateral outstanding related to its derivative instruments as of June 30, 2024 and December 31, 2023 (in thousands):

	June 30, 2024	December 31, 2023
Energy commodity derivatives		
Cash collateral posted	$ 23,902	$ 43,095
Letters of credit outstanding	6,900	20,000
Balance sheet offsetting	23,902	42,355

No letters of credit were outstanding, and no cash collateral was on deposit, related to interest rate swap derivatives as of June 30, 2024 and December 31, 2023.

Certain of Avista Corp.’s derivative instruments contain provisions that require Avista Corp. to maintain an "investment grade" credit rating from the major credit rating agencies. If Avista Corp.’s credit ratings were to fall below "investment grade," it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions.

The following table presents the aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position and the amount of additional collateral Avista Corp. could be required to post as of June 30, 2024 (in thousands):

	June 30, 2024
Energy commodity derivatives	
Liabilities with credit-risk-related contingent features	$ 22,440
Additional collateral to post	22,991

NOTE 6. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

Avista Utilities

The Company contributed $6.7 million in cash to the pension plan for the six months ended June 30, 2024, and expects to contribute $10.0 million in total for 2024.

The Company uses a December 31 measurement date for its defined benefit pension and other postretirement benefit plans. The following table sets forth the components of net periodic benefit costs for the three and six months ended June 30 (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2024	2023	2024	2023
Three months ended June 30:				
Service cost	$ 3,947	$ 3,100	$ 661	$ 532
Interest cost	8,217	8,521	1,726	1,909
Expected return on plan assets	(11,356)	(10,922)	(974)	(891)
Curtailment loss	169	—	—	—
Amortization of prior service cost (credit)	126	123	(263)	(263)
Net loss recognition	569	1,185	88	(8)
Net periodic benefit cost	$ 1,672	$ 2,007	$ 1,238	$ 1,279
Six months ended June 30:				
Service cost	$ 7,709	$ 7,994	$ 1,281	$ 1,350
Interest cost	16,582	15,753	3,472	2,953
Expected return on plan assets	(22,584)	(21,844)	(1,948)	(1,782)
Curtailment loss	169	—	—	—
Amortization of prior service cost (credit)	249	246	(526)	(526)
Net loss recognition	1,359	2,024	179	525
Net periodic benefit cost	$ 3,484	$ 4,173	$ 2,458	$ 2,520

Total service costs in the table above are recorded to the same accounts as labor expense. Labor and benefits expense is recorded to various projects based on whether the work is a capital project or an operating expense. Approximately 40 percent of all labor and benefits is capitalized to utility property and 60 percent is expensed to utility other operating expenses.

The non-service portion of costs in the table above are recorded to other expense below income from operations in the Condensed Consolidated Statements of Income or capitalized as a regulatory asset. Approximately 40 percent of the costs are capitalized to regulatory assets and 60 percent is expensed to the income statement.

In 2024, the Company offered pension participants an election to leave the pension plan for an alternative defined contribution 401(k) plan. In April 2024, it was determined that due to the number of participants electing to leave the pension plan, as well as the resulting decrease in expected future service, this event resulted in a curtailment of the pension plan, and an associated gain of $1.4 million for the reduction in the benefit obligation. This gain was offset against the unrecognized net actuarial loss (and recorded within a regulatory asset). There was also a $0.2 million loss recognized for the acceleration of unrecognized prior service costs. The curtailment triggered a remeasurement of pension plan. The impact of the remeasurement was not material to the Company's condensed consolidated financial statements.

NOTE 7. INCOME TAXES

In accordance with interim reporting requirements, the Company uses an estimated annual effective tax rate for computing its provisions for income taxes. An estimate of annual income tax expense (or benefit) is made each interim period using estimates for annual pre-tax income, income tax adjustments and tax credits. The estimated annual effective tax rates do not include discrete events such as tax law changes, examination settlements, accounting method changes or adjustments to tax expense or benefits attributable to prior years. Discrete events are recorded in the interim period in which they occur or become known. The estimated annual tax rate is applied to year-to-date pre-tax income to determine income tax expense (or benefit) for the interim period consistent with the annual estimate. In subsequent interim periods, income tax expense (or benefit) for the period is computed as the difference between the year-to-date amount reported for the previous interim period and the current period’s year-to-date amount.

The following table summarizes the significant factors impacting the difference between the Company's effective tax rate and the federal statutory rate for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,				Six months ended June 30,			
	2024		2023		2024		2023	
Federal income taxes at statutory rates	$ 4,904	21.0 %	$ 2,452	21.0 %	$ 20,402	21.0 %	$ 12,577	21.0 %
Increase (decrease) in tax resulting from:								
Flow through related to deduction of meters and mixed service costs (1)	(2,898)	(12.4)	(5,689)	(48.7)	(11,683)	(12.0)	(19,212)	(32.1)
Tax effect of regulatory treatment of utility plant differences	(1,463)	(6.3)	(1,525)	(13.1)	(5,974)	(6.1)	(5,212)	(8.7)
State income tax expense	179	0.8	232	2.0	718	0.7	798	1.3
Tax credits	(94)	(0.4)	(1,135)	(9.7)	(400)	(0.4)	(1,135)	(1.9)
Other	(133)	(0.6)	(145)	(1.3)	(262)	(0.3)	(254)	(0.4)
Total income tax expense (benefit)	$ 495	2.1 %	$ (5,810)	(49.8)%	$ 2,801	2.9 %	$ (12,438)	(20.8)%

(1) The Company's general rate cases included approval of base rate increases, offset by tax customer credits. As the tax customer credits are returned to customers, this results in a decrease to income tax expense as a result of flowing through the benefits related to meters and mixed service costs.

NOTE 8. SHORT-TERM BORROWINGS

Avista Corp.

Lines of Credit

Avista Corp. has a committed line of credit in the total amount of $500 million, with an expiration date of June 2028. The Company has the option to extend for two additional one year periods (subject to customary conditions). The committed line of credit is secured by non-transferable first mortgage bonds of Avista Corp. issued to the agent bank that are payable only to the extent that Avista Corp. defaults on its obligations under the committed line of credit.

Balances outstanding and interest rates on borrowings (excluding letters of credit) under Avista Corp.'s revolving committed line of credit were as follows as of June 30, 2024 and December 31, 2023 (dollars in thousands):

	June 30, 2024	December 31, 2023
Borrowings outstanding at end of period	$ 244,000	$ 349,000
Letters of credit outstanding at end of period	5,100	4,700
Average interest rate on borrowings at end of period	6.55 %	6.46 %

Letter of Credit Facility

Avista Corp. has a letter of credit agreement in the aggregate amount of $50 million. Either party may terminate the agreement at any time.

Avista Corp. had $6.5 million and $20.0 million in letters of credit outstanding under this agreement as of June 30, 2024 and December 31, 2023, respectively. Letters of credit are not reflected on the Condensed Consolidated Balance Sheets. If a letter of credit were drawn upon by the holder, Avista Corp. would have an immediate obligation to reimburse the bank that issued the letter of credit.

Covenants and Default Provisions

The short-term borrowing agreements contain customary covenants and default provisions, including a change in control (as defined in the agreements). The events of default under each of the credit facilities also include a cross default from other indebtedness (as defined) and, in the case of the letter of credit agreement, other obligations. The committed line of credit agreement also includes a covenant which does not permit the ratio of “consolidated total debt” to “consolidated total capitalization” of Avista Corp. to be greater than 65 percent at any time. As of June 30, 2024, the Company was in compliance with this covenant.

AEL&P

AEL&P has a committed line of credit in the amount of $25.0 million that expires in June 2028. There were no borrowings or letters of credit outstanding under this agreement as of June 30, 2024 and December 31, 2023. The committed line of credit is secured by non-transferable first mortgage bonds of AEL&P issued to the agent bank that would only become due and payable in the event, and then only to the extent, that AEL&P defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "consolidated total debt at AEL&P" to "consolidated total capitalization at AEL&P," including the impact of the Snettisham bonds to be greater than 67.5 percent at any time. As of June 30, 2024, AEL&P was in compliance with this covenant.

NOTE 9. LONG-TERM DEBT

In April 2024, the Company closed on the remarketing of $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds due in 2032 and 2034, respectively. The bonds are not subject to ordinary optional redemption. The bonds are secured by equal principal amounts of non-transferable first mortgage bonds of the Company. The interest rate on both series of bonds is 3.875 percent. Avista Corp. purchased the Forsyth bonds upon original issuance in December 2010, with the intention to hold the bonds until market conditions were favorable for remarketing the bonds to unaffiliated investors. While the Company was the holder of these bonds, the bonds were not reflected as an asset or a liability on the Consolidated Balance Sheets. Upon the remarketing of these bonds, the Company recognized long term debt of $83.7 million.

In connection with the pricing of the Forsyth bonds in March 2024, the Company cash-settled two interest rate swap derivatives (notional aggregate amount of $20.0 million) and received a net amount of $4.4 million, which will be amortized as a component of interest expense over the life of the bonds. See Note 5 for a discussion of interest rate swap derivatives.

The net proceeds from the remarketing of the Forsyth bonds were used to repay a portion of the borrowings outstanding under the Company's committed line of credit.

NOTE 10. LONG-TERM DEBT TO AFFILIATED TRUSTS

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities. The distribution rate on the Preferred Trust Securities is three-month CME Term SOFR plus 1.137 percent.

The distribution rates were as follows during the six months ended June 30, 2024 and the year ended December 31, 2023:

	June 30, 2024	December 31, 2023
Low distribution rate	6.48 %	5.64 %
High distribution rate	6.51 %	6.55 %
Distribution rate at the end of the period	6.48 %	6.51 %

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. The Preferred Trust Securities may be redeemed at the option of Avista Capital II at any time and mature on June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company owns 100 percent of Avista Capital II and has solely and unconditionally guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed. The Company does not include these capital trusts in its condensed consolidated financial statements as Avista Corp. is not the primary beneficiary. As such, the sole assets of the capital trusts are $51.5 million of junior subordinated deferrable interest debentures of Avista Corp., which are reflected on the Condensed Consolidated Balance Sheets. Interest expense to affiliated trusts in the Condensed Consolidated Statements of Income represents interest expense on these debentures.

NOTE 11. FAIR VALUE

The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable, and short-term borrowings as shown on the Condensed Consolidated Balance Sheets are reasonable estimates of their fair values. The carrying values of long-term debt (including current portion and material finance leases) and long-term debt to affiliated trusts as shown on the Condensed Consolidated Balance Sheets may be different from the estimated fair value. See below for the estimated fair value of long-term debt and long-term debt to affiliated trusts.

The fair value hierarchy prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to fair values derived from unobservable inputs (Level 3 measurements).

The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, but which are either directly or indirectly observable as of the reporting date. Level 2 includes financial instruments valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 – Pricing inputs include significant inputs generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management’s best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors including the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), and the impact of Avista Corp.’s nonperformance risk on its liabilities.

The following table sets forth the carrying value and estimated fair value of the Company's financial instruments not reported at estimated fair value on the Condensed Consolidated Balance Sheets as of June 30, 2024 and December 31, 2023 (dollars in thousands):

	June 30, 2024		December 31, 2023	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 1,100,000	$ 944,836	$ 1,100,000	$ 968,893
Long-term debt (Level 3)	1,533,700	1,181,680	1,450,000	1,166,512
Snettisham finance lease obligation (Level 3)	40,795	36,900	42,495	39,600
Long-term debt to affiliated trusts (Level 3)	51,547	46,284	51,547	46,098

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of market prices of 58.82 percent to 105.84 percent of the principal amount, where 100.0 percent of the principal amount (adjusted for unamortized discount or premium) represents the carrying value recorded on the Condensed Consolidated Balance Sheets. Level 2 long-term debt represents publicly issued bonds with quoted market prices; however, due to their limited trading activity, they are classified as Level 2 because brokers must generate quotes and make estimates if there is no trading activity near a period end. Level 3 long-term debt consists of private placement bonds and debt to affiliated trusts, which typically have no secondary trading activity. Fair values in Level 3 are estimated based on market prices from third party brokers using secondary market quotes for debt with similar risk and terms to generate quotes for Avista Corp. bonds. Due to the unique nature of the Snettisham finance lease obligation, the estimated fair value of these items was determined based on a discounted cash flow model using available market information. The Snettisham finance lease obligation fair value is determined using the Morgan Markets A Ex-Fin discount rate as published on June 30, 2024 and December 31, 2023.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Condensed Consolidated Balance Sheets as of June 30, 2024 and December 31, 2023 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
June 30, 2024					
Assets:					
Energy commodity derivatives	$ —	$ 17,656	$ —	$ (12,929)	$ 4,727
Interest rate swap derivatives	—	483	—	—	483
Equity Investments	—	—	50,357	—	50,357
Deferred compensation assets					
Mutual Funds:					
Fixed income securities (3)	995	—	—	—	995
Equity securities (3)	7,362	—	—	—	7,362
Total	$ 8,357	$ 18,139	$ 50,357	$ (12,929)	$ 63,924
Liabilities:					
Energy commodity derivatives (2)	$ —	$ 61,279	$ 7,981	$ (36,831)	$ 32,429
Total	$ —	$ 61,279	$ 7,981	$ (36,831)	$ 32,429
December 31, 2023					
Assets:					
Energy commodity derivatives (2)	$ —	$ 30,954	$ —	$ (22,802)	$ 8,152
Foreign currency exchange derivatives	—	2	—	—	2
Interest rate swap derivatives	—	3,667	—	—	3,667
Equity Investments	—	—	50,254	—	50,254
Deferred compensation assets					
Mutual Funds:					
Fixed income securities (3)	1,117	—	—	—	1,117
Equity securities (3)	6,524	—	—	—	6,524
Total	$ 7,641	$ 34,623	$ 50,254	$ (22,802)	$ 69,716
Liabilities:					
Energy commodity derivatives (2)	$ —	$ 91,844	$ 8,250	$ (65,157)	$ 34,937
Interest rate swap derivatives	—	182	—	—	182
Total	$ —	$ 92,026	$ 8,250	$ (65,157)	$ 35,119

(1) The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a legally enforceable master netting agreement exists. In addition, the Company nets derivative assets and derivative liabilities against any payables and receivables for cash collateral held or placed with these same counterparties.
(2) The Level 3 energy commodity derivative balances are associated with natural gas exchange agreements.
(3) Included in other property and investments-net and other non-current assets on the Condensed Consolidated Balance Sheets.

The difference between the amount of derivative assets and liabilities disclosed in respective levels in the table above and the amount of derivative assets and liabilities disclosed on the Condensed Consolidated Balance Sheets is due to netting arrangements with certain counterparties. See Note 5 for additional discussion of derivative netting.

To establish fair value for energy commodity derivatives, the Company uses quoted market prices and forward price curves to estimate the fair value of energy commodity derivative instruments included in Level 2. Electric derivative valuations are performed using market quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange pricing for similar instruments, adjusted for basin differences, using market quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

To establish fair values for interest rate swap derivatives, the Company uses forward market curves for interest rates for the term of the swaps and discounts the cash flows back to present value using an appropriate discount rate. The discount rate is calculated by third party brokers according to the terms of the swap derivatives and evaluated by the Company for reasonableness, with consideration given to the potential non-performance risk by the Company. Future cash flows of the interest rate swap derivatives are equal to the fixed interest rate in the swap compared to the floating market interest rate multiplied by the notional amount for each period.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets.

Level 3 Fair Value

Natural Gas Exchange Agreement

For the natural gas commodity exchange agreement, the Company uses the same Level 2 market quotes described above; however, the Company also estimates the purchase and sales volumes (within contractual limits) as well as the timing of those transactions. Changing the timing of volume estimates changes the timing of purchases and sales, impacting which brokered quote is used. Because the brokered quotes can vary significantly from period to period, the unobservable estimates of the timing and volume of transactions can have a significant impact on the calculated fair value. The Company currently estimates volumes and timing of transactions based on a most likely scenario using historical data. Historically, the timing and volume of transactions are not highly correlated with market prices and market volatility.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of June 30, 2024 (dollars in thousands):

	Fair Value (Net) at June 30, 2024	Valuation Technique	Unobservable Input	Range and Weighted Average Price
Natural gas exchange agreement	$ (7,981)	Internally derived weighted average cost of gas	Forward purchase prices	$1.86 - $2.34/mmBTU $2.05 Weighted Average
			Forward sales prices	$2.46 - $9.48/mmBTU $6.70 Weighted Average
			Purchase volumes	41,259 - 100,000 mmBTUs
			Sales volumes	75,000 - 310,000 mmBTUs

The valuation methods, significant inputs and resulting fair values described above were developed by the Company and are reviewed on at least a quarterly basis to ensure they provide a reasonable estimate of fair value each reporting period.

Equity Investments

The Company has two equity investments measured at fair value on a recurring basis. For one investment, fair value is determined using a market approach, starting with enterprise values from recent market transaction data for comparable companies with similar equity instruments. The market transaction data was used to estimate an enterprise value of the underlying investment and that value was allocated to the various classes of equity via an option pricing model and a waterfall approach. The selection of appropriate comparable companies and the expected time to a liquidation event requires management judgment. The significant assumptions in the analysis include the comparable market transactions and related enterprise values, time to liquidity event and the market discount for lack of liquidity. In the event there are relevant market transactions for the same or similar securities of the subject company or there is the reasonable possibility of a transaction occurring, those transactions are utilized as an input to the valuation with a probability weight applied to the valuation.

For the second investment, the fair value is determined using an income approach utilizing a discounted cash flow model. The model is based on income statement forecasts from the underlying company to determine cash flows for the period of ownership. The model then utilizes market multiples from publicly traded comparable companies in similar industries and projects to estimate the terminal fair value. The market multiples are reduced to reflect the difference in the life cycle between the publicly traded comparable companies and the start-up nature of the investment company. The selection of appropriate comparable companies, market multiples and the reduction to those market multiples requires management judgment. The significant assumptions in the model include the discount rate representing the risk associated with the investment, market multiples and the related reduction to those multiples, revenue forecasts, and the estimated terminal date for the investment. In the event there are relevant market transactions for the same or similar securities of the subject company or there is the reasonable possibility of a transaction occurring, those transactions are used to determine the fair value of Avista Corp.'s investment under a market approach instead of utilizing a discounted cash flow model. The market transactions are considered Level 3 inputs because they are not publicly available observable transactions.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 equity investments as of June 30, 2024 (dollars in thousands):

	Fair Value at June 30, 2024	Valuation Technique	Unobservable Input	Range
Equity investments	$ 50,357	Market approach	Comparable enterprise values	$130,000-$388,600 $246,000 Average
			Time to liquidity event	1.75 years
		Discounted cash flows	Revenue market multiples	0.36x to 5.90x Revenue 1.95x Average
			Market exit reduction	50%
			Discount rate	25%
			Annual revenues	$14,000 - $245,000
			Terminal date	2027

The following table presents activity for assets and liabilities measured at fair value using significant unobservable inputs (Level 3) for the three and six months ended June 30 (dollars in thousands):

	Natural Gas Exchange Agreement (1)	Equity Investments	Total
Three Months Ended June 30, 2024:			
Beginning balance	$ (7,403)	$ 51,829	$ 44,426
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities	(906)	—	(906)
Recognized in net income	—	(1,472)	(1,472)
Purchases and debt conversions	—	—	—
Settlements	328	—	328
Ending balance as of June 30, 2024	$ (7,981)	$ 50,357	$ 42,376
Three Months Ended June 30, 2023:			
Beginning balance	$ (11,062)	$ 51,014	$ 39,952
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities	(1,016)	—	(1,016)
Recognized in net income	—	(2,561)	(2,561)
Settlements	357	—	357
Ending balance as of June 30, 2023	$ (11,721)	$ 48,453	$ 36,732
Six Months Ended June 30, 2024:			
Beginning balance	$ (8,250)	$ 50,254	$ 42,004
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities	(18)	—	(18)
Recognized in net income	—	(842)	(842)
Purchases and debt conversions	—	945	945
Settlements	287	—	287
Ending balance as of June 30, 2024	$ (7,981)	$ 50,357	$ 42,376
Six Months Ended June 30, 2023:			
Beginning balance	$ (17,734)	$ 54,284	$ 36,550
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities	5,767	—	5,767
Recognized in net income	—	(5,198)	(5,198)
Purchases and debt conversions	—	2,367	2,367
Settlements	246	—	246
Other	—	(3,000)	(3,000)
Ending balance as of June 30, 2023	$ (11,721)	$ 48,453	$ 36,732

(1) There were no purchases, issuances or transfers from other categories during the periods presented in the table above.

NOTE 12. COMMON STOCK

The Company issued shares of common stock for total net proceeds of $17.5 million and $17.6 million during the three and six months ended June 30, 2024, respectively. Most of these shares were issued in at-the-market transactions pursuant to the Company's sales agency agreements under which the Company may offer and sell new shares of common stock through its sales agents from time to time. Under these sales agency agreements, the Company issued 0.5 million shares during the three and six months ended June 30, 2024.

NOTE 13. ACCUMULATED OTHER COMPREHENSIVE LOSS

Accumulated other comprehensive loss, net of tax, consisted of the following as of June 30, 2024 and December 31, 2023 (dollars in thousands):

	June 30, 2024	December 31, 2023
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $97 and $95, respectively	$ 366	$ 357

The following table details the reclassifications out of accumulated other comprehensive loss by component for the three and six months ended June 30 (dollars in thousands):

	Amounts Reclassified from Accumulated Other Comprehensive Loss			
	Three months ended June 30,		Six months ended June 30,	
Details about Accumulated Other Comprehensive Loss Components (Affected Line Item in Statement of Income)	2024	2023	2024	2023
Amortization of defined benefit pension and postretirement benefit items				
Amortization of net prior service cost (1)	$ (137)	$ (140)	$ (277)	$ (280)
Amortization of net loss (1)	657	1,177	1,538	2,549
Adjustment due to effects of regulation (1)	(520)	(1,061)	(1,272)	(2,316)
Total before tax (2)	—	(24)	(11)	(47)
Tax expense (2)	—	5	2	10
Net of tax (2)	$ —	$ (19)	$ (9)	$ (37)

(1) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 6 for additional details).

(2) Description is also the affected line item on the Condensed Consolidated Statements of Income.

NOTE 14. EARNINGS PER COMMON SHARE

The following table presents the computation of basic and diluted earnings per common share for the three and six months ended June 30 (in thousands, except per share amounts):

	Three months ended June 30,		Six months ended June 30,	
	2024	2023	2024	2023
Numerator:				
Net income	$ 22,858	$ 17,484	$ 94,353	$ 72,329
Denominator:				
Weighted-average number of common shares outstanding-basic	78,390	75,983	78,276	75,576
Effect of dilutive securities:				
Performance and restricted stock awards	66	148	57	127
Weighted-average number of common shares outstanding-diluted	78,456	76,131	78,333	75,703
Earnings per common share:				
Basic	$ 0.29	$ 0.23	$ 1.20	$ 0.96
Diluted	$ 0.29	$ 0.23	$ 1.20	$ 0.96

There were no shares excluded from the calculation because they were antidilutive.

NOTE 15. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For all such matters, the Company will vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any matter because litigation and other contested proceedings are subject to numerous uncertainties. For matters affecting Avista Utilities’ or AEL&P's operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

Collective Bargaining Agreements

The Company's collective bargaining agreement with the IBEW represents 36 percent of all Avista Utilities' employees. The Company's largest represented group, representing approximately 90 percent of Avista Utilities' bargaining unit employees in Washington and Idaho, are covered under a four year agreement which expires in March 2025.

The current agreement includes a clause to negotiate wages in effect for the last year of the agreement. On July 31, 2024, the IBEW voted to approve new wages for 2024 and 2025, with wages for 2024 effective retroactively to March 26, 2024 and wages for 2025 taking effect on January 1, 2025.

Boyds Fire (State of Washington Department of Natural Resources v. Avista)

In August 2019, the Company was served with a complaint, captioned “State of Washington Department of Natural Resources v. Avista Corporation,” seeking recovery of up to $4.4 million for fire suppression and investigation costs and related expenses incurred in connection with a wildfire that occurred in Ferry County, Washington, in August 2018. Specifically, the complaint alleges the fire, which became known as the “Boyds Fire,” was caused by a dead ponderosa pine tree falling into an overhead distribution line, and that Avista Corp., along with its independent vegetation management contractors Asplundh Tree Company and CN Utility Consulting, were negligent in failing to identify and remove the tree before it came into contact with the line. Avista Corp. disputes that it was negligent in failing to identify and remove the tree in question. Additional lawsuits were subsequently filed by private landowners seeking property damages, and holders of insurance subrogation claims seeking recovery of insurance proceeds paid.

The lawsuits were filed in the Superior Court of Ferry County, Washington, and is scheduled for trial on July 7, 2025. The Company continues to vigorously defend itself in the litigation. However, at this time the Company is unable to predict the likelihood of an adverse outcome or estimate a range of potential loss in the event of such an outcome.

Road 11 Fire

In April 2022, Avista Corp. received a notice of claim from property owners seeking damages of $5 million in connection with a fire that occurred in Douglas County, Washington, in July 2020. In June 2022, those claimants filed suit in the Superior Court of Douglas County, Washington, seeking unspecified damages. The fire, which was designated as the “Road 11 Fire,” occurred in the vicinity of an Avista Corp. 115kv line, resulting in damage to three overhead transmission structures. The fire occurred during a high wind event and grew to 10,000 acres before being contained. In June 2024, the parties reached an agreement to settle the matter for $0.1 million which will result in dismissal of the lawsuit with prejudice.

Labor Day 2020 Windstorm/ Babb Road Fire

In September 2020, a severe windstorm occurred in eastern Washington and northern Idaho. The extreme weather event resulted in customer outages and multiple wildfires in the region, including the Babb Road Fire, which occurred near the town of Malden, Washington. The Babb Road Fire covered approximately 15,000 acres and destroyed approximately 220 structures. There are no reports of personal injury or death resulting from the fire.

In May 2021 the Company learned the Washington Department of Natural Resources (DNR) had completed its investigation and issued a report on the Babb Road Fire.

The DNR report concluded, among other things, that

- the fire was ignited when a branch of a multi-dominant Ponderosa Pine tree was broken off by the wind and fell on an Avista Corp. distribution line;
- the tree was located approximately 30 feet from the center of Avista Corp.’s distribution line and approximately 20 feet beyond Avista Corp.’s right-of-way;

- the tree showed some evidence of insect damage, a small area of scarring where a lateral branch/leader (LBL) had broken off in the past, and some past signs of Gall Rust disease.

The DNR report concluded that: “because of the unusual configuration of the tree, and its proximity to the powerline, a closer inspection was warranted. A nearer inspection of the tree should have revealed the cut LBL ends and its previous failure, and necessitated determination of the failure potential of the adjacent LBL, implicated in starting the Babb Road Fire.”

The DNR report acknowledged that, other than the multi-dominant nature of the tree, the conditions mentioned above would not have been easily visible without close-up inspection of, or cutting into, the tree. The report also acknowledged that, while the presence of multiple tops would have been visible from the nearby roadway, the tree did not fail at a v-fork due to the presence of multiple tops. The Company contends that applicable inspection standards did not require a closer inspection of the otherwise healthy tree, nor was the Company negligent with respect to its maintenance, inspection or vegetation management practices.

Eleven lawsuits have been filed in connection with the Babb Road fire. Asplundh Tree Company and CN Utility Consulting, which both perform vegetation management services as independent contractors to the Company, are also named as defendants in each of the lawsuits. The lawsuits include six subrogation actions filed by 51 insurance companies seeking to recover approximately $23 million purportedly paid to insureds to date; and five actions on behalf of 128 individual plaintiffs seeking unspecified damages, one of which was originally filed as a class action lawsuit on behalf of three putative individual plaintiffs but which has since been amended to assert direct claims on behalf of the named plaintiffs. In the course of discovery, 29 individual plaintiffs have provided economic damage estimates, claiming total economic losses of approximately $5.1 million, of which approximately $2.4 million is covered by insurance or other forms of reimbursement. These plaintiffs may also seek as-yet unspecified non-economic damages (pain and suffering and emotional distress). The Company does not believe non-economic damages are applicable in this case and plans to dispute such claims.

All proceedings, except for one action filed on September 1, 2023 on behalf of three individual plaintiffs (the "Widman Action") have been consolidated in the Superior Court of Spokane County Washington under the lead action Blakeley v. Avista Corporation et al., and variously assert causes of action for negligence, private nuisance, and trespass (the "Blakeley Proceeding").

In November 2023, all parties to the Blakeley Proceeding agreed to a stipulated order, which was presented to and entered by the Superior Court of Spokane County, Washington. The order consolidates the Blakeley Proceeding for trial (in addition to discovery and pre-trial proceedings) and bifurcates the trial into liability and damages phases, such that the initial trial in the case will focus solely on whether the defendants are legally responsible for the Babb Road Fire. A trial date on the liability phase has been set for May 5, 2025. The Widman Action is set for trial on October 6, 2025.

In addition, the stipulated order relating to the Blakeley Proceeding memorializes the plaintiffs' agreement to voluntarily dismiss all claims asserting inverse condemnation as a theory of liability, without prejudice to their ability to seek permission from the Court to refile those claims at a later date if they can show good cause to do so. The Widman Action does not include claims for inverse condemnation. The parties to the Blakeley Proceeding agreed to a preliminary mediation no later than 60 days prior to the liability trial, and, if there is a trial following that mediation and if the jury returns a verdict in the plaintiffs' favor in the liability trial, a second mediation within 90 days following the verdict focusing on damages. Finally, the plaintiffs agreed to complete a damages questionnaire identifying all claimed damages being sought in connection with the litigation.

In June 2024, a motion was filed in one of the individual actions (the "VanDyke Action") to add three additional plaintiffs. Although the statute of limitations for new claims has passed, the plaintiffs intend to argue that the addition of new plaintiffs is timely because the lawsuit was initially pled as a class action. Alternatively, the three new plaintiffs will ask the Court to be added as plaintiffs in the case with a claim for inverse condemnation, which carries a longer statute of limitations. The Company intends to contest the addition of any new plaintiffs to the action.

The Company will vigorously defend itself in the legal proceedings; however, at this time the Company is unable to predict the likelihood of an adverse outcome or estimate a range of potential loss in the event of such an outcome.

Orofino Fire

In August 2023, a fire subsequently referred to as the "Hospital Fire" started in windy conditions near Orofino, Idaho, burning 53 acres and seven primary residences, as well as several outbuildings. The Idaho Department of Lands investigated and has issued a report in which it concluded the fire was caused by an electrical fault igniting three separate spots which then spread uphill. The Company has a distribution line in the area near the ignition point. The Company has to date found no evidence suggesting negligence on its part. Except for two claims for damage to personal property, the Company has not, at this time, received any claims in connection with the fire. The Company will vigorously defend itself in the event any such claims are asserted; however, at this time, it is unable to estimate the likelihood of an adverse outcome nor the amount or range of a potential loss in the event of an adverse outcome.

Colstrip

Colstrip Owners Arbitration and Litigation

Colstrip Units 3 and 4 are owned by the Company, PacifiCorp, Portland General Electric (PGE), and Puget Sound Energy (PSE) (collectively, the "Western Co-Owners"), as well as NorthWestern and Talen Montana, LLC (Talen), as tenants in common under an Ownership and Operating Agreement, dated May 6, 1981, as amended (O&O Agreement), in the percentages set forth below:

Co-Owner	Unit 3	Unit 4
Avista	15 %	15 %
PacifiCorp	10 %	10 %
PGE	20 %	20 %
PSE	25 %	25 %
NorthWestern	—	30 %
Talen	30 %	—

Colstrip Units 1 and 2, owned by PSE and Talen, were shut down in 2020 and are in the process of being decommissioned. The co-owners of Units 3 and 4 also own undivided interests in facilities common to both Units 3 and 4, as well as in certain facilities common to all four Colstrip units.

The Washington Clean Energy Transformation Act (CETA), among other things, imposes deadlines by which each electric utility must eliminate from its electricity rates in Washington the costs and benefits associated with coal-fired resources, such as Colstrip. The practical impact of CETA is electricity from such resources, including Colstrip, may no longer be delivered to Washington retail customers after 2025.

The co-owners of Colstrip Units 3 and 4 have differing needs for the generating capacity of these units. Accordingly, certain business disagreements have arisen among the co-owners, including, disagreements as to the requirements for shutting down these units. NorthWestern has initiated arbitration pursuant to the O&O Agreement to resolve these business disagreements, and two actions have been initiated to compel arbitration of those disputes: one by Talen in the Montana Thirteenth Judicial District Court for Yellowstone County, and one by the Western Co-Owners, which is pending in Montana Federal District Court. In light of the ownership transfer agreements, the Colstrip owners agreed to stay both the litigation and the arbitration through March 2024. On April 1, 2024, the agreement to stay lapsed and the parties are now in the process of reengaging in arbitration discussions. An arbitration date has not yet been scheduled. The Company cannot predict the ultimate outcome of the arbitration process.

Agreement Between Avista and NorthWestern

In January 2023, the Company entered into an agreement with NorthWestern under which, subject to the terms and conditions specified in the agreement, the Company will transfer its 15 percent ownership in Colstrip Units 3 and 4 to NorthWestern. There is no monetary exchange included in the transaction. The transaction is scheduled to close on December 31, 2025 or such other date as the parties mutually agree upon.

Under the agreement, the Company will remain obligated through the close of the transaction to pay its share of (i) operating expenses, (ii) capital expenditures, but not in excess of the portion allocable pro rata to the portion of useful life (through 2030) expired through the close of the transaction, and (iii) site remediation expenses except certain costs relating to post closing activities.

In addition, the Company would enter into an agreement under which it would retain its voting rights with respect to decisions relating to remediation.

The Company will retain its Colstrip transmission system assets, which are excluded from the transaction.

Under the Colstrip O&O Agreement, each of the other owners of Colstrip has a 90-day period in which to evaluate the transaction and determine whether to exercise their respective rights of first refusal as to a portion of the generation being turned over to NorthWestern. That period has now expired, and no owners have exercised a right to first refusal.

The transaction is subject to the satisfaction of customary closing conditions including the receipt of any required regulatory approvals, as well as NorthWestern's ability to enter into a new coal supply agreement by December 31, 2024.

The Company does not expect this transaction to have a direct material impact on its financial results.

Agreement Between PSE and NorthWestern

In July 2024, PSE entered into an agreement with NorthWestern under which, PSE will transfer its 25 percent ownership in Colstrip Units 3 and 4 to NorthWestern. There is no monetary exchange included in the transaction. The transaction is scheduled to close on December 31, 2025.

Burnett et al. v. Talen et al.

Multiple property owners initiated a legal proceeding (titled *Burnett et al. v. Talen et al.*) in the Montana District Court for Rosebud County against Talen, PSE, PacifiCorp, PGE, Avista Corp., NorthWestern, and Westmoreland Rosebud Mining. The plaintiffs allege a failure to contain coal dust in connection with the operation of Colstrip, and seek unspecified damages. The Colstrip Owners reached a settlement with one of the litigants, Richard Burnett, for an amount of less than $0.1 million. The settlement does not involve or implicate the claims of any other litigants. The Company will vigorously defend itself in the litigation, but at this time is unable to predict the outcome, nor an amount or range of potential impact in the event of an outcome adverse to the Company’s interests.

Westmoreland Mine Permits

Two lawsuits have been commenced by the Montana Environmental Information Center and others, challenging certain permits relating to the operation of the Westmoreland Rosebud Mine, which provides coal to Colstrip. In the first, the Montana District Court for Rosebud County issued an order vacating a permit for one area of the mine, which decision was subsequently upheld by the Montana Supreme Court. In the second, the Montana Federal District Court vacated a decision by the federal Office of Surface Mining Reclamation and Enforcement, a branch of the United States Department of the Interior, approving expansion of the mine into a new area, pending further analysis of potential environmental impact. An initial appeal of that decision to the Ninth Circuit was dismissed for lack of jurisdiction, pending further proceedings before the Department of the Interior. Avista Corp. is not a party to either of these proceedings, but continues to monitor the progress of both issues and assess the impact, if any, of the proceedings on Westmoreland’s ability to meet its contractual coal supply obligations.

National Park Service (NPS) - Natural and Cultural Damage Claim

In March 2017, the Company accessed property managed by the National Park Service (NPS) to prevent the imminent failure of a power pole surrounded by flood water in the Spokane River. The Company voluntarily reported its actions to the NPS several days later. Thereafter, in March 2018, the NPS notified the Company that it might seek recovery for unspecified costs and damages allegedly caused during the incident pursuant to the System Unit Resource Protection Act (SURPA), 54 U.S.C. 100721 et seq. In January 2021, the United States Department of Justice (DOJ) requested the Company and the DOJ renew discussions relating to the matter. In July 2021, the DOJ communicated that it may seek damages of approximately $2 million in connection with the incident for alleged damage to “natural and cultural resources”. In addition, the DOJ indicated that it may seek treble damages under the SURPA and state law, bringing its total potential claim to approximately $6 million.

In April 2024 the parties reached a settlement in principle, through which the Company has agreed to pay $0.9 million in order to settle all claims and allegations relating to the matter. The settlement in principle is contingent upon execution of a mutually acceptable settlement agreement, as well as a required public notice and comment period to be initiated by NPS and/or the DOJ.

Rathdrum, Idaho Natural Gas Incident

In October 2021, there was an incident in Rathdrum, Idaho involving the Company’s natural gas infrastructure. The incident occurred after a third party damaged those facilities during excavation work. The incident resulted in a fire which destroyed one residence and resulted in minor injuries to the occupants. In January 2023, the Company was served with a lawsuit filed in the District Court of Kootenai County, Idaho by one property owner, seeking unspecified damages. In February 2024, the Company became aware of a second lawsuit filed by the owners of the adjacent property, seeking damages for personal injury and emotional distress from having witnessed the incident. The Company will vigorously defend itself in the legal proceedings; however, at this time the Company is unable to predict the likelihood of an adverse outcome or estimate a range of potential loss in the event of such an outcome.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes any ultimate liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows. It is possible a change could occur in the Company’s estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant. See "Note 22 of the Notes to Consolidated Financial Statements" in the 2023 Form 10-K for additional discussion regarding other contingencies.

NOTE 16. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. The Company's management evaluates performance based on income (loss) from operations before income taxes as well as net income (loss). The accounting policies of the segments are the same as those described in the summary of significant accounting policies. Avista Utilities' business is managed based on the total regulated utility operation; therefore, it is considered one segment. AEL&P is a separate reportable business segment, as it has separate financial reports reviewed in detail by the Chief Operating Decision Maker and its operations and risks are sufficiently different from Avista Utilities and the other businesses at AERC that it cannot be aggregated with other operating segments. The Other category, which is not a reportable segment, includes other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital.

The following table presents information for each of the Company's business segments (dollars in thousands):

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the three months ended June 30, 2024:						
Operating revenues	$ 390,814	$ 11,218	$ 402,032	$ 40	$ —	$ 402,072
Resource costs	143,125	1,201	144,326	—	—	144,326
Other operating expenses	105,532	4,059	109,591	358	—	109,949
Depreciation and amortization	64,973	2,856	67,829	2	—	67,831
Income (loss) from operations	51,752	2,824	54,576	(320)	—	54,256
Interest expense (2)	35,035	1,415	36,450	642	(512)	36,580
Income tax expense (benefit)	714	374	1,088	(593)	—	495
Net income (loss)	23,935	1,109	25,044	(2,186)	—	22,858
Capital expenditures (3)	127,916	4,582	132,498	—	—	132,498
For the three months ended June 30, 2023:						
Operating revenues	$ 368,604	$ 11,194	$ 379,798	$ 139	$ —	$ 379,937
Resource costs	140,017	1,227	141,244	—	—	141,244
Other operating expenses	99,276	3,795	103,071	749	—	103,820
Depreciation and amortization	63,419	2,729	66,148	—	—	66,148
Income (loss) from operations	41,257	3,161	44,418	(610)	—	43,808
Interest expense (2)	34,044	1,452	35,496	448	(318)	35,626
Income tax expense (benefit)	(5,556)	473	(5,083)	(727)	—	(5,810)
Net income (loss)	18,810	1,359	20,169	(2,685)	—	17,484
Capital expenditures (3)	121,834	4,422	126,256	—	—	126,256
For the six months ended June 30, 2024:						
Operating revenues	$ 985,750	$ 25,676	$ 1,011,426	$ 62	$ —	$ 1,011,488
Resource costs	435,633	1,810	437,443	—	—	437,443
Other operating expenses	212,847	7,993	220,840	674	—	221,514
Depreciation and amortization	130,058	5,698	135,756	5	—	135,761
Income (loss) from operations	146,389	9,600	155,989	(617)	—	155,372
Interest expense (2)	71,066	2,815	73,881	1,212	(952)	74,141
Income tax expense (benefit)	1,514	1,861	3,375	(574)	—	2,801
Net income (loss)	91,443	5,020	96,463	(2,110)	—	94,353
Capital expenditures (3)	245,160	6,047	251,207	—	—	251,207
For the six months ended June 30, 2023:						
Operating revenues	$ 828,746	$ 25,557	$ 854,303	$ 265	$ —	$ 854,568
Resource costs	332,154	2,018	334,172	—	—	334,172
Other operating expenses	200,665	7,384	208,049	1,760	—	209,809
Depreciation and amortization	125,883	5,453	131,336	31	—	131,367
Income (loss) from operations	111,816	10,119	121,935	(1,526)	—	120,409
Interest expense (2)	68,118	2,904	71,022	795	(536)	71,281
Income tax expense (benefit)	(13,504)	2,012	(11,492)	(946)	—	(12,438)
Net income (loss)	70,437	5,401	75,838	(3,509)	—	72,329
Capital expenditures (3)	219,598	7,148	226,746	3	—	226,749
Total Assets:						
As of June 30, 2024:	$ 7,240,803	$ 273,961	$ 7,514,764	$ 194,145	$ (25,139)	$ 7,683,770
As of December 31, 2023:	$ 7,262,704	$ 269,683	$ 7,532,387	$ 191,665	$ (21,575)	$ 7,702,477

(1) Intersegment eliminations reported as interest expense represent intercompany interest.
(2) Including interest expense to affiliated trusts.
(3) The capital expenditures for the other businesses are included in other investing activities on the Condensed Consolidated Statements of Cash Flows.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of
Avista Corporation

Results of Review of Interim Financial Information

We have reviewed the accompanying condensed consolidated balance sheet of Avista Corporation and subsidiaries (the "Company") as of June 30, 2024, the related condensed consolidated statements of income, comprehensive income, and equity for the three-month and six-month periods ended June 30, 2024 and 2023, and of cash flows for the six-month periods ended June 30, 2024 and 2023 and the related notes (collectively referred to as the "interim financial information"). Based on our reviews, we are not aware of any material modifications that should be made to the accompanying interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheet of the Company as of December 31, 2023, and the related consolidated statements of income, comprehensive income, equity, and cash flows for the year then ended (not presented herein); and in our report dated February 20, 2024, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2023, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

Basis for Review Results

This interim financial information is the responsibility of the Company's management. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our reviews in accordance with standards of the PCAOB. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the PCAOB, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

/s/ Deloitte & Touche LLP

Portland, Oregon

August 6, 2024

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

Management’s Discussion and Analysis of Financial Condition and Results of Operations was prepared in accordance with the SEC’s Regulation S-K for interim financial information and with the instructions to Form 10-Q. This Management’s Discussion and Analysis of Financial Condition and Results of Operations does not contain the full detail or analysis, or the full discussion of trends and uncertainties, that would accompany financial statements for a full fiscal year; therefore, it should be read in conjunction with the Company's 2023 Form 10-K.

Business Segments

Our business segments have not changed during the six months ended June 30, 2024. See the 2023 Form 10-K as well as “Note 16 of the Notes to Condensed Consolidated Financial Statements” for further information regarding our business segments.

The following table presents net income (loss) for each of our business segments (and the other businesses) for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2024	2023	2024	2023
Avista Utilities	$ 23,935	$ 18,810	$ 91,443	$ 70,437
AEL&P	1,109	1,359	5,020	5,401
Other	(2,186)	(2,685)	(2,110)	(3,509)
Net income	$ 22,858	$ 17,484	$ 94,353	$ 72,329

Executive Overview

Overall Results

Net income for the three and six months ended June 30, 2024 increased compared to the three and six months ended June 30, 2023, primarily due to the effects of general rate cases and the quarterly distribution of fewer tax customer credits to annual income taxes in 2024, as compared to 2023. These increases in earnings were partially offset by increased operating expenses and depreciation and amortization expense.

More detailed explanations of the fluctuations in revenues and expenses are provided in the results of operations and business segment discussions (Avista Utilities, AEL&P, and the other businesses) that follow this summary.

Severe Weather; Resource Adequacy

Extreme weather events, both in summer and winter, are becoming more frequent and more severe. These events have resulted in system load peaks that were higher than anticipated and, at certain times, higher than the capacity available at the time from resources owned by us or under firm contract. These unplanned capacity deficits are exacerbated by weather and other factors that reduce the availability of generating facilities, particularly hydroelectric and other renewable resources. Historically, we have been able to meet peak demand with short-term purchases of energy in the wholesale market. However, these weather events have highlighted the growing need for additional generating capacity both on our system and in the Pacific Northwest region. Accordingly, we are taking the increased peaks in demand into account as we consider our resource adequacy and generation requirements. In addition, the transition to clean energy (including the replacement of emitting facilities with non-emitting facilities, which are impacted by conditions outside of our control), electrification and other increasing needs for electric energy also factor into the analysis of the need for additional generation. As a result, we expect additional generating capacity will be needed earlier than reflected in our 2023 integrated resource plan. We are in the process of evaluating potential acceleration of our generation additions as compared to our most recent integrated resource plan filed in June 2023. A draft preferred resource plan will be submitted to the WUTC and IPUC in September 2024, and the final integrated resource plan will be filed in January 2025.

2024 Hydroelectric Generation and Snowpack Conditions

During the first half of 2024, our region experienced low precipitation, resulting in low snowpack levels and streamflows when compared to historical averages. This had a negative impact on our hydroelectric generation resources during the first half of the year and will continue to negatively impact hydroelectric generation for the remainder of the year. Expected lower hydroelectric generation increased net power supply costs and resulted in us absorbing additional costs under the ERM in Washington. In the six months ended June 30, 2024, we had a $4.7 million pre-tax expense under the ERM in Washington. We expect to absorb additional costs under the ERM in the second half of 2024.

Washington Climate Commitment Act (CCA)

Effective January 1, 2023, the CCA went into effect in the State of Washington, requiring us to secure carbon allowances to cover our carbon emissions over a certain amount each year. Costs associated with the CCA are being deferred and are included in Washington natural gas customer rates starting in April 2024. The resulting aggregate increase to customer bills was approximately 3.7 percent, and impacts customers differently based on revenue class, income level, and meter connection date. See "Environmental Issues and Contingencies" within our Form 10-K for 2023 for further discussion of the CCA and expected impacts on our financial results.

Regulatory Lag

Regulatory "lag" is inherent in utility ratemaking; a result of the delay between the investment in utility plant and/or the increase in costs and the receipt of an order of a public utility commission authorizing an increase in rates sufficient to recover such investment or costs. Regulatory lag can be mitigated to some extent by the incorporation of reasonably expected forward-looking information into an authorization of increased rates. However, there is no protection against unexpected inflation and increased interest rates, as experienced in 2022 and 2023. While we believe our recent general rate settlements are helpful, some increases in our costs will have to be addressed in future rate cases, including our 2024 Washington general rate cases. See "Regulatory Matters" for additional discussion of the general rate cases.

Regulatory Matters

General Rate Cases

We regularly review the need for electric and natural gas rate changes in each state in which we provide service. We expect to continue to file for rate adjustments to:

- seek recovery of operating costs and capital investments, and
- seek the opportunity to earn reasonable returns as allowed by regulators.

With regard to the timing and plans for future filings, the assessment of our need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include, but are not limited to, in-service dates of major capital investments and the timing of changes in major revenue and expense items.

Avista Utilities

Washington General Rate Cases

2024 General Rate Cases

On January 18, 2024, we filed multi-year electric and natural gas general rate cases with the WUTC. If approved, new rates would be effective in December 2024 and December 2025.

The proposed rates are designed to increase annual base electric revenues by $77.1 million, or 13.0 percent, effective in December 2024, and $53.7 million, or 11.7 percent, effective in December 2025.

For natural gas, the proposed rates are designed to increase annual base natural gas revenues by $17.3 million, or 13.6 percent, effective in December 2024, and $4.6 million, or 3.2 percent, effective in December 2025.

The proposed electric and natural gas revenue increase requests are based on a 10.4 percent return on equity with a common equity ratio of 48.5 percent and a rate of return on rate base of 7.61 percent. Increasing power supply costs, operating and maintenance costs, and ongoing capital investments (including clean energy hydroelectric projects, continued investment in the wildfire resiliency plan, replacement of natural gas distribution pipe and technology upgrades) were the main drivers of proposed increases.

In the second year of the proposed electric multi-year rate plan, in compliance with Washington's CETA, we have removed from customers' rates the costs associated with Colstrip.

As a part of the electric rate case, we proposed certain updates to power supply costs. The updated power supply costs included as a part of the first rate year, accounts for $18.5 million of our overall electric request. For electric rate year 2, the net effect of increasing base power supply costs (primarily to make up for the loss of Colstrip from our generation portfolio), offset by reductions in customer rates through the removal of Colstrip rate base and expenses, accounts for $35.1 million of our overall $53.7 million request.

Additionally, we are proposing changes to the ERM. Under the present construct, the ERM consists of a $4 million deadband, and then an asymmetric sharing band between $4 million and $10 million. All costs above $10 million are shared on a 90 percent customer, 10 percent company basis. As part of this rate case, we are proposing moving the entire mechanism to a 95 percent customer, 5 percent company sharing of power supply cost above or below the authorized level.

The cases are continuing through the normal regulatory process, which involves several rounds of testimony and an evidentiary hearing. These subsequent filings could potentially reflect changes in our originally-requested revenues, due to updates to power supply costs for more current market pricing, among other items. The WUTC has up to eleven months to review the general rate case filings and issue a decision, which is expected in December 2024.

Idaho General Rate Cases

2023 General Rate Cases

In February 2023, we filed multi-year electric and natural gas general rate cases with the IPUC. In August 2023, the IPUC approved the multi-party settlement agreement designed to increase annual base electric revenues by $22.1 million, or 8.0 percent, effective in September 2023, and $4.3 million, or 1.4 percent, effective in September 2024. The agreement was designed to increase annual base natural gas revenues by $1.3 million, or 2.7 percent, effective in September 2023, and a negligible increase effective in September 2024.

The settlement was based on an ROE of 9.4 percent, with a common equity ratio of 50 percent, and an ROR of 7.19 percent.

2025 General Rate Cases

We expect to file electric and natural gas general rate cases with the IPUC in the first quarter of 2025.

Oregon General Rate Case

2023 General Rate Case

In March 2023, we filed a natural gas general rate case with the OPUC. In October 2023, the OPUC approved the all party settlement agreement filed in August 2023. The approved rates are designed to increase annual base natural gas revenues by $7.2 million, or 9.4 percent effective January 1, 2024. The OPUC approved an ROR of 7.24 percent, a common equity ratio of 50 percent, and an ROE of 9.5 percent.

2024 General Rate Case

We expect to file a natural gas general rate case with the OPUC in the fourth quarter of 2024.

AEL&P

Alaska General Rate Case

In August 2023, the RCA issued a final order related to AEL&P’s electric general rate case, which was originally filed in July 2022.

The order reflects an 11.45 percent ROE, a common equity ratio of 60.7 percent, and an ROR of 8.79 percent. The order also results in an approved base electric revenue increase of 6.0 percent (designed to increase annual electric revenues by $2.1 million), and also makes non-refundable the interim rate increase of 4.5 percent that was approved by the RCA in August 2022 and took effect in September 2022. The final increase to rates was effective in October 2023.

Avista Utilities

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to customers with little to no change in utility margin (operating revenues less resource costs) or net income. In Washington and Idaho, all costs under the PGAs are passed through to customers. In Oregon, we absorb (cost or benefit) 10 percent of the difference between actual and projected natural gas costs included in retail rates for supply to the extent not hedged. Total net deferred natural gas costs among all jurisdictions were liabilities of $1.0 million as of June 30, 2024 and assets of $51.4 million as of December 31, 2023.

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used in Washington to track certain differences between actual power supply costs, net of the margin on wholesale sales of energy and sales of fuel, and the amount included in base retail rates for our customers. See the 2023 Form 10-K for a full discussion of the mechanics of the ERM and the various customer/Company sharing bands. Total net deferred power costs under the ERM were assets of $30.3 million and $37.6 million as of June 30, 2024 and December 31, 2023, respectively. These deferred power cost balances represent amounts due from customers. Pursuant to WUTC requirements, should the cumulative deferral balance exceed $30 million in either the rebate or surcharge direction, we must make a filing with the WUTC to adjust customer rates to return the balance to customers or recover the balance from customers, as the case may be. As of June 30, 2024, $17.4 million of the $30.3 million is still being recovered through a rate surcharge to customers over a two-year period, effective July 1, 2023, as approved by the WUTC.

The PCA mechanism in Idaho allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference (positive or negative) between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. The October 1 rate adjustments recover or rebate power supply costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a liability of $2.7 million and an asset of $7.6 million as of June 30, 2024 and December 31, 2023, respectively.

Decoupling Mechanisms

Decoupling (also known as an FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of our jurisdictions, electric and natural gas revenues from residential and certain commercial customers are adjusted so as to be based on the number of customers and assumed "normal" kilowatt hour and therm sales, rather than being based on actual kilowatt hour and therm sales. The difference between revenues based on the number of customers and "normal" sales and revenues based on actual usage is deferred and either surcharged or rebated to customers beginning in the following year. See the 2023 Form 10-K for a discussion of the mechanisms in each jurisdiction.

Total net cumulative decoupling deferrals among all jurisdictions were regulatory assets of $3.8 million as of June 30, 2024 and regulatory liabilities of $14.9 million as of December 31, 2023. Decoupling regulatory assets represent amounts due from customers. Decoupling regulatory liabilities represent amounts due to customers.

See "Results of Operations - Avista Utilities" for further discussion of the amounts recorded to operating revenues in 2024 and 2023 related to the decoupling mechanisms.

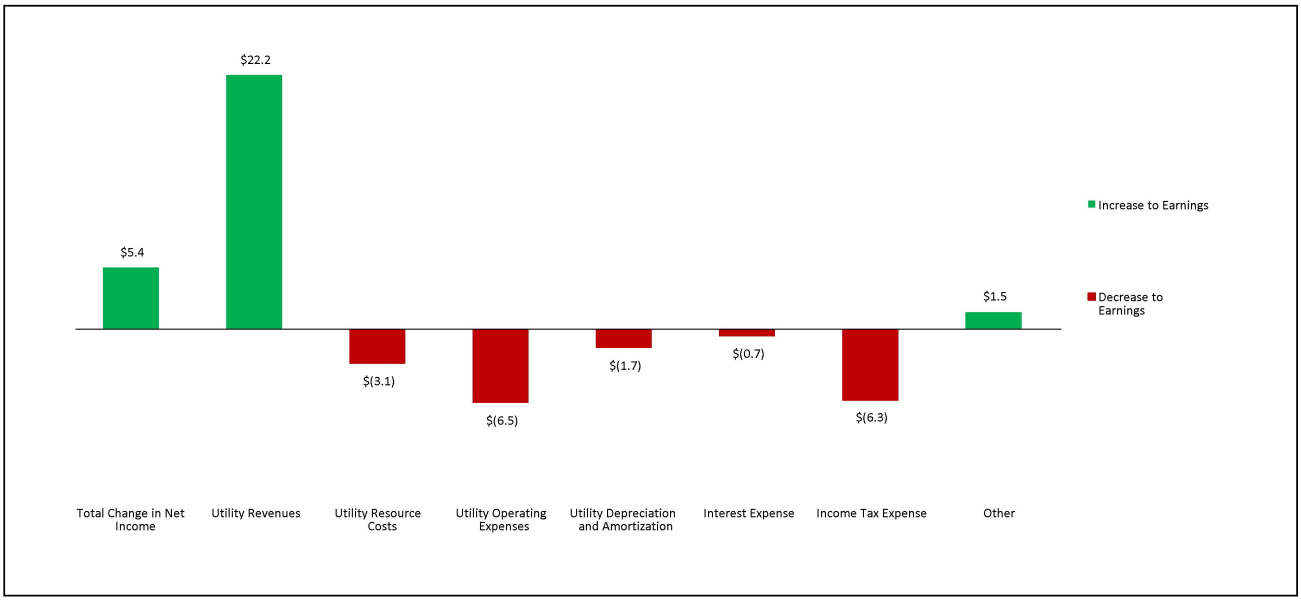
Results of Operations - Overall

The following provides an overview of changes in our Condensed Consolidated Statements of Income. More detailed explanations are provided, particularly for operating revenues and operating expenses, in the business segment discussions (Avista Utilities, AEL&P, and the other businesses) that follow this section.

The balances included below for utility operations reconcile to the Condensed Consolidated Statements of Income.

Three months ended June 30, 2024 compared to the three months ended June 30, 2023

The following graph shows the total change in net income for the second quarter of 2024 compared to the second quarter of 2023, as well as the various factors that caused such change (dollars in millions):



Electric utility revenues increased as a result of the effects of general rate cases, and the ERM surcharge to customers partially offset by decreased wholesale sales as part of our resource optimization activities. Natural gas utility revenues increased primarily due to increased retail revenues.

Utility resource costs increased primarily due to increased natural gas and electric costs deferred in prior periods that are being amortized in 2024. These were partially offset by a decrease in natural gas deferrals in the current period and a decrease in fuel for generation.

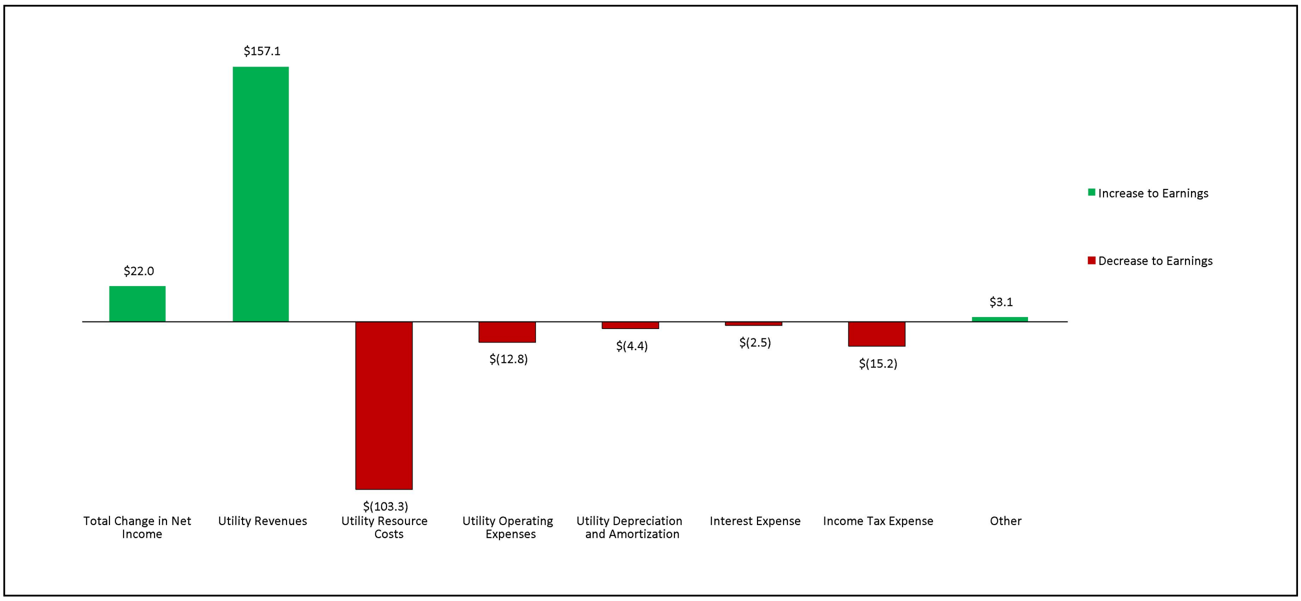
Utility operating expenses increased due to increased thermal generation costs, vegetation management, legal and employee medical expenses, as well as increased amortizations of previously deferred wildfire mitigation costs now included in customer rates (resulting in no impact to net income).

Utility depreciation and amortization increased primarily due to additions to utility plant.

Income tax was an expense in the second quarter of 2024, compared to a benefit in the second quarter of 2023. The change is primarily due to the decrease in tax customer credits which offset a portion of the bill impact of rate increases included in our prior general rate cases. This decrease in tax customer credits was partially offset by the timing impact of spreading these fewer available credits over the year as a percentage of pre-tax income based on the estimated annual effective tax rate. See "Note 7 of the Notes to Condensed Consolidated Financial Statements" for further details and a reconciliation of our effective tax rate.

Six months ended June 30, 2024 compared to the six months ended June 30, 2023

The following graph shows the total change in net income for the six months ended June 30, 2024 compared to the six months ended June 30, 2023, as well as the various factors that caused such change (dollars in millions):



Electric utility revenues increased as a result of the effects of general rate cases, the ERM surcharge to customers, and increased wholesale sales and sales of fuel as part of our resource optimization activities. Natural gas utility revenues increased primarily due to increased wholesale revenues.

Electric utility resource costs increased primarily due to increased purchased power and fuel for generation, as well as increased power supply costs deferred in prior periods that are being amortized in 2024. Natural gas utility resource costs increased due to an increase in net amortizations of previously deferred costs. The increased net amortizations was partially offset by decreased purchased natural gas costs.

Utility operating expenses increased due to increased thermal generation costs, vegetation management, legal and employee medical expenses, as well as increased amortizations of previously deferred wildfire mitigation costs now included in customer rates (resulting in no impact to net income).

Utility depreciation and amortization increased primarily due to additions to utility plant.

Income tax was an expense in the first half of 2024, compared to a benefit in the first half of 2023. The change is primarily due to the decrease in tax customer credits offsetting the bill impact of rate increases included in our prior general rate cases. This decrease in tax customer credits was partially offset by the timing impact of spreading these fewer available credits over the year as a percentage of pre-tax income based on the estimated annual effective tax rate. See "Note 7 of the Notes to Condensed Consolidated Financial Statements" for further details and a reconciliation of our effective tax rate.

Non-GAAP Financial Measures

The following discussion for Avista Utilities includes two financial measures considered “non-GAAP financial measures”: electric utility margin and natural gas utility margin.

Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts included (excluded) in the most directly comparable measure calculated and presented in accordance with GAAP. Electric utility margin is electric operating revenues less electric resource costs, while natural gas utility margin is natural gas operating revenues less natural gas resource costs. The most directly comparable GAAP financial measure to electric and natural gas utility margin is utility operating revenues as presented in "Note 16 of the Notes to Condensed Consolidated Financial Statements."

The presentation of electric utility margin and natural gas utility margin is intended to enhance the understanding of operating performance. We use these measures internally and believe they provide useful information to investors in their analysis of how changes in loads (due to weather, economic or other conditions), rates, supply costs and other factors impact our results of operations. Changes in loads, as well as power and natural gas supply costs, are generally deferred and recovered from customers through regulatory accounting mechanisms. Accordingly, the analysis of utility margin generally excludes most of the change in revenue resulting from these regulatory mechanisms. We present electric and natural gas utility margin separately below for Avista Utilities since each business has different cost sources, cost recovery mechanisms and jurisdictions, so we believe separate analysis is beneficial. These measures are not intended to replace utility operating revenues as determined in accordance with GAAP as an indicator of operating performance. Reconciliations of operating revenues to utility margin are set forth below.

Results of Operations - Avista Utilities
Resource Optimization

We engage in resource optimization, which involves the selection from available energy resources to serve our load obligations and the use of these resources to capture economic value through wholesale market transactions, which is ultimately intended to lower net power and natural gas supply costs. Our resource optimization transactions can take the form of physical sales and purchases of energy (natural gas or electricity), electric capacity and fuel for electric generation, as well as financial derivative contracts related to capacity, energy, fuel and fuel transportation. See our 2023 Form 10-K for further discussion of our optimization activities.

We typically enter into multiple transactions simultaneously to capture value. Even though these transactions are considered together when determining the net impact, they are recorded in separate items within components of utility operating revenue and resource costs and can cause fluctuations in each item. Gains and losses on financial derivative contracts are included in certain line items below (such as wholesale sales and purchases of power and natural gas, sales of fuel, and other fuel costs). The ERM, PCA and PGAs are based on net supply costs and consider all transactions related to resource procurement and optimization (both physical and financial).

Three months ended June 30, 2024 compared to the three months ended June 30, 2023

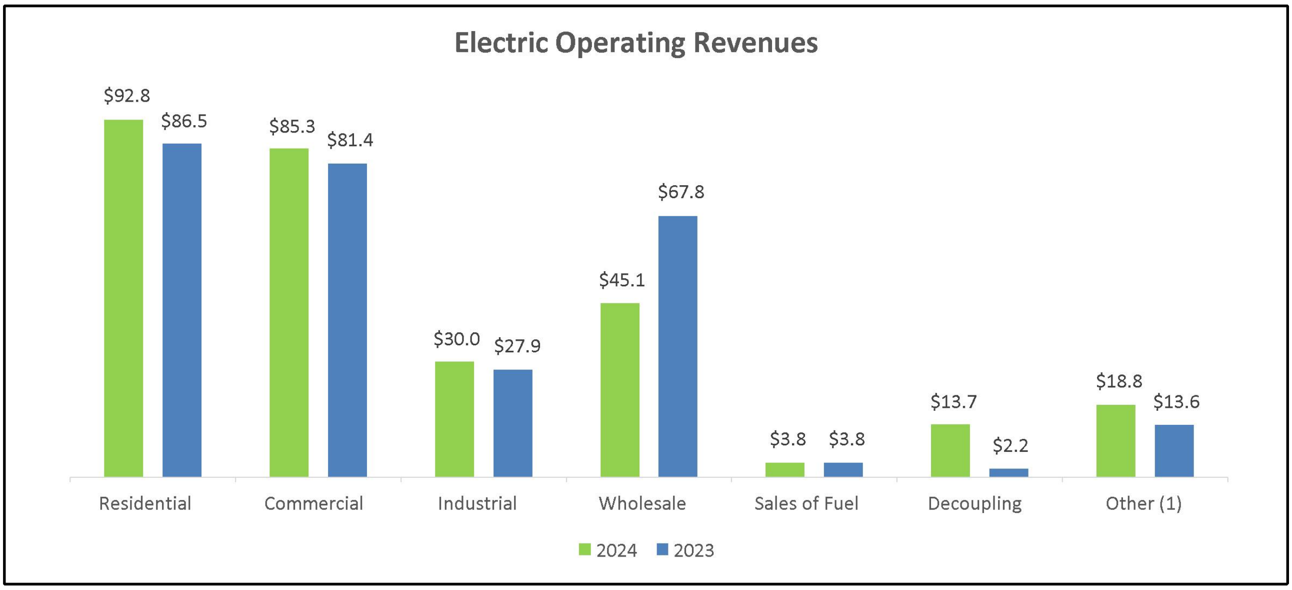
Utility Operating Revenues

Customers

The following table presents Avista Utilities' average number of electric and natural gas retail customers for the three months ended June 30, 2024 and 2023:

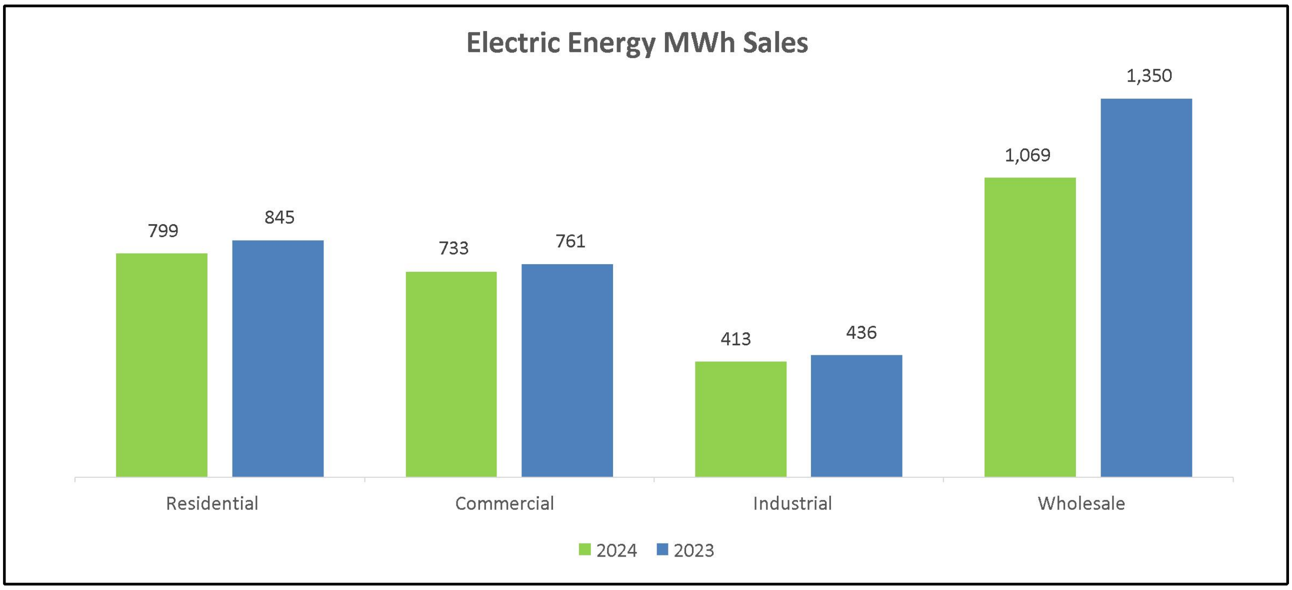
	Electric Customers		Natural Gas Customers	
	2024	2023	2024	2023
Residential	369,978	365,537	342,691	340,506
Commercial	45,703	45,438	37,306	37,129
Interruptible	—	—	51	50
Industrial	1,177	1,193	184	186
Public street and highway lighting	763	689	—	—
Total retail customers	417,621	412,857	380,232	377,871

The following graphs present Avista Utilities' electric operating revenues and megawatt-hour (MWh) sales for the three months ended June 30, 2024 and 2023 (dollars in millions and MWhs in thousands):



(1) This balance includes public street and highway lighting, which is considered part of retail electric revenues.

Total electric operating revenues in the graph above include intracompany sales of $1.2 million and $2.1 million for the three months ended June 30, 2024 and 2023, respectively.



The following table presents the current year decoupling deferrals and the amortization of prior year decoupling deferrals reflected in utility electric operating revenues for the three months ended June 30 (dollars in thousands):

	Electric Decoupling Revenues	
	2024	2023
Current year decoupling deferrals (a)	$ 8,336	$ 476
Amortization of prior year decoupling deferrals (b)	5,438	1,755
Total electric decoupling revenue	$ 13,774	$ 2,231

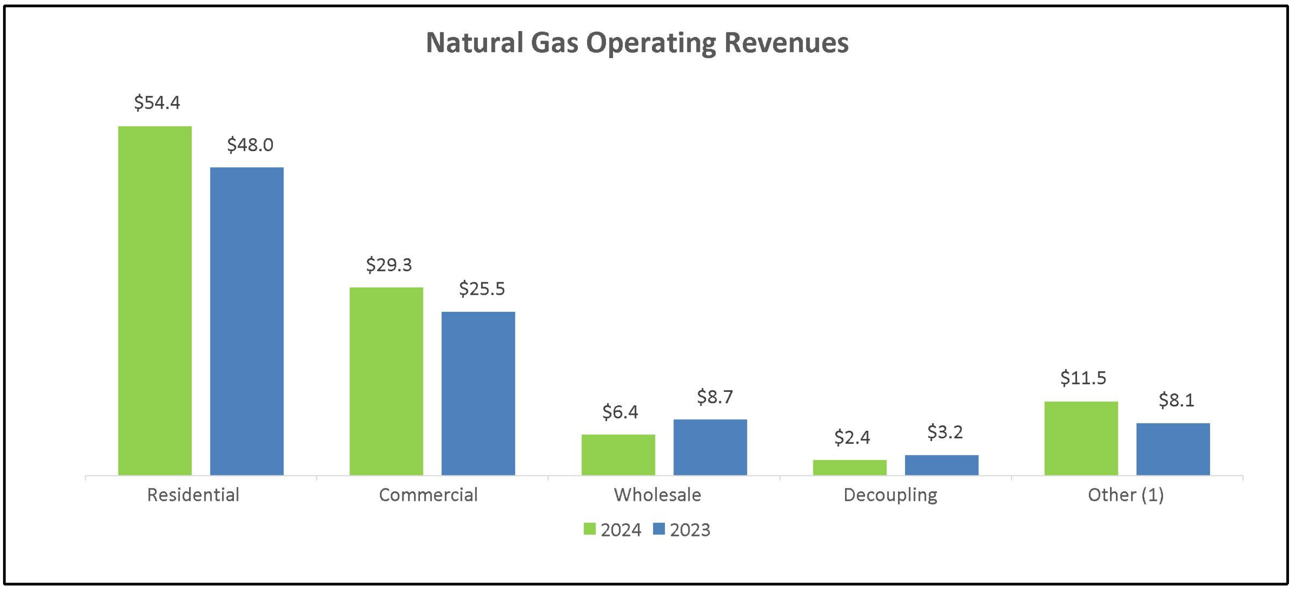
(a) Positive amounts are increases in decoupling revenue in the current year due to lower customer usage and will be surcharged to customers in future years. Negative amounts are decreases in decoupling revenue in the current year due to higher customer usage and will be rebated to customers in future years.

(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years due to higher customer usage and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative amounts are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years due to lower customer usage and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

Total electric revenues increased $6.3 million for the second quarter of 2024 as compared to the second quarter of 2023. The primary changes that occurred during the period were as follows:

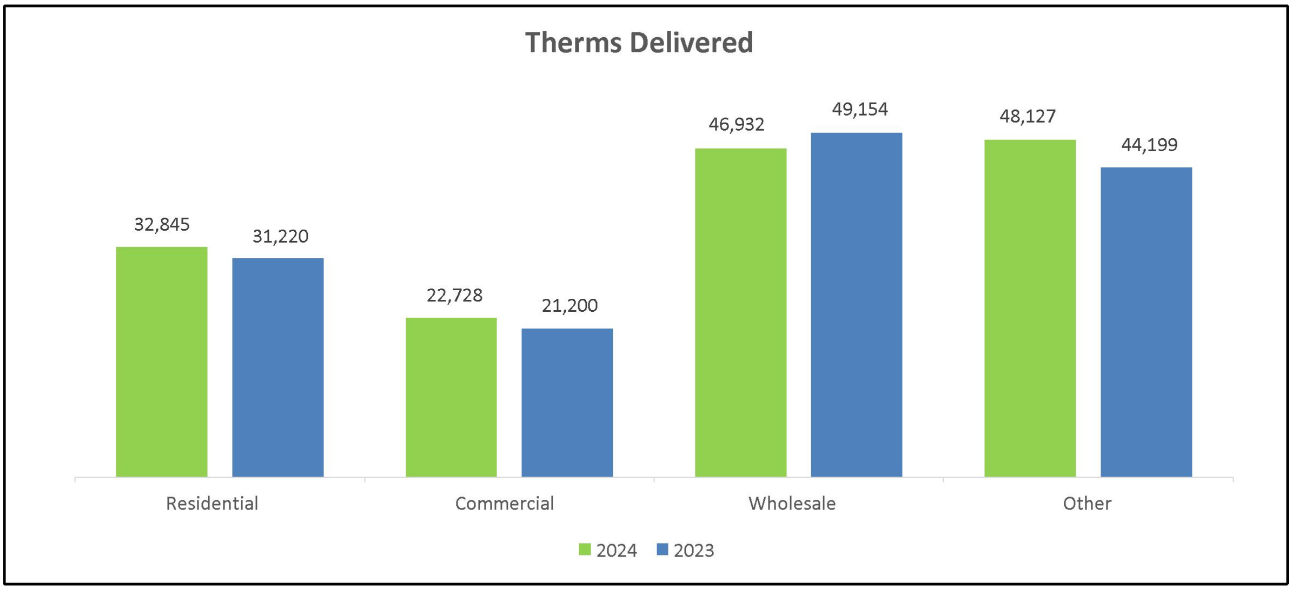
- A $12.7 million increase in retail electric revenue due to an increase in retail rates (increased revenues by $23.1 million), partially offset by a decrease in MWhs sold (decreased revenues by $10.4 million).
  - Retail rates increased mainly due to the effects of our general rate cases. The ERM surcharge to customers that commenced in July 2023 also increased retail rates.
  - Retail sales volumes decreased primarily due to decreased use by our residential and commercial customers. Compared to the second quarter of 2023, residential use per customer decreased 7 percent and commercial use per customer decreased 4 percent primarily due to milder weather and decreased cooling loads. The decrease in use per customer was partially offset by customer growth.
- A $22.7 million decrease in wholesale electric revenues due to a decrease in sales volumes (decreased revenues $11.9 million), and a decrease in sales prices (decreased revenues $10.8 million). The change in volumes was due to fewer opportunities to optimize our generation assets based on market conditions.
- An $11.5 million increase in electric decoupling revenue, resulting mostly from increased current year deferrals (due to lower use per customer), as well as increased amortization of prior year rebate balances.
- A $5.2 million increase in other electric revenues primarily from increased REC revenue, as well as increased transmission revenue.

The following graphs present Avista Utilities' natural gas operating revenues and therms delivered for the three months ended June 30, 2024 and 2023 (dollars in millions and therms in thousands):



(1) This balance includes interruptible and industrial revenues, which are considered part of retail natural gas revenues.

Total natural gas operating revenues in the graph above include intracompany sales of $1.4 million and $6.0 million for the three months ended June 30, 2024 and 2023, respectively.



The following table presents the current year decoupling deferrals and the amortization of prior year decoupling deferrals reflected in utility natural gas operating revenues for the three months ended June 30 (dollars in thousands):

	Natural Gas Decoupling Revenues	
	2024	2023
Current year decoupling deferrals (a)	$ 2,726	$ 4,661
Amortization of prior year decoupling deferrals (b)	(329)	(1,380)
Total natural gas decoupling revenue	$ 2,397	$ 3,281

(a) Positive amounts are increases in decoupling revenue in the current year due to lower customer usage and will be surcharged to customers in future years. Negative amounts are decreases in decoupling revenue in the current year due to higher customer usage and will be rebated to customers in future years.

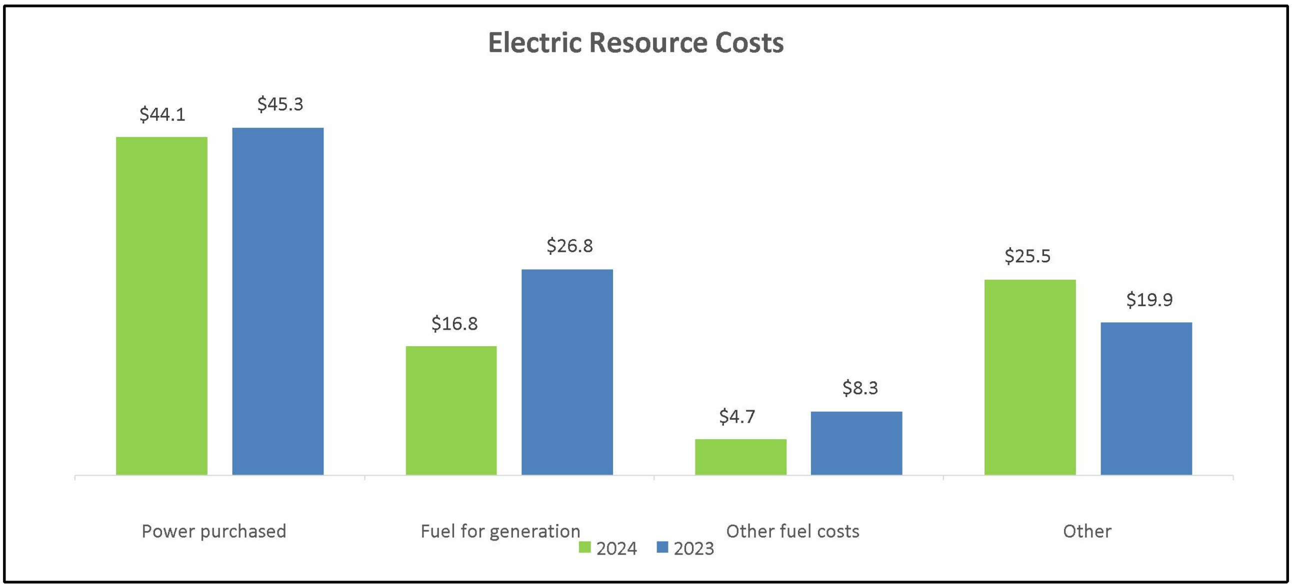
(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years due to higher customer usage and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative amounts are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years due to lower customer usage and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

Total natural gas revenues increased $10.5 million for the second quarter of 2024 as compared to the second quarter of 2023. The primary changes that occurred during the period were as follows:

- A $9.3 million increase in natural gas retail revenues (including industrial, which is included in other) due to increased sales volumes (increased revenues $4.3 million), and higher retail rates (increased revenues $5.0 million). The increase in sales volumes was primarily due to increased residential and commercial usage, resulting from slightly higher heating degree days in the beginning of the second quarter. Compared to the second quarter of 2023, residential use per customer increased 4 percent, and commercial firm use per customer increased 7 percent primarily due to colder weather. Retail rates increased mainly due to the effects of our general rate cases and rate increases associated with the CCA.
- A $2.3 million decrease in wholesale natural gas revenues, due to decreased optimization opportunities.
- A $0.8 million decrease in natural gas decoupling revenue primarily due to current year surcharges to residential customers being lower than the prior year. This was partially offset by a decrease in amortization of prior year surcharge balances.
- A $3.4 million increase in other gas revenues primarily due to amortizations of previously deferred CCA revenues, which began April 1, 2024.

Utility Resource Costs

The following graph presents Avista Utilities' electric resource costs for the three months ended June 30, 2024 and 2023 (dollars in millions):

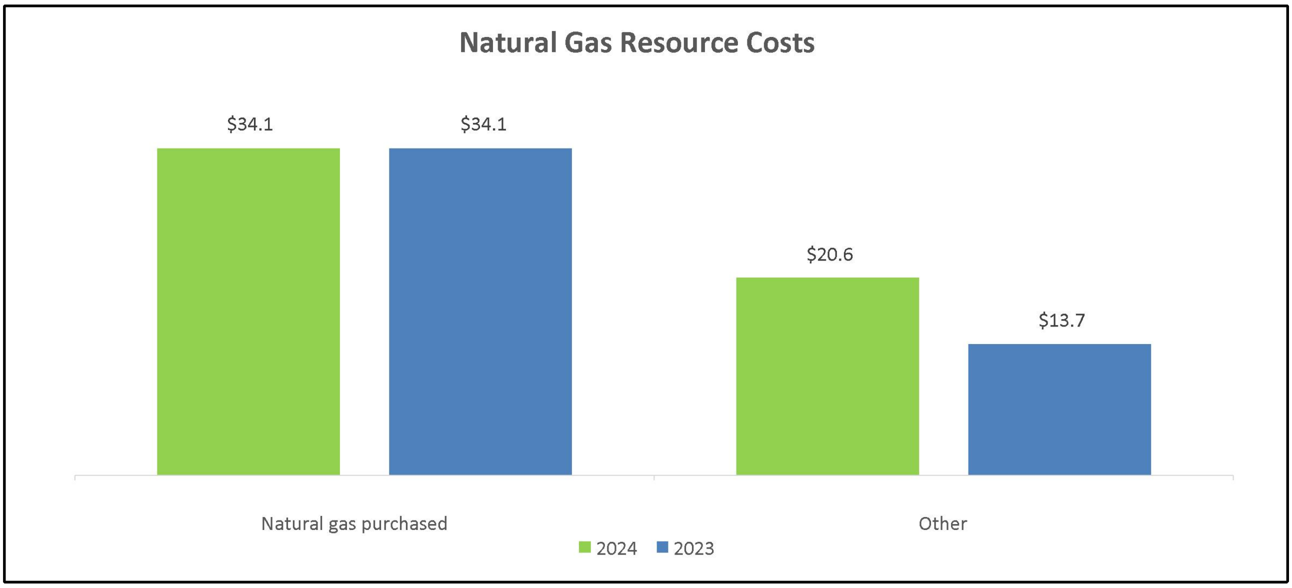


Total electric resource costs in the graph above include intracompany resource costs of $1.4 million and $6.0 million for the three months ended June 30, 2024 and 2023, respectively.

Total electric resource costs decreased $9.2 million for the second quarter of 2024 as compared to the second quarter of 2023. The primary changes that occurred during the period were as follows:

- A $1.2 million decrease in power purchased due to a decrease in the volume of power purchases (decreased costs $7.7 million), partially offset by an increase in wholesale prices (increased costs $6.5 million).
- A $10.0 million decrease in fuel for generation. This was due to a decrease in fuel prices, as well as a decrease in thermal generation during the second quarter, resulting from a decrease in retail and wholesale sales volumes.
- A $3.6 million decrease in other fuel costs. These costs represent fuel and the related derivative instruments purchased for generation which were later sold when conditions indicated it was more economical to sell the fuel as part of the resource optimization process. When the fuel is sold either physically or through a derivative instrument, that revenue is included in sales of fuel.
- A $5.6 million increase in other electric resource costs, related to an increase in amortization of previously deferred costs, partially offset by a decrease in deferred current year power supply costs.

The following graph presents Avista Utilities' natural gas resource costs for the three months ended June 30, 2024 and 2023 (dollars in millions):



Total natural gas resource costs in the graph above include intracompany resource costs of $1.2 million and $2.1 million for the three months ended June 30, 2024 and 2023, respectively.

Total natural gas resource costs increased $6.9 million for the second quarter of 2024 as compared to the second quarter of 2023 primarily due to a decrease in deferred costs during the period, as well as an increase in amortization of previously deferred costs.

Utility Margin

The following table reconciles Avista Utilities' operating revenues, as presented in "Note 16 of the Notes to Condensed Consolidated Financial Statements" to the Non-GAAP financial measure utility margin for the three months ended June 30, 2024 and 2023 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2024	2023	2024	2023	2024	2023	2024	2023
Operating revenues	$ 289,473	$ 283,130	$ 103,950	$ 93,529	$ (2,609)	$ (8,055)	$ 390,814	$ 368,604
Resource costs	91,033	100,291	54,701	47,781	(2,609)	(8,055)	143,125	140,017
Utility margin	$ 198,440	$ 182,839	$ 49,249	$ 45,748	$ —	$ —	$ 247,689	$ 228,587

Electric utility margin increased $15.6 million and natural gas utility margin increased $3.5 million, primarily due to the effects of our general rate cases.

In the second quarter of 2024, we had a $1.3 million pre-tax benefit under the ERM in Washington, compared to a $1.0 million pre-tax benefit for the second quarter of 2023.

Intracompany revenues and resource costs represent purchases and sales of natural gas between our natural gas distribution operations and our electric generation operations (as fuel for our generation plants). These transactions are eliminated in the presentation of total results for Avista Utilities and in the condensed consolidated financial statements but are included in the separate results for electric and natural gas presented above.

Six months ended June 30, 2024 compared to the six months ended June 30, 2023

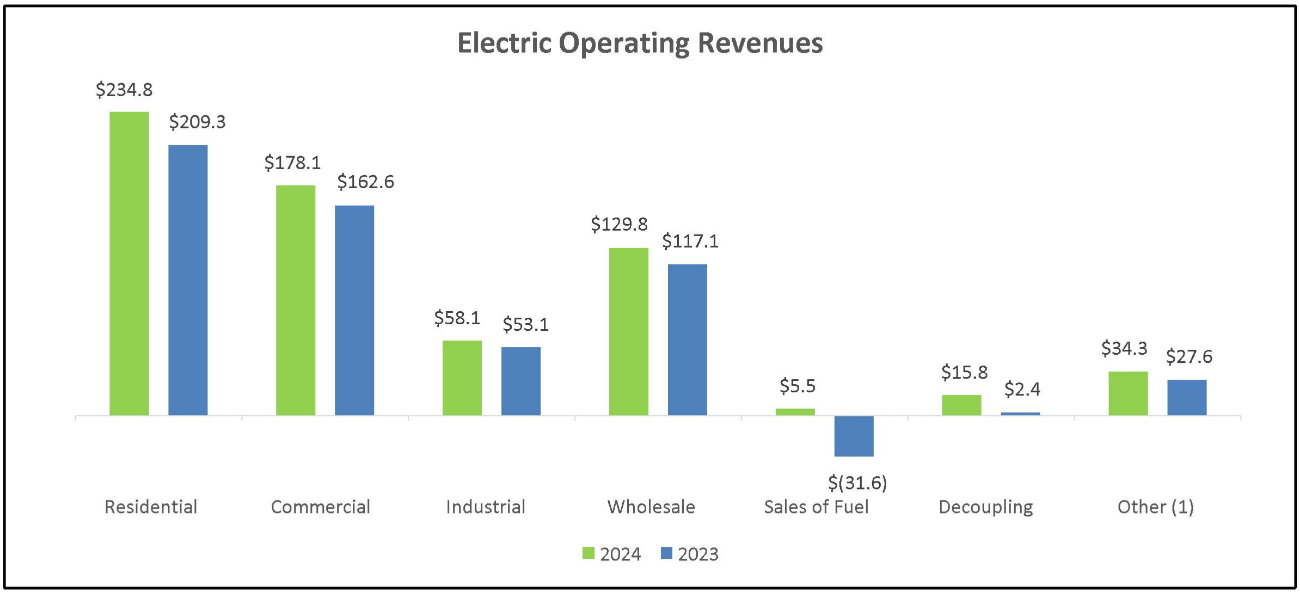
Utility Operating Revenues

Customers

The following table presents Avista Utilities' average number of electric and natural gas retail customers for the six months ended June 30, 2024 and 2023:

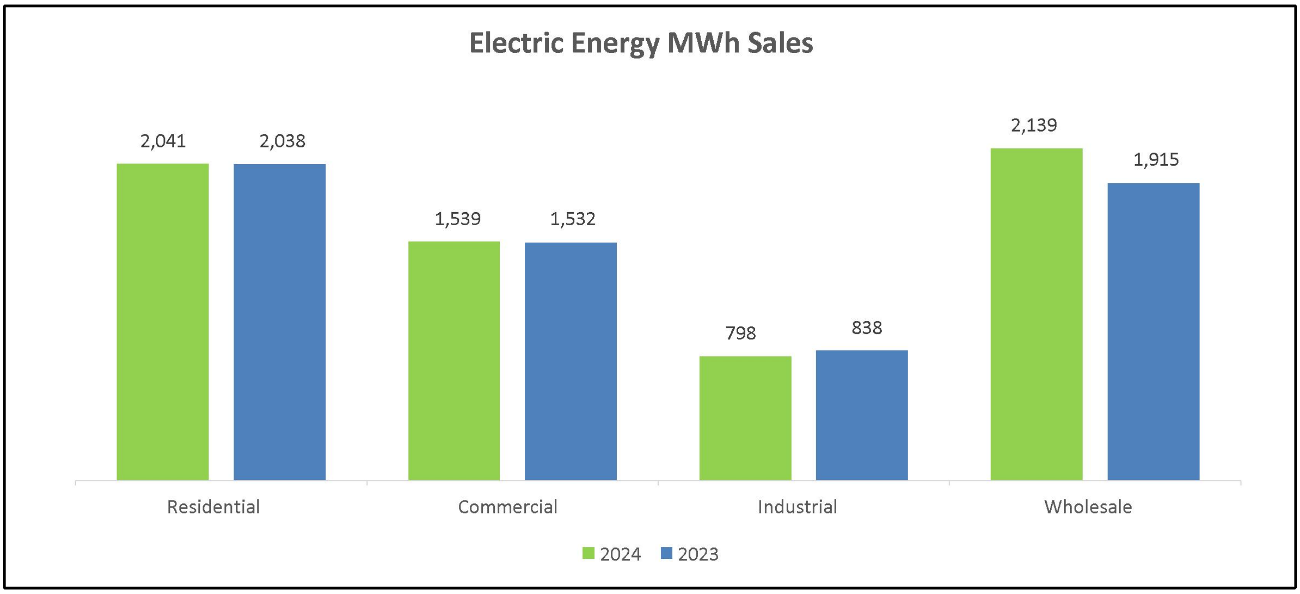
	Electric Customers		Natural Gas Customers	
	2024	2023	2024	2023
Residential	369,616	365,040	342,657	340,073
Commercial	45,923	45,224	37,415	37,101
Interruptible	—	—	51	50
Industrial	1,182	1,189	185	186
Public street and highway lighting	733	688	—	—
Total retail customers	417,454	412,141	380,308	377,410

The following graphs present Avista Utilities' electric operating revenues and megawatt-hour (MWh) sales for the six months ended June 30, 2024 and 2023 (dollars in millions and MWhs in thousands):



(1) This balance includes public street and highway lighting, which is considered part of retail electric revenues.

Total electric operating revenues in the graph above include intracompany sales of $3.1 million and $3.3 million for the six months ended June 30, 2024 and 2023, respectively.



The following table presents the current year decoupling deferrals and the amortization of prior year decoupling deferrals reflected in utility electric operating revenues for the six months ended June 30 (dollars in thousands):

	Electric Decoupling Revenues	
	2024	2023
Current year decoupling deferrals (a)	$ 2,173	$ (2,046)
Amortization of prior year decoupling deferrals (b)	13,655	4,478
Total electric decoupling revenue	$ 15,828	$ 2,432

(a) Positive amounts are increases in decoupling revenue in the current year due to lower customer usage and will be surcharged to customers in future years. Negative amounts are decreases in decoupling revenue in the current year due to higher customer usage and will be rebated to customers in future years.

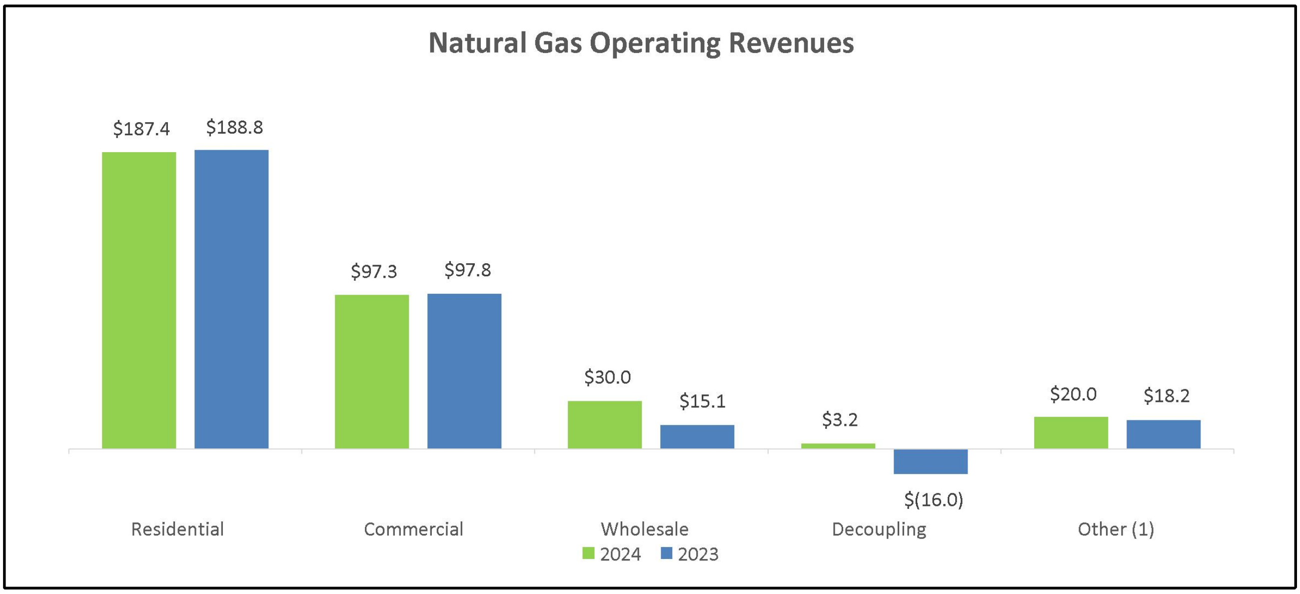
(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years due to higher customer usage and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative amounts are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years due to lower customer usage and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

Total electric revenues increased $115.9 million for the first half of 2024 as compared to the first half of 2023. The primary changes that occurred during the period were as follows:

- A $46.5 million increase in retail electric revenue due to an increase in retail rates (increased revenues by $49.8 million), partially offset by a decrease in MWhs sold (decreased revenues by $3.3 million).
  - Retail rates increased mainly due to the effects of our general rate cases. The ERM surcharge to customers that commenced in July 2023 also increased retail rates.
  - Retail sales volumes decreased primarily due to decreased use by our industrial customers.
- A $12.7 million increase in wholesale electric revenues due to an increase in sales volumes (increased revenues $13.5 million), partially offset by a decrease in sales prices (decreased revenues $0.8 million). The change in volumes was due to increased opportunities to optimize our generation assets based on market conditions.

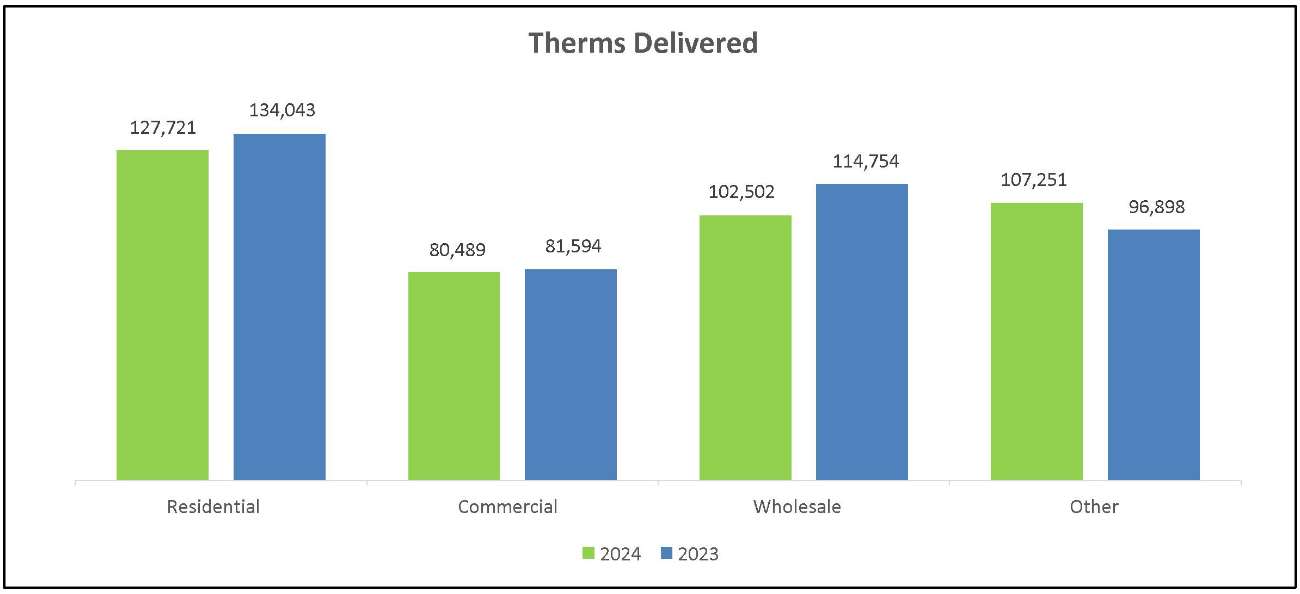
- A $37.1 million increase in sales of fuel as part of thermal generation resource optimization activities, including associated financial hedging activities, which includes net losses on derivative instruments resulting from commodity price volatility early in 2023.
- A $13.4 million increase in electric decoupling revenue, resulting from amortization of larger prior year rebate balances. In addition, there were larger surcharge balances for the current year, as compared to the first half of 2023, resulting from lower usage from residential customers compared to the prior year.

The following graphs present Avista Utilities' natural gas operating revenues and therms delivered for the six months ended June 30, 2024 and 2023 (dollars in millions and therms in thousands):



(1) This balance includes interruptible and industrial revenues, which are considered part of retail natural gas revenues.

Total natural gas operating revenues in the graph above include intracompany sales of $5.4 million and $12.3 million for the six months ended June 30, 2024 and 2023, respectively.



The following table presents the current year decoupling deferrals and the amortization of prior year decoupling deferrals reflected in utility natural gas operating revenues for the six months ended June 30 (dollars in thousands):

	Natural Gas Decoupling Revenues	
	2024	2023
Current year decoupling deferrals (a)	$ 4,445	$ (10,501)
Amortization of prior year decoupling deferrals (b)	(1,219)	(5,457)
Total natural gas decoupling revenue	$ 3,226	$ (15,958)

(a) Positive amounts are increases in decoupling revenue in the current year due to lower customer usage and will be surcharged to customers in future years. Negative amounts are decreases in decoupling revenue in the current year due to higher customer usage and will be rebated to customers in future years.

(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years due to higher customer usage and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative amounts are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years due to lower customer usage and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

Total natural gas revenues increased $34.0 million for the first half of 2024 as compared to the first half of 2023. The primary changes that occurred during the period were as follows:

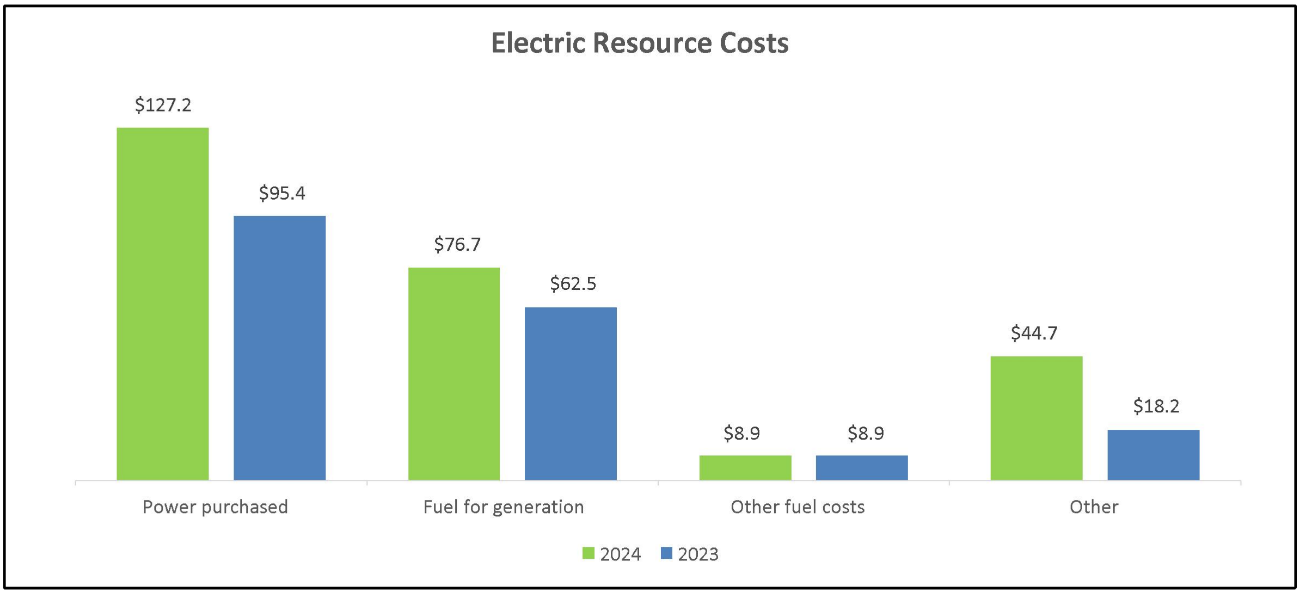
- A $4.4 million decrease in natural gas retail revenues (including industrial, which is included in other) due to decreased sales volumes (decreased revenues $10.5 million), partially offset by higher retail rates (increased revenues $6.1 million)
  - Retail rates increased mainly due to the effects of our general rate cases and rate increases associated with the CCA.
  - Retail natural gas sales volumes decreased primarily due to decreased use by all our customer classes, partially offset by customer growth. Compared to the first half of 2023, residential use per customer decreased 5 percent, commercial use per customer decreased 2 percent and industrial use per customer decreased 10 percent due to warmer weather and decreased heating loads.
- A $14.9 million increase in wholesale natural gas revenues due to an increase in prices (increased revenues $18.5 million), partially offset by a decrease in sales volumes (decreased revenues $3.6 million). The increase in prices

includes the impact of financial losses associated with our hedging activities, which nets with our wholesale revenues. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.

- A $19.2 million increase in natural gas decoupling revenue primarily due to surcharge deferrals in the current year resulting from lower customer usage, compared to rebate deferrals in the prior year. There were also lower amortizations in the current year of prior year refunds, compared to the first half of 2023.

Utility Resource Costs

The following graph presents Avista Utilities' electric resource costs for the six months ended June 30, 2024 and 2023 (dollars in millions):

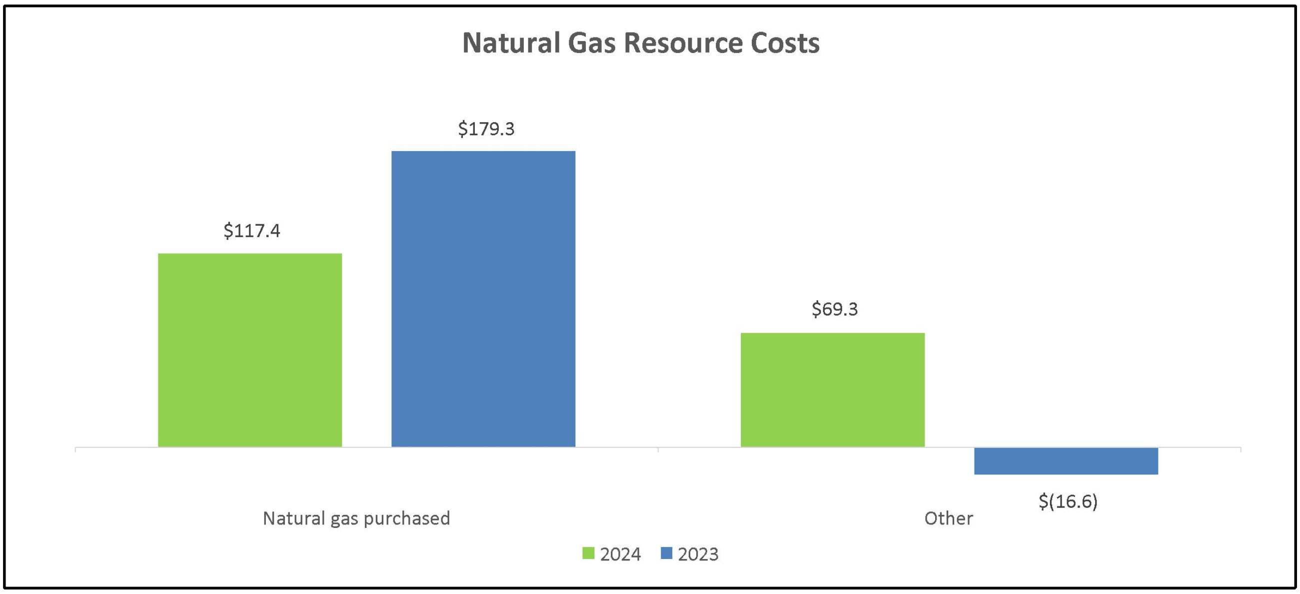


Total electric resource costs in the graph above include intracompany resource costs of $5.4 million and $12.3 million for the six months ended June 30, 2024 and 2023, respectively.

Total electric resource costs increased $72.5 million for the first half of 2024 as compared to the first half of 2023. The primary changes that occurred during the period were as follows:

- A $31.8 million increase in purchased power costs due to an increase in wholesale prices (increased costs $34.2 million), partially offset by a decrease in the volume of power purchases (decreased costs $2.4 million). In mid-January 2024, our service territory experienced much colder than normal weather, requiring purchases at a time when wholesale prices were substantially elevated due to capacity constraints in our region.
- A $14.2 million increase in fuel for generation primarily due to financial gains recognized in the first quarter of 2023 associated with our hedging activities, which net with our physical purchases, as well as increased thermal generation as compared to the prior year, because of higher sales volumes (retail and wholesale activities combined).
- A $26.5 million increase in other electric resource costs related to an increase in amortization of previously deferred costs, as well as an increase in deferrals related to current year power supply costs.

The following graph presents Avista Utilities' natural gas resource costs for the six months ended June 30, 2024 and 2023 (dollars in millions):



Total natural gas resource costs in the graph above include intracompany resource costs of $3.1 million and $3.3 million for the six months ended June 30, 2024 and 2023, respectively.

Total natural gas resource costs increased $24.0 million for the first half of 2024 as compared to the first half of 2023 primarily due to the following:

- A $61.9 million decrease in natural gas purchased due to a decrease in the price of natural gas (decreased costs $54.6 million), and a decrease in volumes (decreased costs $7.3 million). The decrease in the price of natural gas occurred primarily in the first quarter of 2024 due to milder weather (other than a specific January cold event).
- A $85.9 million increase in other primarily related to a decrease in deferred costs during the period, as well as an increase in amortization of previously deferred costs. Deferred costs decreased during the period due to lower natural gas prices, mainly in the first quarter of 2024.

Utility Margin

The following table reconciles Avista Utilities' operating revenues, as presented in "Note 16 of the Notes to Condensed Consolidated Financial Statements" to the Non-GAAP financial measure utility margin for the six months ended June 30, 2024 and 2023 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2024	2023	2024	2023	2024	2023	2024	2023
Operating revenues	$ 656,367	$ 540,427	$ 337,857	$ 303,919	$ (8,474)	$ (15,600)	$ 985,750	$ 828,746
Resource costs	257,387	185,035	186,720	162,719	(8,474)	(15,600)	435,633	332,154
Utility margin	$ 398,980	$ 355,392	$ 151,137	$ 141,200	$ —	$ —	$ 550,117	$ 496,592

Electric utility margin increased $43.6 million and natural gas utility margin increased $9.9 million, primarily due to the effects of general rate cases.

In the first half of 2024, we had a $4.7 million pre-tax expense under the ERM in Washington, compared to a $6.5 million pre-tax expense for the first half of 2023.

Intracompany revenues and resource costs represent purchases and sales of natural gas between our natural gas distribution operations and our electric generation operations (as fuel for our generation plants). These transactions are eliminated in the presentation of total results for Avista Utilities and in the condensed consolidated financial statements but are included in the separate results for electric and natural gas presented above.

Results of Operations - Alaska Electric Light and Power Company

Net income for AEL&P was $1.1 million for the three months ended June 30, 2024 and $1.4 million for the three months ended June 30, 2023. For the first half of 2024, net income was $5.0 million, compared to $5.4 million in 2023. The decrease in net income resulted from increased operating expenses.

Results of Operations - Other Businesses

Our other businesses had a net loss of $2.2 million for the three months ended June 30, 2024 compared to a net loss of $2.7 million for the three months ended June 30, 2023. Net losses were $2.1 million for the first half of 2024, compared to a net loss of $3.5 million in 2023.

The fluctuation in results is primarily related to lower net investment losses due to changes in fair value and recognizing our portion of equity investment losses.

Critical Accounting Policies and Estimates

The preparation of our condensed consolidated financial statements in conformity with GAAP requires us to make estimates and assumptions that affect amounts reported in the condensed consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on our condensed consolidated financial statements and thus, actual results could differ from the amounts reported and disclosed herein. Our critical accounting policies that require the use of estimates and assumptions were discussed in detail in the 2023 Form 10-K and have not changed materially.

Liquidity and Capital Resources

Overall Liquidity

Our sources of overall liquidity and the requirements for liquidity have not materially changed in the six months ended June 30, 2024. See the 2023 Form 10-K for further discussion.

As of June 30, 2024, we had $250.9 million of available liquidity under the Avista Corp. committed line of credit, $43.5 million of available liquidity under our letter of credit facility, and $25.0 million under the AEL&P committed line of credit. With our existing credit facilities and the expected issuances of common stock within the next year, we believe we have adequate liquidity to meet our needs for the next 12 months.

In April 2024, we closed on the remarketing of $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds due in 2032 and 2034, respectively. The proceeds from the remarketing of these bonds were used to repay borrowings under our committed line of credit.

Review of Condensed Consolidated Cash Flow Statement

Operating Activities

Net cash provided by operating activities was $317.0 million for the six months ended June 30, 2024, compared to $269.6 million for the six months ended June 30, 2023. Contributing to the increase are power and natural gas deferrals being amortized and recovered from customers in the first half of 2024, compared to large deferrals in 2023. The net impact of these deferrals on operating cash flows was a $106.2 million increase in 2024 compared to 2023. The change in accounts payable balances during the period also contributed $62.2 million to the increased operating cash flows, as there were large balances paid during the first half of 2023 associated with elevated commodity prices at the end of 2022. These increases were partially offset by a $98.1 million decrease in collateral returned related to our derivative instruments and a $52.0 million decrease related to the change in accounts receivable, both of which were also impacted by elevated commodity prices at the end of 2022.

Investing Activities

Net cash used in investing activities was $254.1 million for the six months ended June 30, 2024, compared to $234.1 million for the six months ended June 30, 2023. We paid $251.2 million for utility capital expenditures in 2024, compared to $226.7 million in 2023.

Financing Activities

Net cash used in financing activities was $83.2 million for the six months ended June 30, 2024, compared to financing activities of $33.2 million for the six months ended June 30, 2023. In the first half of 2024, we issued $83.7 million of long-term debt, compared to $250.0 million in the first half of 2023. We also decreased our short-term borrowings by $105.0 million in the six months ended June 30, 2024, compared to $260.0 million in the six months ended June 30, 2023. In addition, we issued $17.6 million of common stock and paid $75.1 million in dividends in 2024, compared to issuing common stock of $59.5 million and paying $70.0 million in dividends in 2023.

Capital Resources

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings consisted of the following as of June 30, 2024 and December 31, 2023 (dollars in thousands):

	June 30, 2024		December 31, 2023	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt and leases	$ 22,994	0.4 %	$ 22,890	0.4 %
Short-term borrowings	244,000	4.4 %	349,000	6.3 %
Long-term debt to affiliated trusts	51,547	0.9 %	51,547	0.9 %
Long-term debt and leases	2,700,562	48.7 %	2,618,012	47.4 %
Total debt	3,019,103	54.4 %	3,041,449	55.0 %
Total shareholders' equity	2,527,239	45.6 %	2,485,323	45.0 %
Total	$ 5,546,342	100.0 %	$ 5,526,772	100.0 %

Our shareholders' equity increased $41.9 million during the first half of 2024 primarily due to net income and the issuance of common stock, which was partially offset by dividends paid.

Short Term Borrowings

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $500 million and an expiration date of June 2028, with the option to extend for an additional one year period (subject to customary conditions).

We also have a continuing letter of credit agreement in the aggregate amount of $50 million. Either party may terminate the agreement at any time.

In December 2022, we entered into a revolving credit agreement in the amount of $100 million, which was terminated in June 2023.

The following table summarizes the balances outstanding and available liquidity as of June 30, 2024 (dollars in thousands):

	Amount of Facility	Borrowings Outstanding	Letters of Credit Outstanding (1)	Available Liquidity
Line of Credit expiring June 2028	$ 500,000	$ 244,000	$ 5,100	$ 250,900
Letter of Credit Facility	50,000	N/A	6,500	43,500
Total	$ 550,000	$ 244,000	$ 11,600	$ 294,400

(1) Letters of credit are not reflected on the Condensed Consolidated Balance Sheets. If a letter of credit were drawn upon by the holder, we would have an immediate obligation to reimburse the bank that issued that letter.

The Avista Corp. credit facilities contain customary covenant and default provisions, including a change in control (as defined in the agreements). The events of default under each of the credit facilities also include a cross default from other indebtedness (as defined) and, in the case of the letter of credit agreement, other obligations. The committed line of credit agreement also includes a covenant which does not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 65 percent at any time. As of June 30, 2024, we were in compliance with this covenant with a ratio of 54.4 percent.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under Avista Corp.'s lines of credit were as follows as of and for the six months ended June 30 (dollars in thousands):

	2024	2023
$500 million line of credit, expiring June 2028		
Maximum balance outstanding during the period	$ 349,000	$ 334,500
Average balance outstanding during the period	259,824	259,202
Average interest rate during the period	6.46 %	5.73 %
Average interest rate at end of the period	6.55 %	6.24 %
$100 million line of credit, terminated June 2023		
Maximum balance outstanding during the period (1)	N/A	15,000
Average balance outstanding during the period (1)	N/A	283
Average interest rate during the period (1)	N/A	7.75 %

(1) Amounts for the period are through the termination date of June 8, 2023.

AEL&P

AEL&P has a $25.0 million committed line of credit that expires in June 2028. As of June 30, 2024, there was no balance outstanding under this committed line of credit.

The AEL&P credit facility contains customary covenants and default provisions including a covenant which does not permit the ratio of "consolidated total debt at AEL&P" to "consolidated total capitalization at AEL&P" (including the impact of the Snettisham obligation) to be greater than 67.5 percent at any time. As of June 30, 2024, AEL&P was in compliance with this covenant with a ratio of 47.1 percent.

As of June 30, 2024, Avista Corp. and its subsidiaries were in compliance with all of the covenants of their financing agreements, and none of Avista Corp.'s subsidiaries constituted a "significant subsidiary" as defined in Avista Corp.'s committed line of credit.

See "Note 8 of the Notes to Condensed Consolidated Financial Statements" for additional information regarding our short-term borrowing arrangements.

Liquidity Expectations

During April 2024, we remarketed revenue bonds previously held by us, resulting in an additional $83.7 million of long-term debt. We do not expect to issue any additional long-term debt in 2024. We expect to issue $70 million of common stock in 2024 (including $17.6 million issued through June 30, 2024).

Capital Expenditures

We are making capital investments to enhance service and system reliability for our customers and replace aging infrastructure, and expect Avista Utilities' capital expenditures to be $500 million in 2024. See the 2023 Form 10-K for further information on our expected capital expenditures.

Pension Plan

Avista Utilities

In the six months ended June 30, 2024 we contributed $6.7 million to the pension plan. We expect to contribute $10.0 million total for the year. We expect to contribute a total of $40.0 million to the pension plan in the period 2025 through 2028, with an annual contribution of $10.0 million.

The final determination of pension plan contributions for future periods is subject to multiple variables, most of which are beyond our control, including changes to the fair value of pension plan assets, changes in actuarial assumptions (in particular the discount rate used in determining the benefit obligation), or changes in federal legislation. We may change our pension plan contributions in the future depending on changes to any variables, including those listed above.

See "Note 6 of the Notes to Condensed Consolidated Financial Statements" for additional information regarding the pension plan.

Environmental Issues and Contingencies

Our environmental issues and contingencies disclosures have not materially changed during the six months ended June 30, 2024 except as follows:

Washington State Building Codes

In April 2022, the Washington State Building Code Council (SBCC) approved a revised energy code requiring most new commercial buildings and large multifamily buildings to install all-electric space heating. An amendment to the code allows for natural gas to supplement electric heat pumps. In addition, in November 2022, the SBCC approved new building and energy codes for residential housing, requiring new residential buildings in Washington to use electricity as the primary heat source.

Both the commercial and residential building and energy codes were the subject of legal challenges in both Washington State Superior Court (the State Action) and in the Federal District Court for the Eastern District of Washington (the Federal Action). In the Federal Action, to which the Company was a party, the plaintiffs challenged the amendments on the grounds that they were preempted by the federal Energy Policy and Conservation Act (EPCA), citing the Ninth Circuit’s decision in California Restaurant Association v. Berkeley (the Berkeley Decision), which involved similar restrictions on the use of natural gas in new construction in Berkeley, California.

In May 2023, the SBCC voted to delay the effective date of the code amendments and commenced an emergency rulemaking process to evaluate additional amendments to the code in light of the Berkeley Decision. As a result of this action, in July 2023, the Federal District Court declined to issue a preliminary injunction to prevent the amendments from taking effect. The plaintiffs in the Federal Action subsequently dismissed the action, without prejudice to their ability to refile after the SBCC rulemaking process is complete.

The SBCC has since voted to approve revised residential and commercial energy regulations that continue to require new residential and commercial buildings in Washington to use electricity as the primary heat source. In light of this action, the plaintiffs in the State Action amended their complaint to challenge the new regulations. The State Action remains pending.

In May 2024, we, along with Cascade Natural Gas Corporation, Northwest Natural Gas Company, and a coalition of homebuilders, heating unit dealers and other parties, filed a lawsuit challenging the approved building codes on the grounds that they are preempted by EPCA. The lawsuit was filed in the United States District Court for the Western District of Washington. This lawsuit remains pending.

Over time, the building code changes would likely have an adverse impact on our natural gas business and natural gas customers but could also have a positive effect on our electric business. While we are in the process of studying the implications of the changes on our business, at this time we are not able to quantify the likely net effect, positive or negative, on our overall results of operations over the long term. However, the changes would clearly require that additional generating capacity be available to utilities and customers in Washington state.

Washington Climate Commitment Act

The CCA, and its implementing regulations, established a cap and trade program to reduce GHG emissions and achieve the GHG limits previously established under state law. The final rules implement a cap on emissions, provide mechanisms for the sale and tracking of tradable emissions allowances and establish additional compliance and accountability measures. The state issues allowances necessary to serve our Washington retail electric load; off-system wholesale sales may result in additional obligation costs. The CCA also has direct impacts on our Idaho electric operations as it applies to power that is delivered in Washington but is allocated to Idaho customers (wholesale sales) or power generated in Washington that is ultimately delivered to Idaho customers. In May 2023, a "lesser-than" model was approved for use in calculating the allowances needed for compliance that assumes hydroelectric generation is first used for wholesale sales, therefore reducing the number of allowances required. Annually, the model and its resulting calculations must be certified by an independent third party and submitted to the Washington Department of Ecology (Ecology) for approval. If the independent third party or Ecology disagrees with the approach or any of the calculations, it could result in a change to the number of allowances needed for compliance and could result in changes to anticipated costs for our electric operations. For Washington electric, we are allowed to defer any incremental costs associated with the CCA in accordance with our regulatory accounting order; however, in Idaho we are not allowed to pass any costs associated CCA compliance to Idaho customers.

For our Washington natural gas operations, we expect additional financial burdens associated with compliance which will be deferred in accordance with our regulatory accounting order in Washington (see "Executive Overview" for discussion of the CCA).

In December 2023, PacifiCorp filed suit in the United States District Court for the Western District of Washington challenging the CCA as in violation of the dormant commerce clause of the United States Constitution. In its complaint, PacifiCorp was seeking declaratory and injunctive relief. In January 2024, PacifiCorp filed a motion for injunctive relief to enjoin Ecology from enforcing portions of the CCA. On July 15, 2024, the Court denied PacifiCorp’s motion for injunctive relief and dismissed its claims as a matter of law, finding that differing treatment of in-state retail power and wholesale and out of state retail power under the CCA was not unconstitutional under the facts presented.

SEC Climate Disclosure Rules

In March 2024, the SEC adopted final rules requiring certain climate disclosures to be incorporated into SEC filings. The final rules as written are effective for our filings starting with the 2025 Annual Report on Form 10-K.

After the final rules were published by the SEC, multiple lawsuits were made, including allegations that the SEC does not have statutory rulemaking authority over climate reporting, among other various allegations. The SEC requested the cases be consolidated into one action, and the consolidated action is now before the United States Circuit Court of Appeals for the Eighth Circuit.

In April 2024, the SEC voluntarily stayed the implementation of the final rules. In the stay order, the SEC noted it intends to vigorously defend the validity of the final rules.

EPA Regulations for Power Plants

On April 25, 2024, the EPA released a package of final regulations addressed to electric generation facilities. These include:

- *Greenhouse gas regulations for new natural gas-based turbines and existing coal-based units, pursuant to section 111 of the Clean Air Act*. This rule finalizes (a) the repeal of the Affordable Clean Energy rule; (b) guidelines for GHG emissions from existing fossil fuel-fired steam generating electric generating units; and (c) revisions to existing performance standards for new, reconstructed or heavily modified fossil fuel-fired stationary combustion turbine electric generating units.
- *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELG Rule)*. The ELG Rule applies to wastewater discharges from coal-based generating units and establishes pollution control requirements. The Rule builds upon the 2015 and 2020 ELG Rules. It includes a subcategory of requirements for coal plants that will be retired or repowered by the end of 2028 and provides additional compliance pathways for coal plants that retire by the end of 2034.
- *Updated Mercury and Air Tox Standards, pursuant to section 112 of the Clean Air Act (MATS Rule)*. The MATS Rule sets emissions limits for filterable particulate matter for coal-based generating units. The Rule reduces those limits from the standards that were originally set in 2012.
- *Disposal of Coal Combustion Residuals from Electric Utilities – Legacy CCR Surface Impoundments (CCR Rule)*. The CCR Rule builds on 2015 regulations, which apply to active power plants that dispose of coal combustion residuals in

surface impoundments or landfills, by regulating inactive surface impoundments at inactive power plants and CCR management units at active and inactive power plants.

We are in the process of analyzing each of these rules to assess the impact, if any, it may have on our existing generating units, including Colstrip and/or our natural gas-fired generating units. At this time, there are no indications that the implementation of these rules would impact our agreement to transfer our Colstrip ownership to NorthWestern, which is planned to close on December 31, 2025. Along with the other owners (including the operator), we have assessed the CCR Rule and believe there will not be a material change to our asset retirement obligation for Colstrip.

To the extent these regulations result in increased compliance costs, we expect to seek recovery of those costs through the ratemaking process.

See the 2023 Form 10-K for further discussion of our environmental issues and contingencies.

Enterprise Risk Management

The material risks to our businesses, and our mitigation process and procedures to address these risks, were discussed in our 2023 Form 10-K and have not materially changed during the six months ended June 30, 2024. See the 2023 Form 10-K.

Financial Risk

Our financial risks have not materially changed during the six months ended June 30, 2024. Refer to the 2023 Form 10-K. The financial risks included below are required interim disclosures, even if they have not materially changed from December 31, 2023.

Interest Rate Risk

We use a variety of techniques to manage our interest rate risks. We have an interest rate risk policy and a policy to limit our variable rate exposures to a percentage of total capitalization. Additionally, interest rate risk is managed by monitoring market conditions when timing the issuance of long-term debt and optional debt redemptions and establishing fixed rate long-term debt with varying maturities. See "Note 5 of the Notes to Condensed Consolidated Financial Statements" for a summary of our interest rate swap derivatives outstanding as of June 30, 2024 and December 31, 2023 and the amount of additional collateral we would have to post in certain circumstances.

Credit Risk

Under the terms of interest rate swap derivatives, we may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the instrument. A downgrade in our credit ratings could further impact the amount of collateral required. See “Credit Ratings” in the 2023 Form 10-K for further information. As of June 30, 2024, we had interest rate swap derivatives outstanding with a notional amount totaling $10.0 million and we had no cash deposited as collateral and no letters of credit outstanding for these interest rate swap derivatives. If our credit ratings were lowered to below “investment grade” based on our interest rate swap derivatives outstanding at June 30, 2024, we would not be required to post additional collateral because all of our outstanding interest rate swaps were in an asset position at the time.

As of June 30, 2024, we had cash deposited as collateral of $23.9 million and letters of credit of $6.9 million outstanding related to our energy contracts. Price movements and/or a downgrade in our credit ratings or other established credit criteria could impact further the amount of collateral required. See “Credit Ratings” in the 2023 Form 10-K for further information. For example, in addition to limiting our ability to conduct transactions, if our credit ratings were lowered to below “investment grade” based on our positions outstanding at June 30, 2024 (including contracts considered derivatives and those considered non-derivatives), we would potentially be required to post the following additional collateral (in thousands):

	June 30, 2024
Additional collateral taking into account contractual thresholds	$ 9,786
Additional collateral without contractual thresholds	27,896

Energy Commodity Risk

Our energy commodity risks have not materially changed during the six months ended June 30, 2024. See the 2023 Form 10-K. The following table presents energy commodity derivative fair values as a net asset or (liability) as of June 30, 2024 expected to be delivered in each respective year (dollars in thousands). There are no expected deliveries of energy commodity derivatives after 2027.

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
Remainder 2024	$ 481	$ (664)	$ (9,184)	$ (14,760)	$ 2,250	$ 1,199	$ (2,695)	$ (1,577)
2025	—	—	(9,776)	(6,755)	1,381	683	(5,312)	(1,604)
2026	—	—	(3,494)	(1,366)	—	—	—	—
2027	—	—	(372)	(39)	—	—	—	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2023 expected to be delivered in each respective year (dollars in thousands). There were no expected deliveries of energy commodity derivatives after 2026.

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
2024	$ 746	$ —	$ (7,485)	$ (50,899)	$ 6,990	$ 1,502	$ (3,495)	$ 1,222
2025	—	—	(5,781)	(5,166)	—	295	(4,349)	(1,348)
2026	—	—	(940)	(431)	—	—	—	—

(1) Physical transactions represent commodity transactions where we will take or make delivery of either electricity or natural gas; financial transactions represent derivative instruments with delivery of cash in the amount of the benefit or cost but with no physical delivery of the commodity, such as futures, swap derivatives, options, or forward contracts.

The above electric and natural gas derivative contracts will be included in either power supply costs or natural gas supply costs during the period they are delivered and will be included in deferral and recovery mechanisms (ERM, PCA, and PGAs), or in the general rate case process, and are expected to eventually be collected through retail rates from customers.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The information required by this item is set forth in the Enterprise Risk Management section of "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" and is incorporated herein by reference.

Item 4. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended) (Act) that are designed to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company's management, including its principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. With the participation of the Company's principal executive officer and principal financial officer, the Company's management evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures are effective at a reasonable assurance level as of June 30, 2024.

There have been no changes in the Company's internal control over financial reporting that occurred during the second quarter of 2024 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. Other Information

Item 1. Legal Proceedings

See “Note 15 of Notes to Condensed Consolidated Financial Statements” in “Part I. Financial Information Item 1. Condensed Consolidated Financial Statements.”

Item 1A. Risk Factors

Refer to the 2023 Form 10-K for disclosure of risk factors that could have a significant impact on our results of operations, financial condition or cash flows and could cause actual results or outcomes to differ materially from those discussed in our reports filed with the SEC (including this Quarterly Report on Form 10-Q), and elsewhere. These risk factors have not materially changed from the disclosures provided in the 2023 Form 10-K.

Item 5. Other Information

During the fiscal quarter ended June 30, 2024, none of our directors or officers informed us of the adoption or termination of a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as those terms are defined in Regulation S-K, Item 408.

Item 6. Exhibits

15	Letter Re: Unaudited Interim Financial Information (1)
31.1	Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002) (1)
31.2	Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002) (1)
32	Certification of Corporate Officers (Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002) (2)
101.INS	Inline XBRL Instance Document. The instance document does not appear in the interactive data file because its inline XBRL tags are embedded within the inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema With Embedded Linkbase Documents
104	Cover page formatted as Inline XBRL and contained in Exhibit 101.

(1) Filed herewith.

(2) Furnished herewith.

SIGNATURE

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

AVISTA CORPORATION
(Registrant)

Date: August 6, 2024

/s/ Kevin J. Christie
Kevin J. Christie
Senior Vice President, Chief Financial Officer,
Treasurer and Regulatory Affairs Officer
(Principal Financial Officer)

Exhibit 15

August 6, 2024

To the Board of Directors and Shareholders of Avista Corporation
1411 East Mission Ave
Spokane, Washington 99202

We are aware that our report dated August 6, 2024, on our review of interim financial information of Avista Corporation and subsidiaries appearing in this Quarterly report on Form 10-Q for the quarter ended June 30, 2024, is incorporated by reference in Registration Statement Nos. 333-33790, 333-179042 and 333-208986 on Form S-8 and in Registration Statement No. 333-264790 on Form S-3.

/s/ Deloitte & Touche LLP

Portland, Oregon

Exhibit 31.1

CERTIFICATION

I, Dennis P. Vermillion, certify that:

1. I have reviewed this report on Form 10-Q of Avista Corporation;

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

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

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

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

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

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

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

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

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

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

Date: August 6, 2024

/s/ Dennis P. Vermillion

Dennis P. Vermillion

Chief Executive Officer

(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Kevin J. Christie, certify that:

1. I have reviewed this report on Form 10-Q of Avista Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 6, 2024

/s/ Kevin J. Christie

Kevin J. Christie
Senior Vice President, Chief Financial Officer,
Treasurer and Regulatory Affairs Officer
(Principal Financial Officer)

Exhibit 32

AVISTA CORPORATION

CERTIFICATION OF CORPORATE OFFICERS

(Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the

Sarbanes-Oxley Act of 2002)

Each of the undersigned, Dennis P. Vermillion, President and Chief Executive Officer of Avista Corporation (the “Company”), and Kevin J. Christie, Senior Vice President, Chief Financial Officer, Treasurer and Regulatory Affairs Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2024 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 6, 2024

/s/ Dennis P. Vermillion

Dennis P. Vermillion
Chief Executive Officer

/s/ Kevin J. Christie

Kevin J. Christie
Senior Vice President, Chief Financial Officer,
Treasurer and Regulatory Affairs Officer