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, 2019 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, 2019, 66,111,437 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

AVISTA CORPORATION
INDEX

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
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
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)
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
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).
Hydro One	-	Hydro One Limited, based in Toronto, Ontario, Canada
IPUC	-	Idaho Public Utilities Commission
Juneau	-	The City and Borough of Juneau, Alaska
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
SEC	-	U.S. Securities and Exchange Commission
TCJA	-	The "Tax Cuts and Jobs Act," signed into law on December 22, 2017
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 that are 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:

Financial 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;
- our ability to obtain financing through the issuance of debt and/or equity securities, which can 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, our ability to effectively hedge interest rates for anticipated debt issuances, variable interest rate borrowing and the extent to which we recover interest costs through retail rates collected from customers;
- changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension and other postretirement benefit plans, which can affect future funding obligations, pension and other postretirement benefit expense and the related liabilities;
- deterioration in the creditworthiness of our customers;
- 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;
- declining energy demand related to customer energy efficiency, conservation measures and/or increased distributed generation;
- changes in the long-term climate and weather may 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;
- industry and geographic concentrations which may increase our exposure to credit risks due to counterparties, suppliers and customers being similarly affected by changing conditions;

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, interest rate swap derivatives, 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;

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 can 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 to us from such transactions, and the market value of derivative assets and liabilities;
- default or nonperformance on the part of any 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 may 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;

Operational Risk

- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, snow and ice storms, that can disrupt energy generation, transmission and distribution, as well as the availability and costs of fuel, materials, equipment, supplies and support services;
- explosions, fires, accidents, mechanical breakdowns or other incidents that may impair assets and may disrupt operations of any of our generation facilities, transmission, and electric and natural gas distribution systems or other operations and may require us to purchase replacement power;
- explosions, fires, accidents or other incidents arising from or allegedly arising from our operations that may cause wildfires, 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 may disrupt or cause damage to our utility assets or to the national or regional economy in general, including any effects of terrorism, cyberattacks or vandalism that damage or disrupt information technology systems;
- 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;
- 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;
- 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 overbuild 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 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 any other electrical grids and the cost of replacement power (diesel);
- changing river regulation or operations at hydroelectric facilities not owned by us, which could impact our hydroelectric facilities downstream;
- change in the use, availability or abundancy of water resources and/or rights needed for operation of our hydroelectric facilities;

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;
- the ability to comply with the terms of the licenses and permits for our hydroelectric or thermal generating facilities at cost-effective levels;

Cyber and Technology Risk

- cyberattacks on the operating systems that are 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 that are 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, which could result in the disruption of business operations, the release of private information and the incurrence of liabilities and costs;
- changes in costs that impede our ability to effectively 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;
- 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 and the extent to which new uses for our services may materialize or existing uses may decline, 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 may 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;
- entering into or growth of non-regulated activities may increase earnings volatility;
- potential legal proceedings arising from the termination of the proposed acquisition of the Company by Hydro One;

External Mandates Risk

- changes in environmental laws, regulations, decisions and policies, including 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 or restrictions on greenhouse gas emissions to mitigate concerns over global climate changes;
- 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 coal-fired power generation and opposition to other thermal generation, wind turbines or hydroelectric facilities;
- wholesale and retail competition including alternative energy sources, growth in customer-owned power resource technologies that displace utility-supplied energy or that may be sold back to the utility, and alternative energy suppliers and delivery arrangements;
- failure to identify changes in legislation, taxation and regulatory issues that are 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; and

- the risk of municipalization in any of our service territories.

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 that 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 that any such factor or combination of factors may cause actual results to differ materially from those contained in any forward-looking statement.

Available Information

Our website address is www.myavista.com. We make annual, quarterly and current reports available on our website as soon as practicable after electronically filing these reports with the SEC. The SEC maintains a website that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC at www.sec.gov. Except for SEC filings or portions thereof that are 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,	
	2019	2018	2019	2018
Operating Revenues:				
Utility revenues:				
Utility revenues, exclusive of alternative revenue programs	$ 288,826	$ 309,134	$ 682,067	$ 717,490
Alternative revenue programs	9,725	3,570	5,067	(2,369)
Total utility revenues	298,551	312,704	687,134	715,121
Non-utility revenues	2,261	6,594	10,159	13,538
Total operating revenues	300,812	319,298	697,293	728,659
Operating Expenses:				
Utility operating expenses:				
Resource costs	88,439	105,969	225,786	260,587
Other operating expenses	87,720	81,078	171,698	158,376
Merger transaction costs	11	983	19,675	1,655
Depreciation and amortization	55,479	45,651	104,393	90,384
Taxes other than income taxes	22,908	25,596	54,851	56,425
Non-utility operating expenses:				
Other operating expenses	6,332	6,543	13,687	13,367
Depreciation and amortization	155	199	364	380
Total operating expenses	261,044	266,019	590,454	581,174
Income from operations	39,768	53,279	106,839	147,485
Interest expense	25,511	25,170	51,162	49,946
Interest expense to affiliated trusts	351	302	708	555
Capitalized interest	(1,101)	(1,139)	(2,029)	(2,107)
Merger termination fee	—	—	(103,000)	—
Other expense (income)-net	(8,268)	(1,907)	(9,175)	2,572
Income before income taxes	23,275	30,853	169,173	96,519
Income tax expense (benefit)	(1,741)	5,209	28,276	15,919
Net income	25,016	25,644	140,897	80,600
Net loss (income) attributable to noncontrolling interests	303	(67)	216	(133)
Net income attributable to Avista Corp. shareholders	$ 25,319	$ 25,577	$ 141,113	$ 80,467
Weighted-average common shares outstanding (thousands), basic	65,894	65,677	65,814	65,658
Weighted-average common shares outstanding (thousands), diluted	65,963	65,983	65,883	65,957
Earnings per common share attributable to Avista Corp. shareholders:				
Basic	$ 0.38	$ 0.39	$ 2.14	$ 1.23
Diluted	$ 0.38	$ 0.39	$ 2.14	$ 1.22

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,	
	2019	2018	2019	2018
Net income	$ 25,016	$ 25,644	$ 140,897	$ 80,600
Other Comprehensive Income:				
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $42, $54, $85 and $109 respectively	161	204	321	408
Total other comprehensive income	161	204	321	408
Comprehensive income	25,177	25,848	141,218	81,008
Comprehensive loss (income) attributable to noncontrolling interests	303	(67)	216	(133)
Comprehensive income attributable to Avista Corporation shareholders	$ 25,480	$ 25,781	$ 141,434	$ 80,875

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands
(Unaudited)

	June 30, 2019	December 31, 2018
Assets:		
Current Assets:		
Cash and cash equivalents	$ 17,231	$ 14,656
Accounts and notes receivable-less allowances of $3,415 and $5,233, respectively	115,493	165,824
Materials and supplies, fuel stock and stored natural gas	67,659	63,881
Regulatory assets	38,785	48,552
Other current assets	30,599	54,010
Total current assets	269,767	346,923
Net utility property	4,684,654	4,648,930
Goodwill	52,426	57,672
Non-current regulatory assets	630,451	614,354
Other property and investments-net and other non-current assets	240,630	114,697
Total assets	$ 5,877,928	$ 5,782,576
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 80,619	$ 108,372
Current portion of long-term debt and capital leases	104,993	107,645
Short-term borrowings	169,000	190,000
Regulatory liabilities	37,954	113,209
Other current liabilities	124,169	120,358
Total current liabilities	516,735	639,584
Long-term debt and capital leases	1,701,434	1,755,529
Long-term debt to affiliated trusts	51,547	51,547
Pensions and other postretirement benefits	214,983	222,537
Deferred income taxes	508,139	487,602
Non-current regulatory liabilities	789,655	780,701
Other non-current liabilities and deferred credits	211,401	71,031
Total liabilities	3,993,894	4,008,531
Commitments and Contingencies (See Notes to Condensed Consolidated Financial Statements)		
Equity:		
Avista Corporation Shareholders’ Equity:		
Common stock, no par value; 200,000,000 shares authorized; 66,111,317 and 65,688,356 shares issued and outstanding, respectively	1,157,024	1,136,491
Accumulated other comprehensive loss	(7,545)	(7,866)
Retained earnings	734,555	644,595
Total Avista Corporation shareholders’ equity	1,884,034	1,773,220
Noncontrolling Interests	—	825
Total equity	1,884,034	1,774,045
Total liabilities and equity	$ 5,877,928	$ 5,782,576

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

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

	2019	2018
Operating Activities:		
Net income	$ 140,897	$ 80,600
Non-cash items included in net income:		
Depreciation and amortization	104,757	92,584
Deferred income tax provision and investment tax credits	5,577	(1,272)
Power and natural gas cost amortizations (deferrals), net	(47,716)	6,701
Amortization of debt expense	1,338	1,635
Amortization of investment in exchange power	1,225	1,225
Stock-based compensation expense	7,009	3,878
Equity-related AFUDC	(3,253)	(2,845)
Pension and other postretirement benefit expense	18,040	16,025
Other regulatory assets and liabilities and deferred debits and credits	1,122	21,323
Change in decoupling regulatory deferral	(5,444)	2,226
Gain on sale of METALfx (before payment of transaction costs)	(6,477)	—
Other	(3,904)	2,108
Contributions to defined benefit pension plan	(14,600)	(14,600)
Cash paid for settlement of interest rate swap agreements	—	(31,484)
Cash received for settlement of interest rate swap agreements	—	5,594
Changes in certain current assets and liabilities:		
Accounts and notes receivable	47,771	65,843
Materials and supplies, fuel stock and stored natural gas	(7,225)	1,174
Collateral posted for derivative instruments	47,352	44,080
Other current assets	(8,783)	3,832
Accounts payable	(19,393)	(21,642)
Other current liabilities	(5,622)	(1,560)
Net cash provided by operating activities	252,671	275,425
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(199,988)	(183,132)
Issuance of notes receivable at subsidiaries	(900)	(2,780)
Equity and property investments made by subsidiaries	(6,624)	(7,431)
Proceeds from sale of METALfx (net of cash sold)	16,407	—
Other	1,072	438
Net cash used in investing activities	(190,033)	(192,905)

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

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

	2019	2018
Financing Activities:		
Net decrease in short-term borrowings	$ (21,000)	$ (105,398)
Proceeds from issuance of long-term debt	—	374,621
Maturity of long-term debt and capital leases	(1,330)	(276,170)
Issuance of common stock, net of issuance costs	14,929	1,227
Cash dividends paid	(51,153)	(49,101)
Other	(1,509)	(8,538)
Net cash used in financing activities	(60,063)	(63,359)
Net increase in cash and cash equivalents	2,575	19,161
Cash and cash equivalents at beginning of period	14,656	16,172
Cash and cash equivalents at end of period	$ 17,231	$ 35,333

The Accompanying Notes are an Integral Part of These Statements.

Table of Contents

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,	
	2019	2018	2019	2018
Common Stock, Shares:				
Shares outstanding at beginning of period	65,749,932	65,668,477	65,688,356	65,494,333
Shares issued	361,385	19,015	422,961	193,159
Shares outstanding at end of period	66,111,317	65,687,492	66,111,317	65,687,492
Common Stock, Amount:				
Balance at beginning of period	$ 1,140,242	$ 1,131,549	$ 1,136,491	$ 1,133,448
Equity compensation expense	2,043	1,760	6,495	3,558
Issuance of common stock, net of issuance costs	14,739	995	14,929	1,227
Payment of minimum tax withholdings for share-based payment awards	—	—	(891)	(3,929)
Balance at end of period	1,157,024	1,134,304	1,157,024	1,134,304
Accumulated Other Comprehensive Loss:				
Balance at beginning of period	(7,706)	(9,628)	(7,866)	(8,090)
Other comprehensive income	161	204	321	408
Reclassification of excess income tax benefits	—	—	—	(1,742)
Balance at end of period	(7,545)	(9,424)	(7,545)	(9,424)
Retained Earnings:				
Balance at beginning of period	734,774	636,468	644,595	604,470
Net income attributable to Avista Corporation shareholders	25,319	25,577	141,113	80,467
Cash dividends paid on common stock	(25,538)	(24,467)	(51,153)	(49,101)
Reclassification of excess income tax benefits	—	—	—	1,742
Balance at end of period	734,555	637,578	734,555	637,578
Total Avista Corporation shareholders' equity	1,884,034	1,762,458	1,884,034	1,762,458
Noncontrolling Interests:				
Balance at beginning of period	912	182	825	656
Net income (loss) attributable to noncontrolling interests	(303)	67	(216)	133
Cash dividends paid to subsidiary noncontrolling interests	—	—	—	(540)
Deconsolidation of noncontrolling interests related to sale of METALfx	(609)	—	(609)	—
Balance at end of period	—	249	—	249
Total equity	$ 1,884,034	$ 1,762,707	$ 1,884,034	$ 1,762,707
Dividends declared per common share	$ 0.3875	$ 0.3725	$ 0.7750	$ 0.7450

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, 2019 and June 30, 2018 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, 2018 (2018 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, most of whom are employees who operate the Company's Noxon Rapids generating facility.

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 all of the subsidiary companies in the non-utility businesses, with the exception of AJT Mining Properties, Inc., which is a subsidiary of AERC. See Note 16 for business segment information. See Note 18 for discussion of the sale of METALfx, an unregulated subsidiary of the Company.

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 resulting from its interests in jointly owned plants.

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 have been concluded to be 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 that are 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 that is 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 that allow 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 any 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, 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. As of June 30, 2019, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 15 for further discussion of the Company's commitments and contingencies.

NOTE 2. NEW ACCOUNTING STANDARDS

ASU No. 2016-02, "Leases (Topic 842)"
ASU No. 2018-01, "Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842"
ASU No. 2018-11, "Leases (Topic 842): Targeted Improvements"

On January 1, 2019, the Company adopted ASU No. 2016-02, which outlines a model for entities to use in accounting for leases and supersedes previous lease accounting guidance, as well as several practical expedients in ASU Nos. 2018-01 and 2018-11.

The Company adopted ASU No. 2016-02 utilizing a modified retrospective adoption method with the "package of three" and hindsight practical expedients offered by the standard. The "package of three" provides for an entity to not reassess at adoption whether any expired or existing contracts are deemed, for accounting purposes, to be or contain leases, the classification of any expired or existing leases, and any initial direct costs for any existing leases. As a result, the Company did not reassess existing or expired contracts under the new lease guidance and it did not reassess the classification of any existing leases. The Company used the benefit of hindsight in determining both term and impairments associated with any existing leases. Use of this practical expedient has resulted in lease terms that best represent management's expectations with respect to use of the underlying asset but did not result in recognition of any impairment.

The Company elected to adopt ASU No. 2018-01, which allows an entity to exclude from application of Topic 842 all easements executed prior to January 1, 2019. In addition, the Company elected to adopt the "comparatives under 840" practical expedient offered in ASU No. 2018-11, which allows an entity to apply the new lease standard at the adoption date, recognizing any necessary cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption and presenting comparative periods in the financial statements under ASC 840 (previous lease accounting guidance). Adoption of the standard did not result in a cumulative effect adjustment within the Company's financial statements.

As allowed by ASU No. 2016-02, the Company elected not to apply the requirements of the standard to short-term leases, those leases with an initial term of 12 months or less. These leases are not recorded on the balance sheet and are immaterial to the financial statements.

Adoption of the standard impacted the Company's Condensed Consolidated Balance Sheet through recognition of right-of-use (ROU) assets and lease liabilities for the Company's operating leases. Accounting for finance leases (formerly capital leases) remained substantially unchanged. See Note 5 for further information on the Company's leases.

ASU No. 2018-02 "Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income"

In February 2018, the FASB issued ASU No. 2018-02, which amended the guidance for reporting comprehensive income. This ASU allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the enactment of the TCJA in December 2017. This ASU became effective for periods beginning after December 15, 2018 and early adoption was permitted. Upon adoption, the requirements of this ASU must be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the TCJA is recognized. The Company early adopted this standard effective January 1, 2018 and elected to apply the guidance during the period of adoption rather than apply the standard retrospectively. As a result, the Company reclassified $1.7 million in tax benefits from accumulated other comprehensive loss to retained earnings during the six months ended June 30, 2018.

ASU 2018-13 "Fair Value Measurement (Topic 820)"

In August 2018, the FASB issued ASU No. 2018-13, which amends the fair value measurement disclosure requirements of ASC 820. The requirements of this ASU include additional disclosure regarding the range and weighted average used to develop significant unobservable inputs for Level 3 fair value estimates and the elimination of certain other previously required disclosures, such as the narrative description of the valuation process for Level 3 fair value measurements. This ASU is effective for periods beginning after December 15, 2019 and early adoption is permitted. Entities have the option to early adopt the eliminated or modified disclosure requirements and delay the adoption of all the new disclosure requirements until the effective date of the ASU. The Company is in the process of evaluating this standard; however, it has determined that it will not early adopt any portion of this standard as of June 30, 2019.

ASU No. 2018-14 "Compensation - Retirement Benefits - Defined Benefit Plans - General (Subtopic 715-20)"

In August 2018, the FASB issued ASU No. 2018-14, which amends ASC 715 to add, remove and/or clarify certain disclosure requirements related to defined benefit pension and other postretirement plans. The additional disclosure requirements are primarily narrative discussion of significant changes in the benefit obligations and plan assets. The removed disclosures are primarily information about accumulated other comprehensive income expected to be recognized over the next year and the effects of changes associated with assumed health care costs. This ASU is effective for periods beginning after December 15, 2021 and early adoption is permitted. The Company is in the process of evaluating this standard; however, it has determined that it will not early adopt this standard as of June 30, 2019.

NOTE 3. BALANCE SHEET COMPONENTS

Materials and Supplies, Fuel Stock and Stored Natural Gas

Inventories of materials and supplies, fuel stock and stored natural gas are recorded at average cost for our regulated operations and the lower of cost or market for our non-regulated operations and consisted of the following as of June 30, 2019 and December 31, 2018 (dollars in thousands):

	June 30, 2019	December 31, 2018
Materials and supplies	$ 46,886	$ 47,403
Fuel stock	6,332	4,869
Stored natural gas	14,441	11,609
Total	$ 67,659	$ 63,881

Other Current Assets

Other current assets consisted of the following as of June 30, 2019 and December 31, 2018 (dollars in thousands):

	June 30, 2019	December 31, 2018
Collateral posted for derivative instruments after netting with outstanding derivative liabilities	$ —	$ 26,809
Prepayments	24,515	17,536
Other	6,084	9,665
Total	$ 30,599	$ 54,010

Net Utility Property

Net utility property consisted of the following as of June 30, 2019 and December 31, 2018 (dollars in thousands):

	June 30, 2019	December 31, 2018
Utility plant in service	$ 6,262,789	$ 6,209,968
Construction work in progress	191,845	160,598
Total	6,454,634	6,370,566
Less: Accumulated depreciation and amortization	1,769,980	1,721,636
Total net utility property	$ 4,684,654	$ 4,648,930

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, 2019 and December 31, 2018 (dollars in thousands):

	June 30, 2019	December 31, 2018
Operating lease ROU assets	$ 70,442	$ —
Finance lease ROU assets	52,800	—
Non-utility property	28,438	31,355
Equity investments	36,921	29,257
Investment in affiliated trust	11,547	11,547
Notes receivable	11,376	11,073
Deferred compensation assets	8,557	8,400
Other	20,549	23,065
Total	$ 240,630	$ 114,697

Other Current Liabilities

Other current liabilities consisted of the following as of June 30, 2019 and December 31, 2018 (dollars in thousands):

	June 30, 2019	December 31, 2018
Accrued taxes other than income taxes	$ 35,502	$ 36,858
Employee paid time off accruals	22,092	20,992
Accrued interest	16,536	16,704
Current portion of pensions and other postretirement benefits	11,175	9,151
Derivative liabilities	9,274	3,908
Other current liabilities	29,590	32,745
Total other current liabilities	$ 124,169	$ 120,358

Other Non-Current Liabilities and Deferred Credits

Other non-current liabilities and deferred credits consisted of the following as of June 30, 2019 and December 31, 2018 (dollars in thousands):

	June 30, 2019	December 31, 2018
Operating lease liabilities	$ 68,228	$ —
Finance lease liabilities	53,150	—
Deferred investment tax credits	31,172	29,725
Asset retirement obligations	18,595	18,266
Derivative liabilities	27,198	10,300
Other	13,058	12,740
Total	$ 211,401	$ 71,031

Regulatory Assets and Liabilities

Regulatory assets and liabilities consisted of the following as of June 30, 2019 and December 31, 2018 (dollars in thousands):

	June 30, 2019		December 31, 2018	
	Current	Non-Current	Current	Non-Current
Regulatory Assets				
Energy commodity derivatives	$ 25,125	$ 10,764	$ 41,428	$ 16,866
Decoupling surcharge	6,498	16,167	3,408	17,501
Pension and other postretirement benefit plans	—	221,454	—	228,062
Interest rate swaps	—	155,787	—	133,854
Deferred income taxes	—	95,217	—	91,188
Settlement with Coeur d'Alene Tribe	—	41,988	—	42,643
Demand side management programs	—	13,705	—	19,674
Utility plant to be abandoned	—	25,273	—	24,334
Other regulatory assets	7,162	50,096	3,716	40,232
Total regulatory assets	$ 38,785	$ 630,451	$ 48,552	$ 614,354
Regulatory Liabilities				
Income tax related liabilities	$ 23,079	$ 418,039	$ 27,997	$ 425,613
Deferred natural gas costs	1,852	—	40,713	—
Deferral power costs	6,612	32,617	25,072	16,933
Decoupling rebate	437	2,861	6,782	204
Utility plant retirement costs	—	302,734	—	297,379
Interest rate swaps	—	17,659	—	28,078
Other regulatory liabilities	5,974	15,745	12,645	12,494
Total regulatory liabilities	$ 37,954	$ 789,655	$ 113,209	$ 780,701

NOTE 4. REVENUE

ASC 606 defines 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. Given that all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized immediately at that time.

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 which are not accounted for as derivatives and, accordingly, are within the scope of ASC 606 and 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 that alternative revenue programs are contracts between an entity and a regulator of utilities, not a contract between an entity and a customer. GAAP requires that an entity present revenue arising from alternative revenue programs separately from revenues arising from contracts with customers on the face of 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 that will be surcharged or rebated to customers in future periods. GAAP requires that for any 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 current period Condensed Consolidated Statement of Income. Any 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 that must be 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.

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 specifically scoped out of ASC 606. As such, these revenues 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 those transactions that are entered into and settled within the same month.

Other Utility Revenue

Other utility revenue includes rent, revenues from the lineman training school, sales of materials, late fees and other charges that do not represent contracts with customers. Other utility revenue also includes the provision for earnings sharing and the deferral and amortization of refunds to customers associated with the TCJA. This revenue is scoped out of ASC 606, 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 that are "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 taxes that are imposed on Avista Utilities as opposed to being imposed on its 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 that were 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,	
	2019	2018	2019	2018
Utility-related taxes	$ 12,688	$ 12,986	$ 31,777	$ 32,153

Non-Utility Revenues

Revenue from Contracts with Customers

Non-utility revenues from contracts with customers are primarily derived from the operations of METALfx (through the date of its sale in April 2019, see Note 18 for further discussion). The contracts associated with METALfx have one performance obligation, the delivery of a product, and revenues are recognized when the risk of loss transfers to the customer, which occurs when products are shipped.

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 does have one capacity agreement where the customer makes payments throughout the year and depending on the timing of the customer payments, it can result in an immaterial amount of deferred revenue or a receivable from the customer. As of June 30, 2019, the Company estimates it had unsatisfied capacity performance obligations of $7.9 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,		Six months ended June 30,	
	2019	2018	2019	2018
Avista Utilities				
Revenue from contracts with customers	$ 231,605	$ 239,113	$ 585,907	$ 593,275
Derivative revenues	42,128	56,357	66,255	114,749
Alternative revenue programs	9,725	3,570	5,067	(2,369)
Deferrals and amortizations for rate refunds to customers	2,512	982	4,647	(18,840)
Other utility revenues	3,838	2,200	5,634	4,161
Total Avista Utilities	289,808	302,222	667,510	690,976
AEL&P				
Revenue from contracts with customers	8,620	10,759	19,356	25,409
Deferrals and amortizations for rate refunds to customers	(47)	(427)	(95)	(1,549)
Other utility revenues	170	150	363	285
Total AEL&P	8,743	10,482	19,624	24,145
Other				
Revenue from contracts with customers	2,024	6,324	9,671	13,053
Other revenues	237	270	488	485
Total other	2,261	6,594	10,159	13,538
Total operating revenues	$ 300,812	$ 319,298	$ 697,293	$ 728,659

Utility Revenue from Contracts with Customers by Type and Service

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

	2019			2018		
	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	$ 72,886	$ 3,724	$ 76,610	$ 74,818	$ 4,155	$ 78,973
Commercial and governmental	76,375	4,837	81,212	76,462	6,541	83,003
Industrial	26,245	—	26,245	27,985	—	27,985
Public street and highway lighting	1,897	59	1,956	1,899	63	1,962
Total retail revenue	177,403	8,620	186,023	181,164	10,759	191,923
Transmission	4,250	—	4,250	4,171	—	4,171
Other revenue from contracts with customers	4,379	—	4,379	3,919	—	3,919
Total revenue from contracts with customers	$ 186,032	$ 8,620	$ 194,652	$ 189,254	$ 10,759	$ 200,013
NATURAL GAS OPERATIONS						
Revenue from contracts with customers						
Residential	$ 27,937	$ —	$ 27,937	$ 30,767	$ —	$ 30,767
Commercial	13,369	—	13,369	14,668	—	14,668
Industrial and interruptible	1,103	—	1,103	1,078	—	1,078
Total retail revenue	42,409	—	42,409	46,513	—	46,513
Transportation	2,039	—	2,039	2,221	—	2,221
Other revenue from contracts with customers	1,125	—	1,125	1,125	—	1,125
Total revenue from contracts with customers	$ 45,573	$ —	$ 45,573	$ 49,859	$ —	$ 49,859
Six months ended June 30:						
ELECTRIC OPERATIONS						
Residential	$ 188,279	$ 9,576	$ 197,855	$ 189,571	$ 10,693	$ 200,264
Commercial and governmental	155,621	9,658	165,279	155,371	14,585	169,956
Industrial	51,493	—	51,493	53,104	—	53,104
Public street and highway lighting	3,800	122	3,922	3,758	131	3,889
Total retail revenue	399,193	19,356	418,549	401,804	25,409	427,213
Transmission	9,402	—	9,402	8,001	—	8,001
Other revenue from contracts with customers	12,573	—	12,573	10,210	—	10,210
Total electric revenue from contracts with customers	$ 421,168	$ 19,356	$ 440,524	$ 420,015	$ 25,409	$ 445,424

	2019			2018		
	Avista Utilities	AEL&P	Total Utility	Avista Utilities	AEL&P	Total Utility
NATURAL GAS OPERATIONS						
Residential	$ 105,272	$ —	$ 105,272	$ 111,421	$ —	$ 111,421
Commercial	49,964	—	49,964	52,040	—	52,040
Industrial and interruptible	2,730	—	2,730	2,761	—	2,761
Total retail revenue	157,966	—	157,966	166,222	—	166,222
Transportation	4,523	—	4,523	4,788	—	4,788
Other revenue from contracts with customers	2,250	—	2,250	2,250	—	2,250
Total natural gas revenue from contracts with customers	$ 164,739	$ —	$ 164,739	$ 173,260	$ —	$ 173,260

NOTE 5. LEASES

ASC 842, which outlines a model for entities to use in accounting for leases and supersedes previous lease accounting guidance, became effective on January 1, 2019. The core principle of the model is that an entity should recognize the ROU assets and liabilities that arise from leases on the balance sheet and depreciate or amortize the asset and liability over the term of the lease, as well as provide disclosure to enable users of the condensed consolidated financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases.

Significant Judgments and Assumptions

The Company determines if an arrangement is a lease, as well as its classification, at its inception.

ROU assets represent the Company's right to use an underlying asset for the lease term, and lease liabilities represent the Company's obligation to make lease payments arising from the lease. Operating and finance lease ROU assets and lease liabilities are recognized at the commencement date of the agreement based on the present value of lease payments over the lease term. As most of the Company's leases do not provide an implicit rate, the Company uses its incremental borrowing rate based on the information available at the commencement date to determine the present value of lease payments. The implicit rate is used when it is readily determinable. The operating and finance lease ROU assets also include any lease payments made and exclude lease incentives, if any, that accrue to the benefit of the lessee.

Lease terms may include options to extend or terminate the lease when it is reasonably certain that the Company will exercise that option. Lease expense for lease payments is recognized on a straight-line basis over the lease term. Any difference between lease expense and cash paid for leased assets is recognized as a regulatory asset or regulatory liability.

Description of Leases

The Company has operating leases for land associated with its utility operations, as well as communication sites which support network and radio communications within its service territory. The Company's leases have remaining terms of 1 to 74 years. Most of the Company's leases include options to extend the lease term for periods of 5 to 50 years. Options are exercised at the Company's discretion.

The Company has an operating lease with the state of Montana associated with submerged land around the Company's hydroelectric facilities in the Clark Fork River basin, which expires in 2046. The terms of this lease are subject to renegotiation, depending on the outcome of ongoing litigation between Montana and NorthWestern Energy. In addition, the state of Montana and Avista Corp. are engaged in litigation regarding the lease terms. As such, amounts recorded for this lease are uncertain and amounts may change in the future depending on the outcome of the ongoing litigation.

Through its wholly-owned subsidiary, AEL&P, the Company has a PPA which is treated as a finance lease for accounting purposes related to the Snettisham Hydroelectric Project, which expires in 2034. For ratemaking purposes, this lease is treated as an operating lease with a constant level of annual rental expense (straight line rent expense). Because of this regulatory treatment, any difference between the operating lease expense for ratemaking purposes and the expenses recognized under finance lease treatment (interest and amortization of the finance lease ROU asset) is recorded as a regulatory asset and amortized during the later years of the lease when the finance lease expense is less than the operating lease expense included in base rates. In 2018 and prior years, the total cost associated with the Snettisham PPA was included in resource costs. Due to the adoption of the new lease standard, the amortization of the ROU asset is now included in depreciation and amortization and the interest associated with the lease liability is now included in interest expense on the Condensed Consolidated Statement of Income.

Certain of the Company's lease agreements include rental payments which are periodically adjusted over the term of the agreement based on the consumer price index. The Company's lease agreements do not include any material residual value guarantees or material restrictive covenants.

Avista Corp. does not record leases with a term of 12 months or less in the Condensed Consolidated Balance Sheet. Total short-term lease costs for the three and six months ended June 30, 2019 are immaterial.

Leases that Have Not Yet Commenced

In June 2018, the Company finalized a lease agreement for office space in Spokane, Washington. The lease period is expected to commence in April 2020, once construction of the building is complete. The lease is an operating lease for a term of 12 years and will result in annual rent expense of approximately $1.1 million, which will be reflected in other operating expenses. In addition to base rent expense, the Company is expected to share in a portion of the annual operating expenses of the building.

In March 2019, the Company signed a PPA with Clearway Energy Group (Clearway) to purchase all of the power generated from the Rattlesnake Flat Wind project in Adams County, Washington. The facility has a nameplate capacity of 144 MW and is expected to generate approximately 50 aMW. During negotiations with Clearway, Avista Corp. was involved in the selection of the preferred generation facility type. The PPA is a 20-year agreement with deliveries expected to begin in 2020. The PPA provides Avista Corp. with additional renewable energy, capacity and environmental attributes. Avista Corp. expects to recover the cost of the power purchased through its retail rates. This PPA is considered a lease under ASC 842; however, all of the payments are variable payments based on whether power is generated from the facility. Since all the payments are variable, the Company will not record a lease liability for the agreement, but the expense will be included in resource costs when it becomes operational in 2020.

The components of lease expense were as follows for the three and six months ended June 30, 2019 (dollars in thousands):

	Three months ended June 30, 2019	Six months ended June 30, 2019
Operating lease cost:		
Fixed lease cost (Other operating expenses)	$ 1,106	$ 2,209
Variable lease cost (Other operating expenses)	244	487
Total operating lease cost	$ 1,350	$ 2,696
Finance lease cost:		
Amortization of ROU asset (Depreciation and amortization)	$ 910	$ 1,820
Interest on lease liabilities (Interest expense)	699	1,398
Total finance lease cost	$ 1,609	$ 3,218

Supplemental cash flow information related to leases was as follows for the six months ended June 30 (dollars in thousands):

	2019
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash outflows:	
Operating lease payments	$ 4,197
Interest on finance lease	1,398
Total operating cash outflows	$ 5,595
Finance cash outflows:	
Principal payments on finance lease	$ 1,330

Supplemental balance sheet information related to leases was as follows for June 30, 2019 (dollars in thousands):

		June 30, 2019
Operating Leases		
Operating lease ROU assets (Other property and investments-net and other non-current assets)	$	70,442
Other current liabilities	$	4,123
Other non-current liabilities and deferred credits		68,228
Total operating lease liabilities	$	72,351
Finance Leases		
Finance lease ROU assets (Other property and investments-net and other non-current assets) (a)	$	52,800
Other current liabilities (b)	$	2,730
Other non-current liabilities and deferred credits (b)		53,150
Total finance lease liabilities	$	55,880
Weighted Average Remaining Lease Term		
Operating leases		27.01 years
Finance leases		8.39 years
Weighted Average Discount Rate		
Operating leases		3.82%
Finance leases		4.88%

(a) At December 31, 2018, the finance lease ROU assets were included in "Net utility property" on the Condensed Consolidated Balance Sheet. Due to the adoption of ASC 842 on January 1, 2019, the Company has reclassified these amounts to "Other property and investments-net and other non-current assets" on the Condensed Consolidated Balance Sheet such that their presentation as of June 30, 2019 is consistent with operating leases.

(b) At December 31, 2018, the finance lease liabilities were included in "Current portion of long-term debt" and "Long-term debt and capital leases" on the Condensed Consolidated Balance Sheet. Due to the adoption of ASC 842 on January 1, 2019, the Company has reclassified these amounts to "Other current liabilities" and "Other non-current liabilities and deferred credits" on the Condensed Consolidated Balance Sheet such that their presentation as of June 30, 2019 is consistent with operating leases.

Maturities of lease liabilities (including principal and interest) were as follows as of June 30, 2019 (dollars in thousands):

		Operating Leases		Finance Leases
Remainder 2019	$	4,170	$	2,726
2020		4,364		5,462
2021		4,367		5,457
2022		4,375		5,460
2023		4,391		5,456
Thereafter		95,939		54,574
Total lease payments	$	117,606	$	79,135
Less: imputed interest		(45,255)		(23,255)
Total	$	72,351	$	55,880

Future minimum lease payments (including principal and interest) under Topic 840 as of December 31, 2018 (dollars in thousands):

	Operating Leases	Finance Leases
2019	$ 4,995	$ 5,455
2020	4,876	5,462
2021	4,859	5,457
2022	4,782	5,460
2023	4,780	5,456
Thereafter	102,389	54,574
Total lease payments	$ 126,681	$ 81,864
Less: imputed interest	—	(24,654)
Total	$ 126,681	$ 57,210

NOTE 6. 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, in order 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. On the basis of 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 four 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 helps mitigate 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, 2019 that are 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 2019	1	559	5,378	61,385	82	1,330	481	26,150
2020	—	—	1,138	60,253	123	1,055	1,430	23,683
2021	—	—	—	17,640	—	246	1,049	8,575
2022	—	—	—	1,350	—	—	—	—
2023	—	—	—	—	—	—	—	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents the underlying energy commodity derivative volumes as of December 31, 2018 that are 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
2019	206	941	10,732	101,293	197	2,790	2,909	54,418
2020	—	—	1,138	47,225	123	959	1,430	14,625
2021	—	—	—	9,670	—	—	1,049	4,100
2022	—	—	—	—	—	—	—	—
2023	—	—	—	—	—	—	—	—
Thereafter	—	—	—	—	—	—	—	—

(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 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 collected 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 and 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 that Avista Corp. has outstanding as of June 30, 2019 and December 31, 2018 (dollars in thousands):

	June 30, 2019	December 31, 2018
Number of contracts	27	31
Notional amount (in United States dollars)	$ 2,780	$ 4,018
Notional amount (in Canadian dollars)	3,680	5,386

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. hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swap derivatives and U.S. Treasury lock agreements. These interest rate swap derivatives and U.S. Treasury lock agreements 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 that Avista Corp. has outstanding as of June 30, 2019 and December 31, 2018 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
June 30, 2019	6	$ 70,000	2019
	6	60,000	2020
	3	35,000	2021
	9	100,000	2022
December 31, 2018	6	$ 70,000	2019
	6	60,000	2020
	2	25,000	2021
	7	80,000	2022

Upon settlement of interest rate swap derivatives, the cash payments made or received are recorded as a regulatory asset or liability and are subsequently amortized as a component of interest expense over the life of the associated debt. The settled interest rate swap derivatives are also included as a part of Avista Corp.'s cost of debt calculation for ratemaking purposes.

The fair value of outstanding interest rate swap derivatives can vary significantly from period to period depending on the total notional amount of swap derivatives outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. Avista Corp. is required to make cash payments to settle the interest rate swap derivatives when the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, Avista Corp. receives cash to settle its interest rate swap derivatives when prevailing market rates at the time of settlement exceed the fixed swap rates.

Summary of Outstanding Derivative Instruments

The amounts recorded on the Condensed Consolidated Balance Sheet as of June 30, 2019 and December 31, 2018 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, 2019 (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	$ 33	$ —	$ —	$ 33
Interest rate swap derivatives				
Other current assets	771	(338)	—	433
Other current liabilities	—	(4,771)	—	(4,771)
Other non-current liabilities and deferred credits	631	(27,309)	5,030	(21,648)
Energy commodity derivatives				
Other current assets	582	(247)	—	335
Other current liabilities	26,541	(52,004)	20,960	(4,503)
Other non-current liabilities and deferred credits	3,996	(14,760)	5,214	(5,550)
Total derivative instruments recorded on the balance sheet	$ 32,554	$ (99,429)	$ 31,204	$ (35,671)

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of December 31, 2018 (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 liabilities	$ —	$ (45)	$ —	$ (45)
Interest rate swap derivatives				
Other current assets	5,283	—	—	5,283
Other property and investments-net and other non-current assets	5,283	(440)	—	4,843
Other non-current liabilities and deferred credits	—	(7,391)	530	(6,861)
Energy commodity derivatives				
Other current assets	400	(130)	—	270
Other current liabilities	31,457	(73,155)	37,790	(3,908)
Other non-current liabilities and deferred credits	4,426	(21,292)	13,427	(3,439)
Total derivative instruments recorded on the balance sheet	$ 46,849	$ (102,453)	$ 51,747	$ (3,857)

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 a downgrade in Avista Corp.'s credit ratings or changes in market prices, 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 Avista Corp.'s collateral outstanding related to its derivative instruments as of June 30, 2019 and December 31, 2018 (in thousands):

	June 30, 2019	December 31, 2018
Energy commodity derivatives		
Cash collateral posted	$ 26,174	$ 78,025
Letters of credit outstanding	14,600	6,500
Balance sheet offsetting (cash collateral against net derivative positions)	26,174	51,217
Interest rate swap derivatives		
Cash collateral posted	5,030	530
Balance sheet offsetting (cash collateral against net derivative positions)	5,030	530

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 that are in a liability position and the amount of additional collateral Avista Corp. could be required to post as of June 30, 2019 and December 31, 2018 (in thousands):

	June 30, 2019	December 31, 2018
Energy commodity derivatives		
Liabilities with credit-risk-related contingent features	$ 1,564	$ 2,193
Additional collateral to post	1,563	2,193
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	32,418	7,831
Additional collateral to post	25,986	6,579

NOTE 7. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

Avista Utilities

Avista Utilities' maintained the same pension and other postretirement plans during the six months ended June 30, 2019 as those described as of December 31, 2018. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $14.6 million in cash to the pension plan for the six months ended June 30, 2019 and it expects to contribute a total of $22.0 million in 2019.

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	
	2019	2018	2019	2018
Three months ended June 30:				
Service cost (a)	$ 4,948	$ 5,450	$ 753	$ 804
Interest cost	7,100	6,466	1,164	1,197
Expected return on plan assets	(7,953)	(8,250)	(611)	(500)
Amortization of prior service cost	75	75	(275)	209
Net loss recognition	2,426	1,842	1,329	562
Net periodic benefit cost	$ 6,596	$ 5,583	$ 2,360	$ 2,272
Six months ended June 30:				
Service cost (a)	$ 9,822	$ 10,900	$ 1,525	$ 1,608
Interest cost	14,238	12,932	2,536	2,394
Expected return on plan assets	(15,768)	(16,500)	(1,329)	(1,000)
Amortization of prior service cost	150	150	(550)	(606)
Net loss recognition	4,841	3,930	2,575	2,217
Net periodic benefit cost	$ 13,283	$ 11,412	$ 4,757	$ 4,613

(a) 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.

NOTE 8. INCOME TAXES

The following table summarizes the significant factors impacting the difference between our 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,			
	2019		2018		2019		2018	
Federal income taxes at statutory rates	$ 4,874	21.0 %	$ 6,479	21.0 %	$ 35,513	21.0 %	$ 20,269	21.0 %
Increase (decrease) in tax resulting from:								
Tax effect of regulatory treatment of utility plant differences	(2,139)	(9.2)	(1,981)	(6.4)	(4,219)	(2.5)	(2,999)	(3.1)
State income tax expense	(8)	—	60	0.2	1,651	1.0	1,024	1.1
Acquisition costs	112	0.5	73	0.2	(1,712)	(1.0)	119	0.1
Non-plant excess deferred turnaround (1)	(5,091)	(21.9)	(11)	—	(5,601)	(3.3)	(11)	—
Tax loss on sale of METALfx	(1,259)	(5.4)	—	—	(1,259)	(0.8)	—	—
Valuation allowance	1,245	5.3	—	—	1,245	0.7	—	—
Settlement of equity awards	—	—	—	—	612	0.4	(990)	(1.0)
Other	525	2.2	589	1.9	2,046	1.2	(1,493)	(1.6)
Total income tax expense (benefit)	$ (1,741)	(7.5)%	$ 5,209	16.9 %	$ 28,276	16.7 %	$ 15,919	16.5 %

(1) In March 2019, the IPUC approved an all-party settlement agreement related to electric tax benefits that were set aside for Colstrip in the 2017 general rate case order. In the approved settlement agreement, the parties agreed to utilize approximately $6.4 million ($5.1 million when tax-effected) of the electric tax benefits to offset costs associated with accelerating the depreciation of Colstrip Units 3 & 4, to reflect a remaining useful life of those units through December 31, 2027. In the second quarter 2019, the Company recorded a one-time charge to depreciation expense with an offsetting amount included in income tax expense.

NOTE 9. COMMITTED LINES OF CREDIT

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million that expires in April 2021. The committed line of credit is secured by non-transferable first mortgage bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under the Company's revolving committed line of credit were as follows as of June 30, 2019 and December 31, 2018 (dollars in thousands):

	June 30, 2019	December 31, 2018
Balance outstanding at end of period (1)	$ 169,000	$ 190,000
Letters of credit outstanding at end of period	$ 18,603	$ 10,503
Average interest rate at end of period	3.26%	3.18%

(1) As of June 30, 2019 and December 31, 2018, the balance outstanding was classified as short-term borrowings on the Condensed Consolidated Balance Sheet.

AEL&P

AEL&P has a committed line of credit in the amount of $25.0 million that expires in November 2019. As of June 30, 2019 and December 31, 2018, there were no borrowings or letters of credit outstanding under this committed line of credit. 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.

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 with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly.

The distribution rates paid were as follows during the six months ended June 30, 2019 and the year ended December 31, 2018:

	June 30, 2019	December 31, 2018
Low distribution rate	3.40%	2.36%
High distribution rate	3.50%	3.61%
Distribution rate at the end of the period	3.40%	3.61%

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 that 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 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 are reasonable estimates of their fair values. Long-term debt (including current portion and material capital leases) and long-term debt to affiliated trusts are reported at carrying value on the Condensed Consolidated Balance Sheets.

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 measurement) and the lowest priority to fair values derived from unobservable inputs (Level 3 measurement).

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 those financial instruments that are 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 that are 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 that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also 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, 2019 and December 31, 2018 (dollars in thousands):

	June 30, 2019		December 31, 2018	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 1,053,500	$ 1,198,009	$ 1,053,500	$ 1,142,292
Long-term debt (Level 3)	767,000	762,204	767,000	734,742
Snettisham finance lease obligation (Level 3)	55,880	58,200	57,210	55,600
Long-term debt to affiliated trusts (Level 3)	51,547	39,691	51,547	38,145

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 par values of 77.00 to 130.25, where a par value of 100.0 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 capital lease obligation, the estimated fair value of these items was determined based on a discounted cash flow model using available market information. The Snettisham capital lease obligation was discounted to present value using the Morgan Markets A Ex-Fin discount rate as published on June 30, 2019.

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, 2019 and December 31, 2018 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, 2019					
Assets:					
Energy commodity derivatives	$ —	$ 31,074	$ —	$ (30,739)	$ 335
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	45	(45)	—
Foreign currency exchange derivatives	—	33	—	—	33
Interest rate swap derivatives	—	1,402	—	(969)	433
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities (2)	1,787	—	—	—	1,787
Equity securities (2)	6,325	—	—	—	6,325
Total	$ 8,112	$ 32,509	$ 45	$ (31,753)	$ 8,913
Liabilities:					
Energy commodity derivatives	$ —	$ 63,974	$ —	$ (56,913)	$ 7,061
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	3,037	(45)	2,992
Interest rate swap derivatives	—	32,418	—	(5,999)	26,419
Total	$ —	$ 96,392	$ 3,037	$ (62,957)	$ 36,472

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2018					
Assets:					
Energy commodity derivatives	$ —	$ 36,252	$ —	$ (35,982)	$ 270
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	31	(31)	—
Interest rate swap derivatives	—	10,566	—	(440)	10,126
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities (2)	1,745	—	—	—	1,745
Equity securities (2)	6,157	—	—	—	6,157
Total	$ 7,902	$ 46,818	$ 31	$ (36,453)	$ 18,298
Liabilities:					
Energy commodity derivatives	$ —	$ 89,283	$ —	$ (87,199)	$ 2,084
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	2,805	(31)	2,774
Power exchange agreement	—	—	2,488	—	2,488
Power option agreement	—	—	1	—	1
Foreign currency exchange derivatives	—	45	—	—	45
Interest rate swap derivatives	—	7,831	—	(970)	6,861
Total	$ —	$ 97,159	$ 5,294	$ (88,200)	$ 14,253

(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) These assets are 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 6 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. In particular, 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.

To establish fair value for foreign currency derivatives, the Company uses forward market curves for Canadian dollars against the US dollar and multiplies the difference between the locked-in price and the market price by the notional amount of the derivative. Forward foreign currency market curves are provided by third party brokers. The Company's credit spread is factored into the locked-in price of the foreign exchange contracts.

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. The balance disclosed in the table above excludes cash and cash equivalents of $0.4 million as of June 30, 2019 and $0.5 million as of December 31, 2018.

Level 3 Fair Value

Under the power exchange agreement, which expired on June 30, 2019, the Company purchased power at a price that was based on the average operating and maintenance (O&M) charges from three surrogate nuclear power plants around the country. To estimate the fair value of this agreement, the Company estimated the difference between the purchase price based on the future O&M charges and forward prices for energy. The Company compared the Level 2 brokered quotes and forward price curves described above to an internally developed forward price which was based on the average O&M charges from the three surrogate nuclear power plants for the current year. The Company estimated the volumes of the transactions that would take place in the future based on historical average transaction volumes per delivery year (November to April). Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement.

For the natural gas commodity exchange agreement, the Company uses the same Level 2 brokered 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 have not been 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, 2019 (dollars in thousands):

	Fair Value (Net) at June 30, 2019	Valuation Technique	Unobservable Input	Range
Natural gas exchange agreement	$ (2,992)	Internally derived weighted average cost of gas	Forward purchase prices	$1.37 - $2.30/mmBTU
			Forward sales prices	$1.45 - $3.62/mmBTU
			Purchase volumes	118,162 - 310,000 mmBTUs
			Sales volumes	60,000 - 310,000 mmBTUs

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

The following table presents activity for energy commodity derivative assets (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	Power Exchange Agreement	Total
Three months ended June 30, 2019:			
Balance as of April 1, 2019	$ (2,104)	$ (612)	$ (2,716)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities (1)	(829)	1,454	625
Settlements	(59)	(842)	(901)
Ending balance as of June 30, 2019 (2)	$ (2,992)	$ —	$ (2,992)

	Natural Gas Exchange Agreement	Power Exchange Agreement	Total
Three months ended June 30, 2018:			
Balance as of April 1, 2018	$ (2,805)	$ (10,163)	$ (12,968)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities (1)	(768)	2,597	1,829
Settlements	93	1,221	1,314
Ending balance as of June 30, 2018 (2)	$ (3,480)	$ (6,345)	$ (9,825)
Six months ended June 30, 2019:			
Balance as of January 1, 2019	$ (2,774)	$ (2,488)	$ (5,262)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities (1)	8,148	436	8,584
Settlements	(8,366)	2,052	(6,314)
Ending balance as of June 30, 2019 (2)	$ (2,992)	$ —	$ (2,992)
Six months ended June 30, 2018:			
Balance as of January 1, 2018	$ (3,164)	$ (13,245)	$ (16,409)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities (1)	(565)	720	155
Settlements	249	6,180	6,429
Ending balance as of June 30, 2018 (2)	$ (3,480)	$ (6,345)	$ (9,825)

(1) All gains and losses are included in other regulatory assets and liabilities. There were no gains and losses included in either net income or other comprehensive income during any of the periods presented in the table above.
(2) There were no purchases, issuances or transfers from other categories of any derivatives instruments during the periods presented in the table above.

NOTE 12. COMMON STOCK

The Company has entered into four separate sales agency agreements under which the sales agents may offer and sell new shares of the Company's common stock from time to time. During the three and six months ended June 30, 2019 the Company issued 0.4 million shares under the sales agency agreements. These agreements provide for the offering of a maximum of approximately 4.6 million shares, of which approximately 4.2 million remain unissued as of June 30, 2019. Subject to the satisfaction of customary conditions, the Company has the right to increase the maximum number of shares that may be offered under these agreements subject to regulatory approval.

NOTE 13. ACCUMULATED OTHER COMPREHENSIVE LOSS

Accumulated other comprehensive loss, net of tax, consisted of the following as of June 30, 2019 and December 31, 2018 (dollars in thousands):

	June 30, 2019	December 31, 2018
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $2,006 and $2,091, respectively	$ 7,545	$ 7,866

The following table details the reclassifications out of accumulated other comprehensive loss to net income 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	2019	2018	2019	2018	Affected Line Item in Statement of Income
Amortization of defined benefit pension items					
Amortization of net prior service cost	$ (200)	$ (228)	$ (400)	$ (456)	(a)
Amortization of net loss	3,755	2,995	7,416	5,990	(a)
Adjustment due to effects of regulation	(3,352)	(2,509)	(6,610)	(5,017)	(a)
	203	258	406	517	Total before tax
	(42)	(54)	(85)	(109)	Tax expense
	$ 161	$ 204	$ 321	$ 408	Net of tax

(a) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 7 for additional details).

NOTE 14. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORP. SHAREHOLDERS

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corp. shareholders 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,	
	2019	2018	2019	2018
Numerator:				
Net income attributable to Avista Corp. shareholders	$ 25,319	$ 25,577	$ 141,113	$ 80,467
Denominator:				
Weighted-average number of common shares outstanding-basic	65,894	65,677	65,814	65,658
Effect of dilutive securities:				
Performance and restricted stock awards	69	306	69	299
Weighted-average number of common shares outstanding-diluted	65,963	65,983	65,883	65,957
Earnings per common share attributable to Avista Corp. shareholders:				
Basic	$ 0.38	$ 0.39	$ 2.14	$ 1.23
Diluted	$ 0.38	$ 0.39	$ 2.14	$ 1.22

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 intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista Utilities' or AEL&P's operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels (referred to as "Total Dissolved Gas" or "TDG") in the Clark Fork River exceed state of Idaho and federal water quality numeric standards downstream of Cabinet Gorge particularly during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement (CFSA) as incorporated in Avista Corp.'s FERC license for the Clark Fork Project, Avista Corp. has worked in consultation with agencies, tribes and other stakeholders to address this issue. Under the terms of a gas supersaturation mitigation plan, Avista Corp. is reducing TDG by constructing spill crest modifications on spill gates at the dam. These modifications have been shown to be effective in reducing

TDG downstream. TDG monitoring and analysis is ongoing. Under the terms of the mitigation plan, Avista Corp. will continue to work with stakeholders to determine the degree to which TDG abatement reduces future mitigation obligations. The Company has sought, and will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Legal Proceedings Related to the Terminated Acquisition by Hydro One

See Note 17 for information regarding the termination of the proposed acquisition of the Company by Hydro One.

In connection with the now terminated acquisition, three lawsuits were filed in the United States District Court for the Eastern District of Washington and were subsequently voluntarily dismissed by the plaintiffs.

One lawsuit was filed in the Superior Court for the State of Washington in and for Spokane County, captioned as follows:

- *Fink v. Morris, et al.,* No. 17203616-6 (filed September 15, 2017, amended complaint filed October 25, 2017).

The complaint generally alleged that the members of the Board of Directors of Avista Corp. breached their fiduciary duties by, among other things, conducting an allegedly inadequate sale process and agreeing to the acquisition at a price that allegedly undervalued Avista Corporation, and that Hydro One Limited, Olympus Holding Corp., and Olympus Corp. aided and abetted those purported breaches of duty. The complaint sought various remedies, including monetary damages, attorneys' fees and expenses. Subsequent to the termination of the proposed acquisition in January 2019, the complaint was voluntarily dismissed by the plaintiffs.

2015 Washington General Rate Cases

In January 2016, the Company received an order (Order 05) that concluded its electric and natural gas general rate cases that were originally filed with the WUTC in February 2015. New electric and natural gas rates were effective on January 11, 2016.

WUTC Order Denying Industrial Customers of Northwest Utilities / Public Counsel Joint Motion for Clarification, WUTC Staff Motion to Reconsider and WUTC Staff Motion to Reopen Record

In January 2016, the Industrial Customers of Northwest Utilities, the Public Counsel Unit of the Washington State Office of the Attorney General (PC) and the WUTC Staff, which is a separate party in the general rate case proceedings from the WUTC Advisory Staff, filed Motions for Clarification requesting the WUTC to clarify their attrition adjustment and the end result electric revenue amounts. The Motions for Clarification suggested that the electric revenue decrease should have been significantly larger than what was included in Order 05.

In February 2016, the WUTC issued an order (Order 06) denying the Motions summarized above and affirming Order 05, including an $8.1 million decrease in electric base revenue.

PC Petition for Judicial Review

In March 2016, PC filed in Thurston County Superior Court a Petition for Judicial Review of the WUTC's Order 05 and Order 06 described above. In April 2016, this matter was certified for review directly by the Court of Appeals, an intermediate appellate court in the State of Washington.

On August 7, 2018, the Court of Appeals issued a "Published Opinion" (Opinion) which concluded that the WUTC's use of an attrition allowance to calculate Avista Corp.'s rate base violated Washington law. In the Opinion, the Court stated that because the projected additions to rate base in the future were not "used and useful" for service at the time the request for the rate increase was made, they may not lawfully be included in the Company's rate base to justify a rate increase. Accordingly, the Court concluded that the WUTC erred in including an attrition allowance in the calculation of Avista Corp.'s electric and natural gas rate base. The Court noted, however, that the law does not prohibit an attrition allowance in the calculation, for ratemaking purposes, of recoverable operating and maintenance expense. Since the WUTC order provided one lump sum attrition allowance without distinguishing what portion was for rate base and which was for operating and maintenance expenses or other considerations, the Court struck all portions of the attrition allowance attributable to Avista Corp.'s rate base and reversed and remanded the case for the WUTC to recalculate Avista Corp.'s rates without including an attrition allowance in the calculation of rate base. On October 1, 2018, the Court of Appeals terminated its review of this case, remanding it back to the Thurston County Superior Court. On April 17, 2019, the Thurston County Superior Court issued a Remand Order, granting a Joint Motion of Avista Corp., PC and the WUTC to remand the case back to the WUTC.

On June 20, 2019, Avista Corp. filed testimony with the WUTC in the remand case. In Avista Corp.'s testimony, it asserted that the potential amount to return to customers is limited to the 2015 general rate cases because in subsequent Washington general rate cases (specifically those approved in December 2016), the WUTC did not include any attrition allowance on rate base. In the remand testimony the Company also asserted that no refund is due to customers for the 2015 general rate cases because actual 2016 electric rate base was greater than the 2016 electric rate base allowed in the general rate case, which included an attrition allowance. In addition, while 2016 actual natural gas rate base was slightly lower than the rate base allowed in the general rate case including the attrition allowance, any over-earnings were offset by the earnings sharing mechanism that allowed for a refund to customers.

Even though the Company believes the issue only relates to the 2015 general rate cases and no refund is due to customers, the Company cannot predict the outcome of this matter at this time and cannot estimate how much, if any, it could be required to refund to customers.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that 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 that 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 20 of the Notes to Consolidated Financial Statements" in the 2018 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) attributable to Avista Corp. shareholders. 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 that are 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 any 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, 2019:						
Operating revenues	$ 289,808	$ 8,743	$ 298,551	$ 2,261	$ —	$ 300,812
Resource costs	88,506	(67)	88,439	—	—	88,439
Other operating expenses (2)	84,602	3,129	87,731	6,332	—	94,063
Depreciation and amortization	53,070	2,409	55,479	155	—	55,634
Income (loss) from operations	40,978	3,016	43,994	(4,226)	—	39,768
Interest expense (3)	24,316	1,595	25,911	148	(197)	25,862
Income taxes	(2,947)	380	(2,567)	826	—	(1,741)
Net income attributable to Avista Corp. shareholders	21,219	1,076	22,295	3,024	—	25,319
Capital expenditures (4)	103,297	3,076	106,373	22	—	106,395
For the three months ended June 30, 2018:						
Operating revenues	$ 302,222	$ 10,482	$ 312,704	$ 6,594	$ —	$ 319,298
Resource costs	103,022	2,947	105,969	—	—	105,969
Other operating expenses (2) (5)	78,848	3,213	82,061	6,543	—	88,604
Depreciation and amortization	44,186	1,465	45,651	199	—	45,850
Income (loss) from operations (5)	50,848	2,579	53,427	(148)	—	53,279
Interest expense (3)	24,428	896	25,324	382	(234)	25,472
Income taxes	4,735	446	5,181	28	—	5,209
Net income attributable to Avista Corp. shareholders	24,252	1,282	25,534	43	—	25,577
Capital expenditures (4)	97,963	3,352	101,315	338	—	101,653

Table of Contents

		Avista Utilities		Alaska Electric Light and Power Company		Total Utility		Other		Intersegment Eliminations (1)		Total
For the six months ended June 30, 2019:												
Operating revenues	$	667,510	$	19,624	$	687,134	$	10,159	$	—	$	697,293
Resource costs		227,218		(1,432)		225,786		—		—		225,786
Other operating expenses (2)		185,185		6,188		191,373		13,687		—		205,060
Depreciation and amortization		99,577		4,816		104,393		364		—		104,757
Income (loss) from operations		101,202		9,529		110,731		(3,892)		—		106,839
Interest expense (3)		48,580		3,191		51,771		736		(637)		51,870
Income taxes		25,597		1,743		27,340		936		—		28,276
Net income attributable to Avista Corp. shareholders		133,120		4,628		137,748		3,365		—		141,113
Capital expenditures (4)		195,606		4,382		199,988		184		—		200,172
For the six months ended June 30, 2018:												
Operating revenues	$	690,976	$	24,145	$	715,121	$	13,538	$	—	$	728,659
Resource costs		254,687		5,900		260,587		—		—		260,587
Other operating expenses (2)		153,987		6,044		160,031		13,367		—		173,398
Depreciation and amortization		87,453		2,931		90,384		380		—		90,764
Income (loss) from operations		138,993		8,701		147,694		(209)		—		147,485
Interest expense (3)		48,393		1,790		50,183		717		(399)		50,501
Income taxes		15,152		1,910		17,062		(1,143)		—		15,919
Net income (loss) attributable to Avista Corp. shareholders		79,792		5,054		84,846		(4,379)		—		80,467
Capital expenditures (4)		179,139		3,993		183,132		552		—		183,684
Total Assets:												
As of June 30, 2019:	$	5,520,529	$	277,934	$	5,798,463	$	107,753	$	(28,288)	$	5,877,928
As of December 31, 2018:	$	5,458,104	$	272,950	$	5,731,054	$	87,050	$	(35,528)	$	5,782,576

(1) Intersegment eliminations reported as interest expense represent intercompany interest.
(2) Other operating expenses for Avista Utilities for the three and six months ended June 30, 2019 and 2018 include merger transaction costs which are separately disclosed on the Condensed Consolidated Statements of Income.
(3) Including interest expense to affiliated trusts.
(4) The capital expenditures for the other businesses are included in other investing activities on the Condensed Consolidated Statements of Cash Flows.

NOTE 17. TERMINATION OF PROPOSED ACQUISITION BY HYDRO ONE

On July 19, 2017, Avista Corp. entered into a Merger Agreement that provided for Avista Corp. to become an indirect, wholly-owned subsidiary of Hydro One, subject to the satisfaction or waiver of specified closing conditions, including approval by regulatory agencies. Hydro One, based in Toronto, is Ontario’s largest electricity transmission and distribution provider.

Termination of the Merger Agreement

Due to the denial of the proposed merger by certain of the Company's regulatory commissions, on January 23, 2019, Avista Corp., Hydro One and certain subsidiaries thereof, entered into a Termination Agreement indicating their mutual agreement to terminate the Merger Agreement, effective immediately. Pursuant to the terms of the Termination Agreement, Hydro One paid Avista Corp. a $103 million termination fee on January 24, 2019. The termination fee was used for reimbursing the Company's transaction costs incurred from 2017 to 2019. The balance of the termination fee remaining after payment of 2019 transaction costs and applicable income taxes was used for general corporate purposes and reduced the Company's need for external financing. The 2019 costs totaled $19.7 million pre-tax and included financial advisers' fees, legal fees, consulting fees and employee time.

Other Information Related to the Terminated Acquisition

Due to the termination of the acquisition, all the financial commitments that were included in the various settlement agreements with the commissions for the proposed acquisition will not be required to be performed or observed.

The Company incurred significant transaction costs consisting primarily of consulting, banking fees, legal fees and employee time, and these costs are not being passed through to customers. When the Company was assuming the transaction was going to be completed, a significant portion of these costs were not deductible for income tax purposes. Now that the transaction has been terminated, the Company expects more of the previously incurred transaction costs to be deductible so it expects additional tax benefits from these costs in 2019.

See Note 15 for discussion of shareholder lawsuits filed against the Company, the Company's directors, Hydro One, Olympus Holding Corp., and Olympus Corp. in relation to the Merger Agreement and the proposed acquisition.

NOTE 18. SALE OF METALfx

In April 2019, Bay Area Manufacturing, Inc., a non-regulated subsidiary of Avista Corp., entered into a definitive agreement to sell its interest in METALfx to an independent third party. The transaction was a stock sale for a total cash purchase price of $17.5 million plus cash on-hand, subject to customary closing adjustments. The transaction closed on April 18, 2019, and as of that date the Company has no further involvement with METALfx.

The purchase price of $17.5 million, as adjusted, was divided among the security holders of METALfx, including the minority shareholder, pro rata based on ownership (Avista Corp. owned 89.2 percent of the equity of METALfx). As required under the purchase agreement, $1.2 million (7 percent of the purchase price) will be held in escrow for 24 months from the closing of the transaction to satisfy certain indemnification obligations.

When all escrow amounts are released, the sales transaction is expected to provide cash proceeds to Avista Corp., net of payments to the minority holder, contractually obligated compensation payments and other transaction expenses, of $16.5 million and result in a net gain after-tax of $2.3 million. The Company expects to receive the full amount of its portion of the escrow accounts; therefore, the full amounts are included in the gain calculation. The gross gain is included in "Other income," the transaction expenses paid are included in "Non-utility Other operating expenses" and any taxes associated with the sale are included in "Income tax expense" on the Condensed Consolidated Statements of Income.

Prior to the completion of the sales transaction, METALfx was not a reportable business segment and was included in other in the business segment footnote at Note 16. This transaction does not meet the criteria for discontinued operations as it does not represent a strategic shift that will have a major effect on the Company's ongoing operations,

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of
Avista Corporation
Spokane, Washington

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, 2019, and the related condensed consolidated statements of income, comprehensive income and equity for the three-month and six-month periods ended June 30, 2019 and 2018 and the related cash flows for the six-month periods ended June 30, 2019 and 2018, 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, 2018, 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 19, 2019, 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, 2018, 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

Seattle, Washington
August 6, 2019

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 has been prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q. The interim Management's Discussion and Analysis of Financial Condition and Results of Operations does not contain the full detail or analysis which would be included in a full fiscal year Form 10-K; therefore, it should be read in conjunction with the Company's 2018 Form 10-K.

Business Segments

Our business segments have not changed during the six months ended June 30, 2019. See the 2018 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) attributable to Avista Corp. shareholders 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,	
	2019	2018	2019	2018
Avista Utilities	$ 21,219	$ 24,252	$ 133,120	$ 79,792
AEL&P	1,076	1,282	4,628	5,054
Other	3,024	43	3,365	(4,379)
Net income attributable to Avista Corp. shareholders	$ 25,319	$ 25,577	$ 141,113	$ 80,467

Executive Level Summary

Overall Results

Net income attributable to Avista Corp. shareholders was $25.3 million for the three months ended June 30, 2019, a slight decrease from $25.6 million for the three months ended June 30, 2018. Net income was $141.1 million for the six months ended June 30, 2019, compared to $80.5 million for the six months ended June 30, 2018. The results for both the three and six months ended June 30, 2019 reflect, among other things, the positive impact of non-recurring events, as discussed below.

The increase in net income for the year-to-date was due to an increase in net income at Avista Utilities and our other businesses, partially offset by a decrease in net income at AEL&P. For the second quarter, net income at Avista Utilities and AEL&P decreased, while net income at our other businesses increased.

For the year-to-date, Avista Utilities' net income increased due to the receipt of a $103 million termination fee from Hydro One (see "Note 17 of the Notes to Condensed Consolidated Financial Statements"), as well as the positive impact of general rate increases and customer growth. These increases were partially offset by final transaction costs for the Hydro One transaction, taxes associated with the termination fee, increased transmission and distribution operating and maintenance costs (other operating expenses), a $7 million donation commitment to the local community and increased depreciation and amortization. For the second quarter, Avista Utilities' net income decreased due to increased transmission and distribution operating and maintenance costs (other operating expenses), donation commitment costs and depreciation and amortization, partially offset by the positive impact of general rate increases and customer growth.

AEL&P net income decreased primarily due to an increase in other operating expenses and a decrease in operating revenues.

The increase in net income at our other businesses for the second quarter and year-to-date was primarily due to the sale of METALfx and increased earnings from equity investments. In addition, 2018 included an impairment of one of our investments and expenses associated with a renovation project.

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

General Rate Cases and Regulatory Lag

We expect to experience regulatory lag during the period 2019 through 2021 due to the delay in general rate case filings related to the terminated Hydro One transaction and our continued investment in utility infrastructure. In April, we filed general rates cases in Washington that are two-year rate plans. We filed an electric only general rate case in Idaho in June and we filed a natural gas general rate case in Oregon in March (with a settlement in Oregon reached in July 2019). We expect these cases to provide rate relief in early 2020 and begin reducing the regulatory lag that we have been experiencing. Going forward, we will continue to strive to reduce the regulatory timing lag and more closely align our earned returns with those authorized by 2022. This will require adequate and timely rate relief in our jurisdictions. See "Regulatory Matters" for additional discussion of the 2019 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 regards 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

2015 General Rate Cases

In January 2016 we received an order which was reaffirmed by the WUTC in February 2016 that concluded our electric and natural gas general rate cases originally filed with the WUTC in February 2015. New electric and natural gas rates were effective on January 11, 2016.

The WUTC-approved rates were designed to provide a 1.6 percent, or $8.1 million, decrease in electric base revenue and a 7.4 percent, or $10.8 million, increase in natural gas base revenue. The WUTC also approved an ROR of 7.29 percent, with a common equity ratio of 48.5 percent and a 9.5 percent ROE.

In March 2016, the Public Counsel Unit of the Washington State Office of the Attorney General filed in Thurston County Superior Court a Petition for Judicial Review of the WUTC's orders (described above) that concluded our 2015 electric and natural gas general rate cases. In April 2016, this matter was certified for review directly by the Court of Appeals, an intermediate appellate court in the State of Washington.

On August 7, 2018, the Court of Appeals issued an Opinion which concluded that the WUTC's use of an attrition allowance to calculate Avista Corp.'s rate base violated Washington law. The Court struck all portions of the attrition allowance attributable to Avista Corp.’s rate base and reversed and remanded the case for the WUTC to recalculate Avista Corp.’s rates without including an attrition allowance in the calculation of rate base. On April 17, 2019, the Thurston County Superior Court issued a Remand Order, granting a Joint Motion of Avista Corp., PC and the WUTC to remand the case back to the WUTC.

On June 20, 2019, Avista Corp. filed testimony with the WUTC in the remand case. In our testimony we asserted that the potential amount to return to customers is limited to the 2015 general rate cases and we also asserted that no refund is due to customers. Even though we believe no refund is due to customers, we cannot predict the outcome of this matter at this time. See "Note 15 of the Notes to Condensed Consolidated Financial Statements" for further discussion of this matter.

2017 General Rate Cases

On April 26, 2018, the WUTC issued a final order in our electric and natural gas general rate cases that were originally filed on May 26, 2017. In the order, the WUTC approved new electric rates, effective on May 1, 2018, that increased base rates by 2.2 percent (designed to increase electric revenues by $10.8 million). The net increase in electric base rates was made up of an increase in our base revenue requirement of $23.2 million, an increase of $14.5 million in power supply costs and a decrease of $26.9 million for the impacts of the TCJA, which reflects the federal income tax rate change from 35 percent to 21 percent and the amortization of the regulatory liability for plant excess deferred income taxes that was recorded as of December 31, 2017.

While the WUTC authorized an increase in the ERM baseline to reflect increased power supply costs, it directed the parties to examine the functionality and rationale of the Company's power cost modeling and adjust the baseline only in extraordinary circumstances if necessary to more closely match the baseline to actual conditions.

For natural gas, the WUTC approved new natural gas base rates, effective on May 1, 2018, that decreased base rates by 2.4 percent (designed to decrease natural gas revenues by $2.1 million). The net decrease in natural gas base rates was made up of an increase in base revenues of $3.4 million that was offset by a decrease of $5.5 million for the impacts from the TCJA, which reflects the federal income tax rate change and the amortization of the regulatory liability for plant-related excess deferred income taxes that was recorded as of December 31, 2017.

In addition to the above, the WUTC also ordered, effective June 1, 2018, a one-year temporary reduction of $7.9 million in our revenue requirements for electric and $3.2 million for natural gas, reflecting reductions for the return of tax benefits associated with the non-plant excess deferred income taxes and the customer refund liability that was established in 2018 related to the change in federal income tax expense for the period January 1, 2018 to April 30, 2018.

The new rates are based on a ROR of 7.50 percent with a common equity ratio of 48.5 percent and a 9.5 percent ROE.

In our original filings, we requested three-year rate plans for electric and natural gas; however, in the final order the WUTC only provided for new rates effective on May 1, 2018.

TCJA Proceedings

In February 2019, we filed an all-party settlement agreement with the WUTC related to the electric tax benefits associated with the TCJA that were set aside for Colstrip in the 2017 general rate case order (effective May 1, 2018). In the settlement agreement, the parties agreed to utilize $10.9 million of the electric tax benefits to offset costs associated with accelerating the depreciation of Colstrip Units 3 & 4, to reflect a remaining useful life of those units through December 31, 2027. That portion of the settlement agreement was denied. The WUTC has indicated that it will review the TCJA and Colstrip in our next general rate case (which was filed on April 30, 2019).

2019 General Rate Cases

On April 30, 2019, we filed electric and natural gas general rate cases with the WUTC that are two-year rate plans. We have requested the following electric and natural gas base rate changes each year, which are designed to result in the following increases in annual revenues (dollars in millions):

	Electric		Natural Gas	
Effective Date	Revenue Increase	Base Rate Increase	Revenue Increase	Base Rate Increase
April 1, 2020	$ 45.8	9.1%	$ 12.9	13.8%
April 1, 2021	$ 18.9	3.5%	$ 6.5	6.1%

Our requests are based on a proposed ROR of 7.52 percent with a common equity ratio of 50 percent and a 9.9 percent ROE. The WUTC has up to 11 months to review our request and issue a decision.

Under these rate plans, we would not file new general rate cases for new rates to be effective prior to April 1, 2022.

The purpose of our general rate case requests is to recover costs associated with the need to replace infrastructure that has reached the end of its useful life and make technology investments required to build the integrated energy services grid.

Among the projects included in the filing are:

- The upgrade of generating units and other equipment at our Little Falls Dam, which will provide more generating capacity.
- Our distribution grid modernization program that rebuilds and upgrades electric feeders in the system, replacing old equipment like poles, conductor, and transformers to improve service reliability, capture energy efficiency savings and improve operational ability.
- Ongoing management and replacement of electric distribution wood poles through our wood pole management program.
- The ongoing project to systematically replace portions of natural gas distribution pipe in our service area that were installed prior to 1987, as well as replacement of other natural gas service equipment.
- The rebuild of a high voltage transmission line, including the installation of steel poles and crossarms.
- Technology upgrades that support necessary business processes and operational efficiencies.

As a part of these general rate cases, we are also seeking to extend our electric and natural gas decoupling mechanisms for an additional five years (through March 31, 2025). During the second quarter of 2019, we filed a motion to consolidate our ERM filing with our 2019 Washington general rate case and our motion was approved by the WUTC and the ERM refund will now be considered with the 2019 Washington general rate cases.

Idaho General Rate Cases

2017 General Rate Cases

On December 28, 2017, the IPUC approved a settlement agreement between us and other parties to our electric and natural gas general rate cases. New rates were effective on January 1, 2018 and January 1, 2019.

The settlement agreement is a two-year rate plan and has the following electric and natural gas base rate changes each year, which are designed to result in the following increases in annual revenues (dollars in millions):

	Electric		Natural Gas	
Effective Date	Revenue Increase	Base Rate Increase	Revenue Increase	Base Rate Increase
January 1, 2018	$ 12.9	5.2%	$ 1.2	2.9%
January 1, 2019	$ 4.5	1.8%	$ 1.1	2.7%

The settlement agreement is based on a ROR of 7.61 percent with a common equity ratio of 50 percent and a 9.5 percent ROE.

As part of the two-year rate plan the Company will not file a new general rate case for a new rate plan to be effective prior to January 1, 2020.

TCJA Proceedings

On May 31, 2018, the IPUC approved an all-party settlement agreement related to the income tax benefits associated with the TCJA. Effective June 1, 2018, current customer rates were reduced to reflect the reduction of the federal income tax rate to 21 percent, and the amortization of the regulatory liability for plant-related excess deferred income taxes. This reduction reduces annual electric rates by $13.7 million (or 5.3 percent reduction to base rates) and natural gas rates by $2.6 million (or 6.1 percent reduction to base rates).

In March 2019, the IPUC approved an all-party settlement agreement related to the electric tax benefits that were set aside for Colstrip in the 2017 general rate case order. In the approved settlement agreement, the parties agreed to utilize approximately $6.4 million ($5.1 million when tax-effected) of the electric tax benefits to offset costs associated with accelerating the depreciation of Colstrip Units 3 & 4, to reflect a remaining useful life of those units through December 31, 2027. The remaining tax benefits of approximately $5.8 million will be returned to customers through a temporary rate reduction over a period of one year beginning on April 1, 2019. The tax benefits being utilized are related to non-plant excess deferred income taxes, and the customer refund liability that was established in 2018 related to the change in federal income tax expense for the period January 1, 2018 to May 31, 2018.

2019 General Rate Cases

On June 10, 2019, we filed an electric general rate request with the IPUC that is designed to increase annual base electric revenues by $5.3 million (or 2.1 percent). Our request is based on a proposed ROR of 7.55 percent with a common equity ratio of 50.0 percent and a 9.9 percent ROE.

The purpose of our general rate case request is to recover costs associated with the need to replace infrastructure that has reached the end of its useful life and to make technology investments required to build an integrated energy services grid.

Among the projects included in the filing are:

- The upgrade of generating units and other equipment at our Little Falls Dam, which will provide more generating capacity.
- Our distribution grid modernization program that rebuilds and upgrades electric feeders in the system, replacing old equipment such as poles, conductor, and transformers to improve service reliability, capture energy efficiency savings and improve operational ability.
- Ongoing management and replacement of electric distribution wood poles through our wood pole management program.
- The rebuild of substations that have reached the end of their useful life or have reached full capacity.
- Technology upgrades that will support necessary business processes and operational efficiencies.

The IPUC has up to nine months to review the general rate case filings and issue a decision.

Oregon General Rate Cases

2019 General Rate Case

In July 2019, Avista Corp. and all of the parties to our natural gas general rate case filing reached agreement on certain issues, and a partial settlement agreement has been filed with the OPUC for its consideration. The partial settlement includes agreement among the parties on the cost of capital and certain smaller adjustments related to employee benefits and other expenses. In addition, the parties agreed to a future independent review of interest rate hedging practices, with any recommendations based on the results and findings in the final report to be applicable only on a prospective basis and to not apply to any prior interest rate hedging activity. The agreed-upon ROR is 7.24 percent, with a common equity ratio of 50 percent and a 9.4 percent ROE, both of which represent a continuation of existing authorized levels.

The agreement on the elements in the partial settlement results in a reduction in our originally filed revenue increase request from $6.7 million to $5.4 million.

On July 26, 2019, we filed a Motion to Suspend Portions of the Procedural Schedule, noticing the OPUC that all parties in the general rate case have reached a settlement-in-principle resolving all remaining issues in the case. The parties committed to filing the settlement stipulation, supporting testimony, and other documents no later than August 14, 2019.

TCJA Proceedings

In February 2019, the OPUC approved the deferral amount of $3.8 million related to 2018 income tax benefits associated with the TCJA. The 2018 deferred benefits will be returned to customers through a temporary rate reduction over a period of one year beginning March 1, 2019. We will continue the deferral of the TCJA benefits during 2019 for later return to customers, until such time as these changes can be reflected in base rates.

Petition for Judicial Review of the Deferral of Capital Projects

In February 2019 and October 2018, the OPUC issued orders which concluded that, contrary to the OPUC's past practice, Oregon statutes that authorize the deferral of expense for later recovery from customers do not authorize the OPUC to allow deferrals of any costs related to capital investments (utility plant). In April 2019, Avista Corp. and other petitioners filed a Petition for Judicial Review with the Oregon Court of Appeals seeking review of the above OPUC orders. The Company cannot predict the outcome of this matter at this time, including whether or not any decision of the court would have retroactive effect.

AMI Project

In March 2016, the WUTC granted our Petition for an Accounting Order to defer and include in a regulatory asset the undepreciated value of our existing Washington electric meters for the opportunity for later recovery. This accounting treatment is related to our plans to replace our existing electric meters with new two-way digital meters and the related software and support services through our AMI project in Washington State. As of June 30, 2019, the estimated future undepreciated value for the existing electric meters was $21.0 million. In September 2017, the WUTC also approved our request to defer the undepreciated net book value of existing natural gas encoder receiver transmitters (ERT) (consistent with the accounting treatment we obtained on our existing electric meters) that will be retired as part of the AMI project. As of June 30, 2019, the estimated future undepreciated value for the existing natural gas ERTs was $4.2 million. Replacement of the electric meters and natural gas ERTs began during the second half of 2018 and is ongoing.

In September 2017, the WUTC approved a Petition to defer the depreciation expense associated with the AMI project, along with a carrying charge, and to seek recovery of the deferral and carrying charge in a future general rate case. Cost savings, such as reduced meter reading costs, will occur during the implementation period, and will offset a portion of the AMI costs not being deferred.

In May 2017, we filed Petitions with the IPUC and the OPUC requesting a depreciable life of 12.5 years for the meter data management system (MDM) related to the AMI project. Both the IPUC and the OPUC approved our request. In addition, in connection with the 2017 Idaho electric general rate case (discussed above), the settling parties agreed to cost recovery of Idaho's share of the MDM system, effective January 1, 2019. In connection with the approval of the Oregon general rate case settlement (discussed above), the OPUC approved cost recovery of Oregon's share of the MDM system, effective November 1, 2017.

Avista Utilities

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to Avista Utilities' customers with no change in utility margin (operating revenues less resource costs) or net income. 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 that is not hedged. Total net deferred natural gas costs among all jurisdictions were an asset of $2.5 million ($4.3 million in assets and $1.9 million in liabilities) as of June 30, 2019 and a liability of $40.7 million as of December 31, 2018. The liability decreased from the prior year primarily due to higher natural gas prices in 2019 as compared to the current year PGA rates.

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used to track certain differences between Avista Utilities' actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for our Washington customers. Under the ERM, Avista Utilities makes an annual filing on or before April 1 of each year to provide the opportunity for the WUTC staff and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. See the 2018 Form 10-K for a full discussion of the mechanics of the ERM and the various sharing bands. Total net deferred power costs under the ERM were a liability of $35.2 million as of June 30, 2019, compared to a liability of $34.4 million as of December 31, 2018. These deferred power cost balances represent amounts due to customers. Pursuant to WUTC requirements, should the cumulative deferral balance exceed $30 million in the rebate or surcharge direction, we must make a filing with the WUTC to adjust customer rates to either return the balance to customers or recover the balance from customers.

The cumulative rebate balance exceeds $30 million and as a result, our 2019 filing contained a proposed rate refund, effective July 1, 2019 over a three-year period. During the second quarter of 2019 we filed a motion to consolidate this ERM filing with our 2019 Washington general rate case (which was filed on April 30, 2019). In our motion, we requested that the WUTC withhold the refund associated with the ERM for use in the 2019 general rate case rather than passing it back to customers over the three-year period that was proposed in the ERM filing. Our motion was approved by the WUTC and the ERM refund will now be considered with the 2019 Washington general rate cases.

Avista Utilities has a PCA mechanism in Idaho that 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 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 $4.1 million as of June 30, 2019, compared to a liability of $7.6 million as of December 31, 2018. These deferred power cost balances represent amounts due to customers.

Decoupling and Earnings Sharing Mechanisms

Decoupling (also known as a 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, Avista Utilities' electric and natural gas revenues are adjusted so as to be based on the number of customers in certain customer rate classes 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. Only residential and certain commercial customer classes are included in our decoupling mechanisms. See the 2018 Form 10-K for a discussion of the mechanisms in each jurisdiction.

Total net cumulative decoupling deferrals among all jurisdictions were regulatory assets of $19.4 million as of June 30, 2019 and $13.9 million as of December 31, 2018. These decoupling assets represent amounts due from customers. Total net earnings sharing balances among all jurisdictions were regulatory liabilities of $0.9 million as of June 30, 2019 and $1.5 million as of December 31, 2018. These earnings sharing liabilities represent amounts due to customers.

See "Results of Operations - Avista Utilities" for further discussion of the amounts recorded to operating revenues in 2019 and 2018 related to the decoupling and earnings sharing mechanisms.

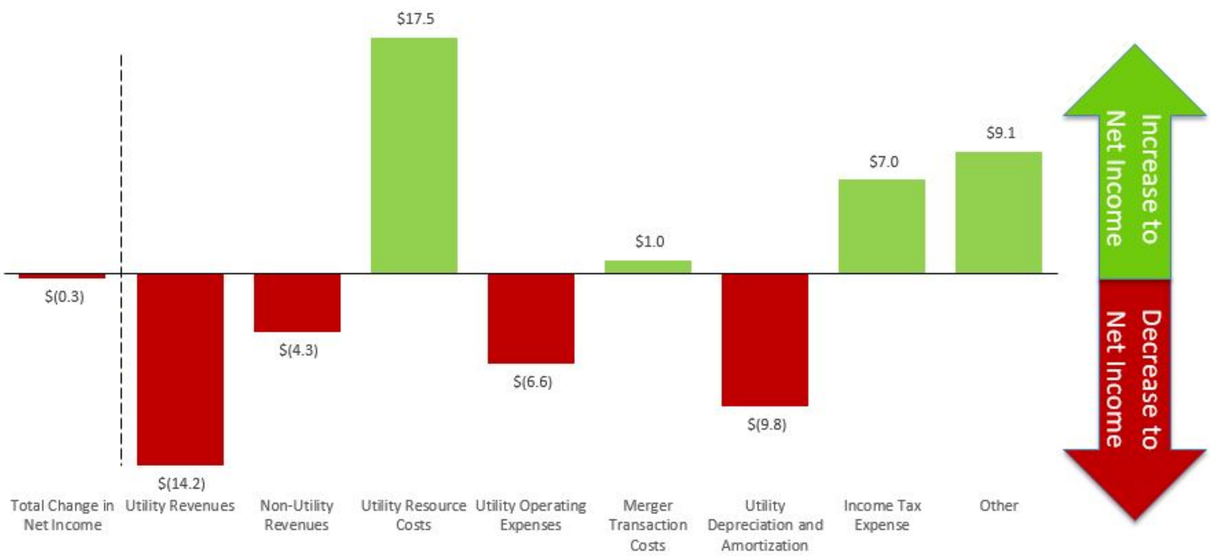
Results of Operations - Overall

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, 2019 compared to the three months ended June 30, 2018

The following graph shows the total change in net income attributable to Avista Corp. shareholders for the second quarter of 2018 to the second quarter of 2019, as well as the various factors that caused such change (dollars in millions):



Utility revenues decreased at both Avista Utilities and AEL&P. Avista Utilities' revenues decreased primarily from a decrease in retail electric and natural gas revenues (primarily from a decrease in decoupling rates and PGA rates, which are included in rates billed to retail customers), as well as a decrease in sales of fuel. These decreases were partially offset by an increase from decoupling, general rate increases and customer growth. AEL&P's revenues decreased due to a decrease in retail rates associated with the federal income tax law change, as well as a decrease in sales volumes due to weather that was warmer than normal and warmer than the prior year.

Non-utility revenues decreased due to the sale of METALfx, which occurred in April 2019.

Utility resource costs decreased at both Avista Utilities and AEL&P. The decrease at Avista Utilities was primarily from a decrease in net power supply costs (resource costs less wholesale revenues) due to lower purchased power prices and natural gas fuel prices. The decrease at AEL&P was due to a decrease in deferred power supply expenses, as well as the adoption of the new lease standard on January 1, 2019, which resulted in the reclassification of Snettisham power purchase costs from resource costs to depreciation and amortization and interest expense in 2019. See "Notes 2 and 5 of the Notes to Condensed Consolidated Financial Statements" for further information regarding the adoption of the new lease standard.

The increase in utility other operating expenses was due to an increase at Avista Utilities. The increase at Avista Utilities was the result of a $7.0 million donation commitment made to fund initiatives to strengthen our local communities, which was recorded in the second quarter 2019. Also, there was an increase in generation, transmission and distribution operating and maintenance costs.

The merger transaction costs are related to the terminated Hydro One acquisition. These costs decreased for the second quarter of 2019 because there were very few activities related to the terminated merger during the second quarter of 2019 other than final wrap-up of the transaction. None of the acquisition costs are being passed through to customers.

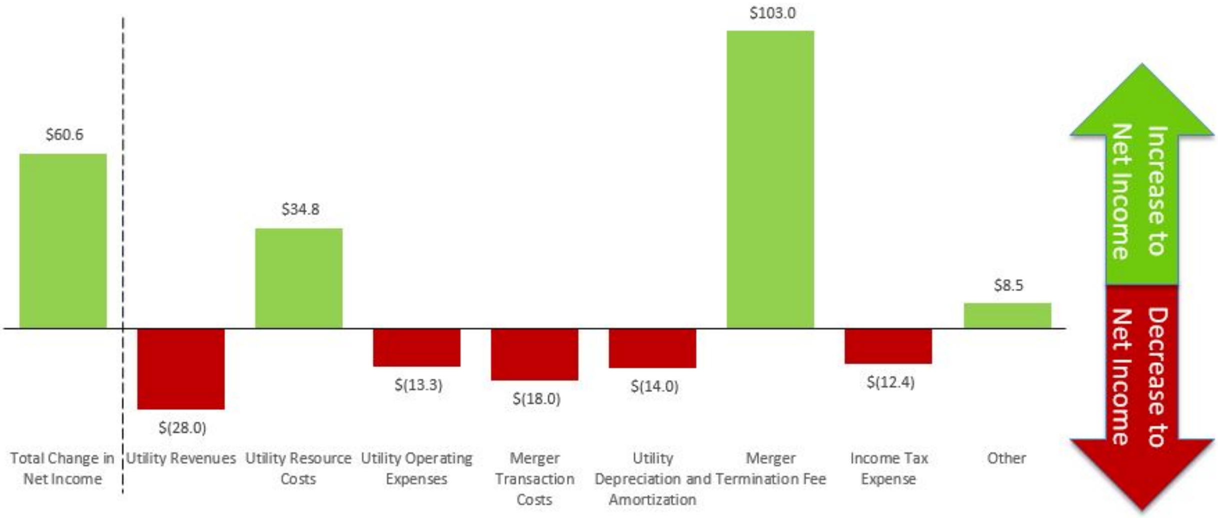
Utility depreciation and amortization increased due to additions to utility plant and from a March 2019 settlement in Idaho, which allowed us to utilize approximately $6.4 million ($5.1 million when tax-effected) of the electric tax benefits to offset costs associated with accelerating the depreciation of Colstrip Units 3 & 4, to reflect a remaining useful life of those units through December 31, 2027. This amount was recorded as a one-time charge to depreciation expense in the second quarter of 2019, with an offsetting amount included in income tax expense.

The increase in other income was primarily related to the gain on the sale of METALfx during the second quarter of 2019. See "Note 18 of the Notes to Condensed Consolidated Financial Statements" for further details of the sales transaction.

Income taxes decreased primarily due to the settlement agreement in Idaho related to Colstrip depreciation and the usage of electric tax benefits to offset the accelerated depreciation. Our effective tax rate was negative 7.5 percent for the second quarter of 2019 compared to 16.9 percent for the second quarter of 2018. We expect our full year 2019 effective tax rate to be approximately 16 percent to 17 percent. See "Note 8 of the Notes to Condensed Consolidated Financial Statements" for further details and a reconciliation of our effective tax rate.

Six months ended June 30, 2019 compared to the six months ended June 30, 2018

The following graph shows the total change in net income attributable to Avista Corp. shareholders for the six months ended June 30, 2018 to the six months ended June 30, 2019, as well as the various factors that caused such change (dollars in millions):



Utility revenues decreased at both Avista Utilities and AEL&P. Avista Utilities' revenues decreased primarily from a decrease in wholesale electric revenues (mostly a decrease in volumes), as well as a decrease in sales of fuel. These items decreased due to lower than normal hydroelectric generation, which resulted in less optimization of the system. These decreases were partially offset by general rate increases and customer growth. AEL&P's revenues decreased due to a decrease in retail rates associated with the federal income tax law change, as well as a decrease in sales volumes due to weather that was warmer than normal and warmer than the prior year.

Utility resource costs decreased at both Avista Utilities and AEL&P. The decrease at Avista Utilities was primarily from a decrease in net power supply costs (resource costs less wholesale revenues) due to lower purchased power prices, partially offset by an increase in natural gas resource costs. The decrease at AEL&P was due to a decrease in deferred power supply expenses, as well as the adoption of the new lease standard on January 1, 2019. See "Notes 2 and 5 of the Notes to Condensed Consolidated Financial Statements" for further information regarding the adoption of the new lease standard.

The increase in utility other operating expenses was due to an increase at Avista Utilities and a slight increase at AEL&P. The increase at Avista Utilities was the result of the donation commitment described above, which was recorded in the second quarter 2019. Also, there was an increase in generation, transmission and distribution operating and maintenance costs.

The merger transaction costs are related to the terminated Hydro One acquisition. These costs increased for the year-to-date 2019 because 2019 includes financial advisers' fees, legal fees, consulting fees and employee time, whereas the second quarter of 2018 consisted primarily of employee time incurred directly related to the transaction. None of the acquisition costs are being passed through to customers.

Utility depreciation and amortization increased mainly due to the settlement in Idaho described above, as well as additions to utility plant.

The merger termination fee was received from Hydro One due to the mutual agreement to terminate the proposed acquisition. See "Note 17 of the Notes to Condensed Consolidated Financial Statements" for additional discussion.

The increase in other was primarily related to the gain on the sale of METALfx during the second quarter of 2019. Also, 2018 included an impairment of an investment and additional charges associated with a renovation, whereas 2019 included earnings from our investments. See "Note 18 of the Notes to Condensed Consolidated Financial Statements" for further details of the sales transaction.

Income taxes decreased primarily due to the settlement agreement in Idaho related to Colstrip depreciation. Our effective tax rate was 16.7 percent for 2019, compared to 16.5 percent for 2018. We expect our full year 2019 effective tax rate to be approximately 16 percent to 17 percent. See "Note 8 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 that are considered “non-GAAP financial measures”: electric utility margin and natural gas utility margin. In the AEL&P section, we include a discussion of utility margin, which is also a non-GAAP financial measure.

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 that are 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."

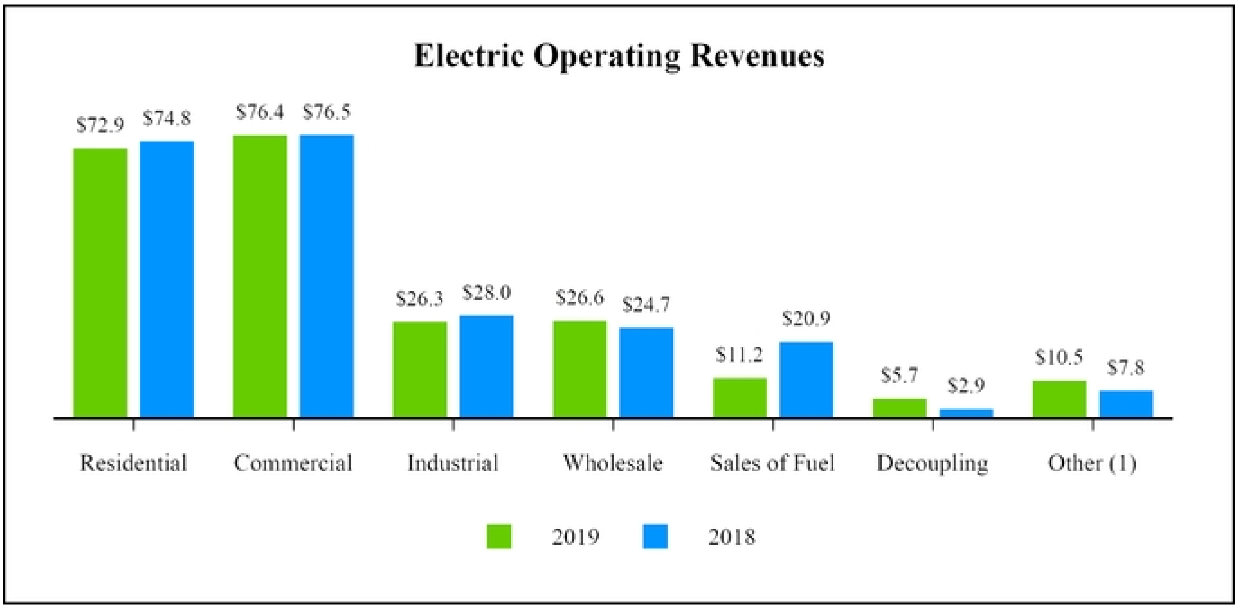
The presentation of electric utility margin and natural gas utility margin is intended to enhance the understanding of operating performance. We use these measures internally and believe they provide useful information to investors in their analysis of how changes in loads (due to weather, economic or 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 that 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

Three months ended June 30, 2019 compared to the three months ended June 30, 2018

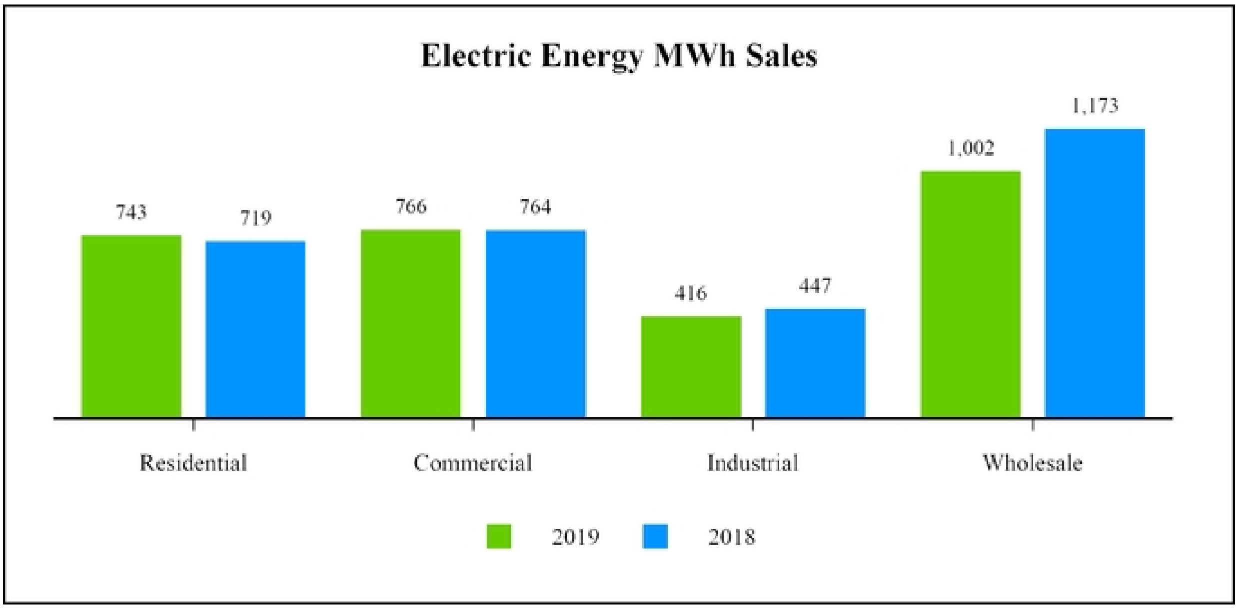
Utility Operating Revenues

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



(1) This balance includes public street and highway lighting, which is considered part of retail electric revenues, and deferrals/amortizations to customers related to federal income tax law changes.

Total electric operating revenues in the graph above include intracompany sales of $6.0 million and $2.0 million for the three months ended June 30, 2019 and June 30, 2018, respectively.



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

	Electric Decoupling Revenues	
	2019	2018
Current year decoupling deferrals (a)	$ 5,159	$ 6,274
Amortization of prior year decoupling deferrals (b)	533	(3,396)
Total electric decoupling revenue	$ 5,692	$ 2,878

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

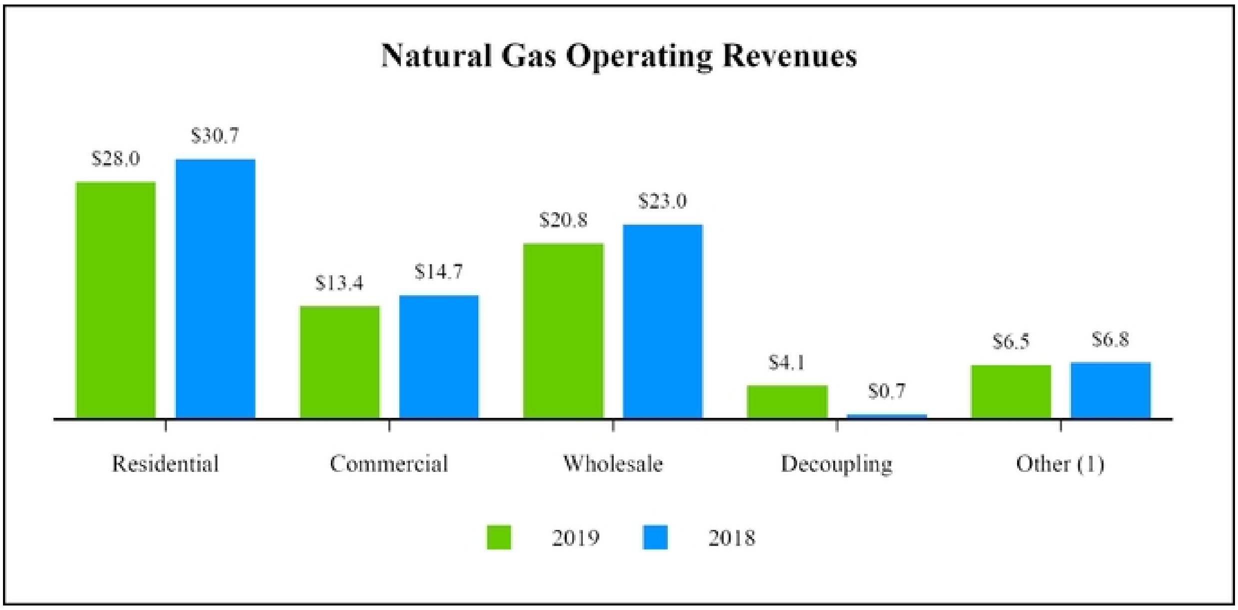
(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative numbers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

Total electric revenues decreased $6.0 million for the second quarter of 2019 as compared to the second quarter of 2018 primarily due to the following:

- a $3.8 million decrease in retail electric revenue due to a decrease in total MWhs sold (decreased revenues $0.5 million) and a decrease in revenue per MWh (decreased revenues $3.3 million).
    - The slight decrease in total retail MWhs sold was the result of a decrease in industrial sales volumes, partially offset by an increase in residential sales volumes and customer growth. Compared to the second quarter of 2018, residential electric use per customer increased 2 percent and commercial use per customer decreased 1 percent. Heating degree days in Spokane were 23 percent below normal and consistent with the second quarter of 2018. Cooling degree days in Spokane were 42 percent above normal and 62 percent above the second quarter of 2018.
    - The decrease in revenue per MWh was primarily due to a decrease in decoupling rates (as our decoupling surcharges were larger in prior years, which resulted in higher surcharge rates in 2018 as compared to rebates in 2019) and decreases associated with the lower corporate tax rate. This was partially offset by general rate increases in Washington (effective May 1, 2018) and Idaho (effective January 1, 2019).

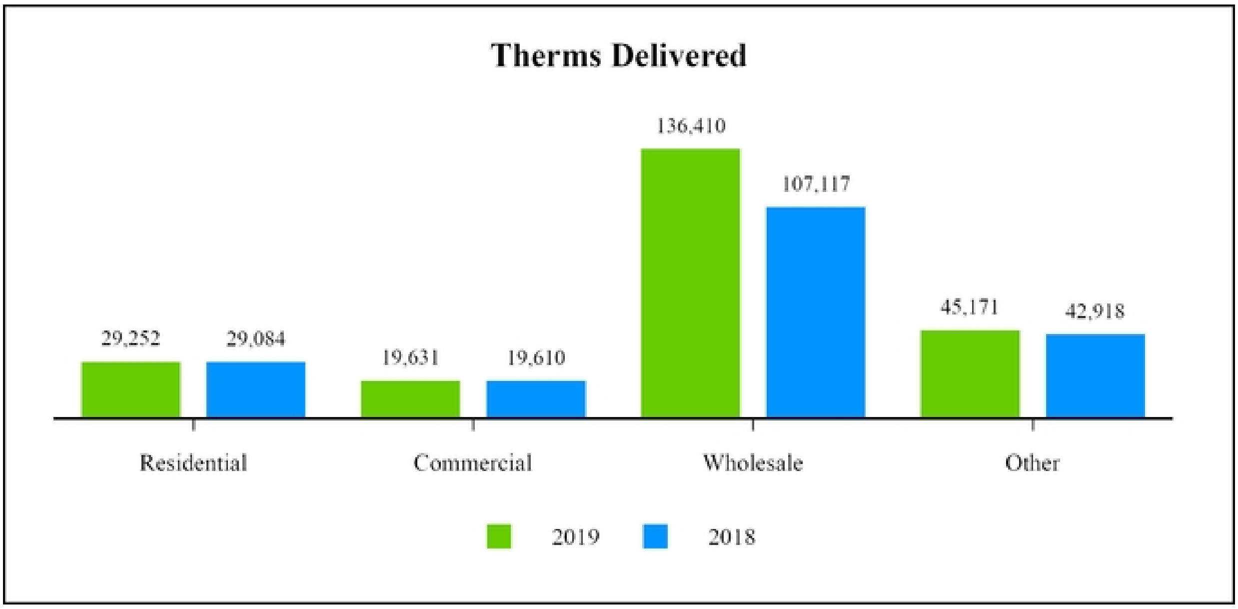
- a $1.9 million increase in wholesale electric revenues due to an increase in sales prices (increased revenues $6.4 million), partially offset by a decrease in sales volumes (decreased revenues $4.5 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $9.7 million decrease in sales of fuel due to a decrease in sales of natural gas fuel as part of thermal generation resource optimization activities.
- a $2.8 million increase in electric decoupling revenue. Weather was warmer than normal in the second quarter of 2019, reducing the demand for electric heating, which resulted in decoupling deferral surcharges related to the current year. There was also the amortization of decoupling rebates from prior years.
- the $2.7 million increase in other electric revenues was primarily related to federal income tax law changes that lowered the corporate tax rate from 35 percent to 21 percent. As our customers' rates had the 35 percent corporate tax rate built in from prior general rate cases, we deferred the impact of the change in the first quarter of 2018. Effective May 1, 2018 in Washington and June 1, 2018 in Idaho, base rates reflect the lower 21 percent corporate tax.

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



(1) This balance includes interruptible and industrial revenues, which are considered part of retail natural gas revenues, and deferrals/amortizations to customers related to federal income tax law changes.

Total natural gas operating revenues in the graph above include intracompany sales of $6.5 million and $7.3 million for the three months ended June 30, 2019 and June 30, 2018, respectively.



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

	Natural Gas Decoupling Revenues	
	2019	2018
Current year decoupling deferrals (a)	$ 3,138	$ 2,458
Amortization of prior year decoupling deferrals (b)	895	(1,767)
Total natural gas decoupling revenue	$ 4,033	$ 691

(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative numbers are decreases in decoupling revenue in the current year 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 and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative numbers are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

Total natural gas revenues decreased $3.2 million for the second quarter of 2019 as compared to the second quarter of 2018 primarily due to the following:

- a $4.1 million decrease in natural gas retail revenues due to lower retail rates (decreased revenues $4.9 million), partially offset by an increase in volumes (increased revenues $0.8 million).
  - We sold more retail natural gas in the second quarter of 2019 as compared to the second quarter of 2018 primarily due to customer growth as use per customer decreased slightly due to warmer weather. Compared to second quarter of 2018, residential use per customer decreased 2 percent and commercial use per customer decreased 1 percent. Heating degree days in Spokane were 23 percent below normal, and consistent with the second quarter of 2018. Heating degree days in Medford were 24 percent below normal, and 1 percent below the second quarter of 2018.
  - Lower retail rates were due to PGAs and rate decreases associated with the lower corporate tax rate and decoupling rate decreases (as our decoupling surcharges were larger in prior years, which resulted in higher surcharge rates in 2018 as compared to rebates in 2019), partially offset by general rate increases in Washington (effective May 1, 2018) and Idaho (effective January 1, 2019).

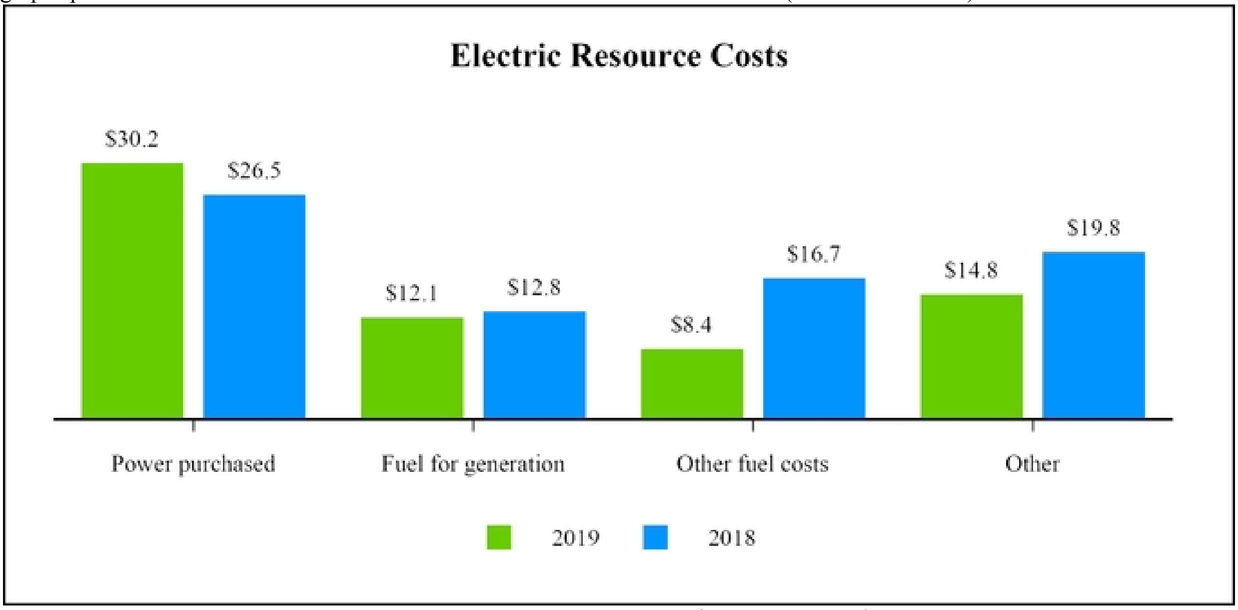
- a $2.2 million decrease in wholesale natural gas revenues due to a decrease in prices (decreased revenues $6.7 million), partially offset by an increase in volumes (increased revenues $4.5 million). Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.
- a $3.4 million increase in natural gas decoupling revenue. Weather was warmer than normal in the second quarter of 2019, reducing the demand for natural gas heating, which resulted in decoupling deferral surcharges related to the current year. There was also the amortization of decoupling rebates from prior years.

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

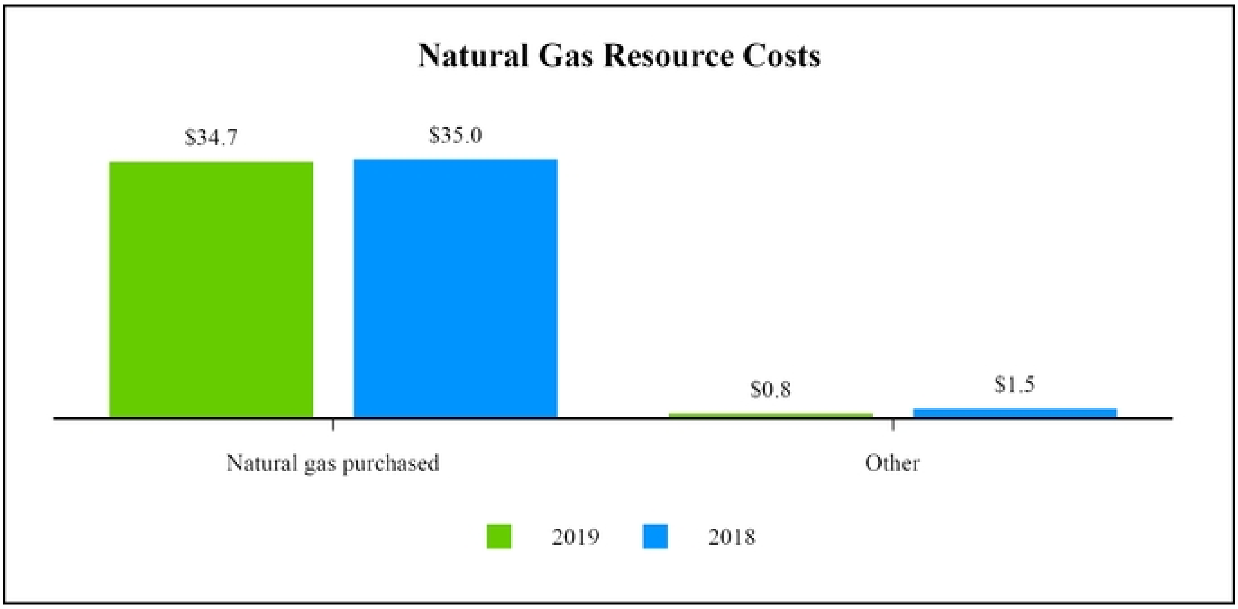
	Electric Customers		Natural Gas Customers	
	2019	2018	2019	2018
Residential	344,342	339,010	321,136	313,782
Commercial	42,922	42,539	35,835	35,480
Interruptible	—	—	48	39
Industrial	1,307	1,312	241	246
Public street and highway lighting	606	594	—	—
Total retail customers	389,177	383,455	357,260	349,547

Utility Resource Costs

The following graphs present Avista Utilities' resource costs for the three months ended June 30 (dollars in millions):



Total electric resource costs in the graph above include intracompany resource costs of $6.5 million and $7.3 million for the three months ended June 30, 2019 and June 30, 2018, respectively.



Total natural gas resource costs in the graph above include intracompany resource costs of $6.0 million and $2.0 million for the three months ended June 30, 2019 and June 30, 2018, respectively.

Total electric resource costs decreased $10.2 million for the second quarter of 2019 as compared to the second quarter of 2018 primarily due to the following:

- a $3.7 million increase in purchased power costs due to an increase in wholesale prices (increased costs $8.0 million), partially offset by a decrease in the volume of power purchases (decreased costs $4.3 million). The fluctuation in volumes and prices was primarily the result of our optimization activities during the quarter.
- a $0.7 million decrease in fuel for generation primarily due to a slight decrease in thermal generation volumes.
- an $8.3 million decrease in other fuel costs. This represents fuel and the related derivative instruments that were purchased for generation but were later sold when conditions indicated that it was more economical to sell the fuel as part of the resource optimization process. When the fuel or related derivative instruments are sold, that revenue is included in sales of fuel.
- a $6.2 million decrease from net amortizations and deferrals of power costs.
- a $1.2 million net increase from other regulatory amortizations and other electric resource costs.

Total natural gas resource costs decreased $1.0 million for the second quarter of 2019 as compared to the second quarter of 2018 primarily due to the following:

- a $0.3 million decrease in natural gas purchased due to a decrease in the price of natural gas (decreased costs $5.9 million), partially offset by an increase in total therms purchased (increased costs $5.6 million).
- a $1.1 million decrease from net amortizations and deferrals of natural gas costs.
- a $0.4 million increase from other regulatory amortizations.

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 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2019	2018	2019	2018	2019	2018	2019	2018
Operating revenues	$ 229,591	$ 235,558	$ 72,766	$ 75,946	$ (12,549)	$ (9,282)	$ 289,808	$ 302,222
Resource costs	65,564	75,766	35,491	36,538	(12,549)	(9,282)	88,506	103,022
Utility margin	$ 164,027	$ 159,792	$ 37,275	$ 39,408	$ —	$ —	$ 201,302	$ 199,200

Electric utility margin increased $4.2 million and natural gas utility margin decreased $2.1 million.

Electric utility margin increased primarily due to a decrease in net power supply costs. The decrease in net power supply costs was due to lower purchased power prices and natural gas fuel prices. For the second quarter of 2019, we had a $6.0 million pre-tax benefit under the ERM in Washington, compared to a $1.0 million pre-tax benefit for the second quarter of 2018. For the full year of 2019, we expect to be in a benefit position under the ERM within the 75 percent customer/25 percent Company sharing band.

Electric utility margin was also positively impacted by general rate increases in Washington (effective May 1, 2018) and Idaho (effective January 1, 2019), and customer growth.

Natural gas utility margin benefited in the second quarter of 2018 from the implementation of new base rates implemented on May 1, 2018 in Washington and June 1, 2018 in Idaho to reflect the lower 21 percent corporate tax rate. During the first quarter of 2018, we estimated the impact of the change in the base rates. This estimate was reduced in the second quarter of 2018 based on commission orders.

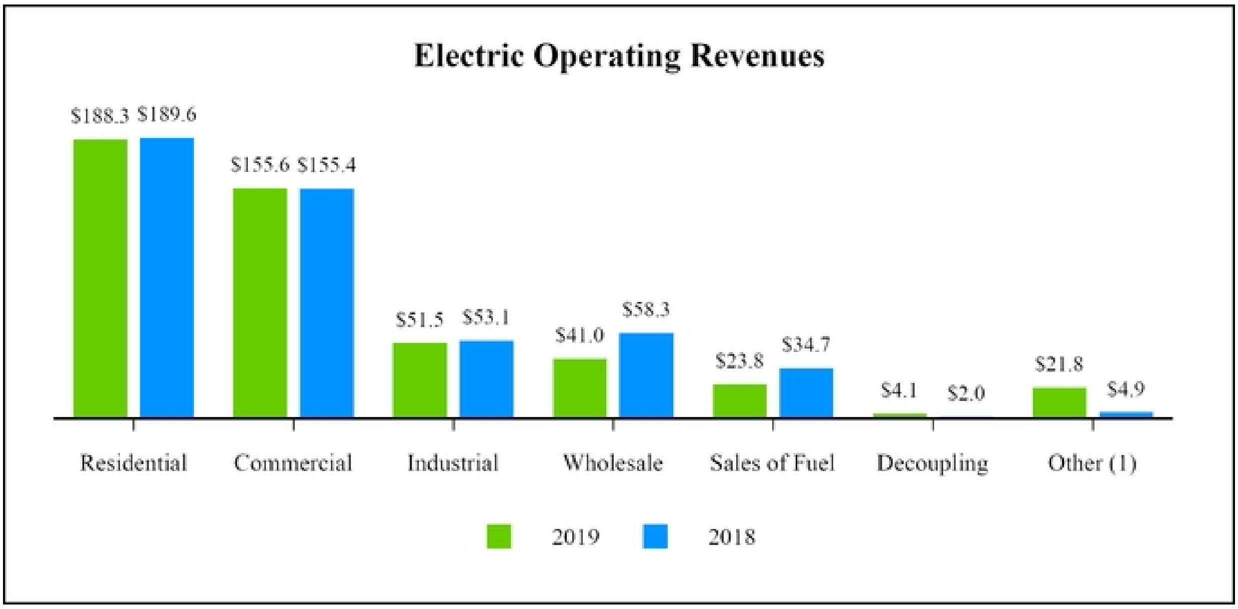
Offsetting the impact of changes in the corporate tax rate, natural gas utility margin was positively impacted by general rate increases in Washington (effective May 1, 2018) and Idaho (effective January 1, 2019), and customer growth.

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, 2019 compared to the six months ended June 30, 2018

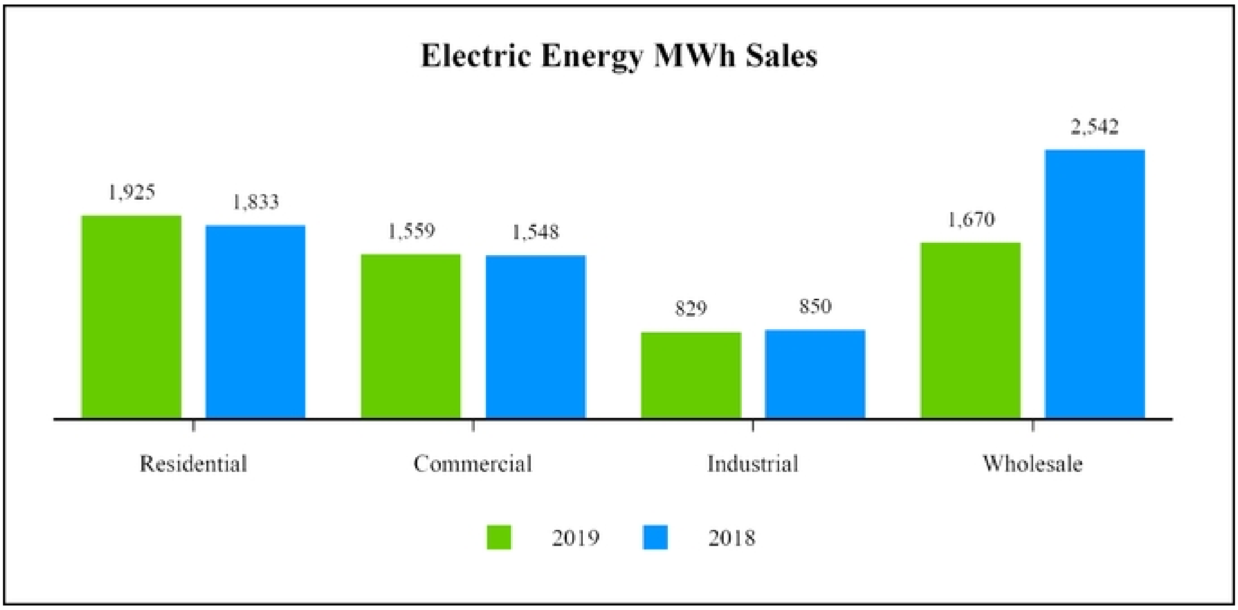
Utility Operating Revenues

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



(1) This balance includes public street and highway lighting, which is considered part of retail electric revenues, and deferrals/amortizations to customers related to federal income tax law changes.

Total electric operating revenues in the graph above include intracompany sales of $25.7 million and $8.9 million for the six months ended June 30, 2019 and June 30, 2018, respectively.



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

	Electric Decoupling Revenues	
	2019	2018
Current year decoupling deferrals (a)	$ 2,478	$ 10,286
Amortization of prior year decoupling deferrals (b)	1,609	(8,276)
Total electric decoupling revenue	$ 4,087	$ 2,010

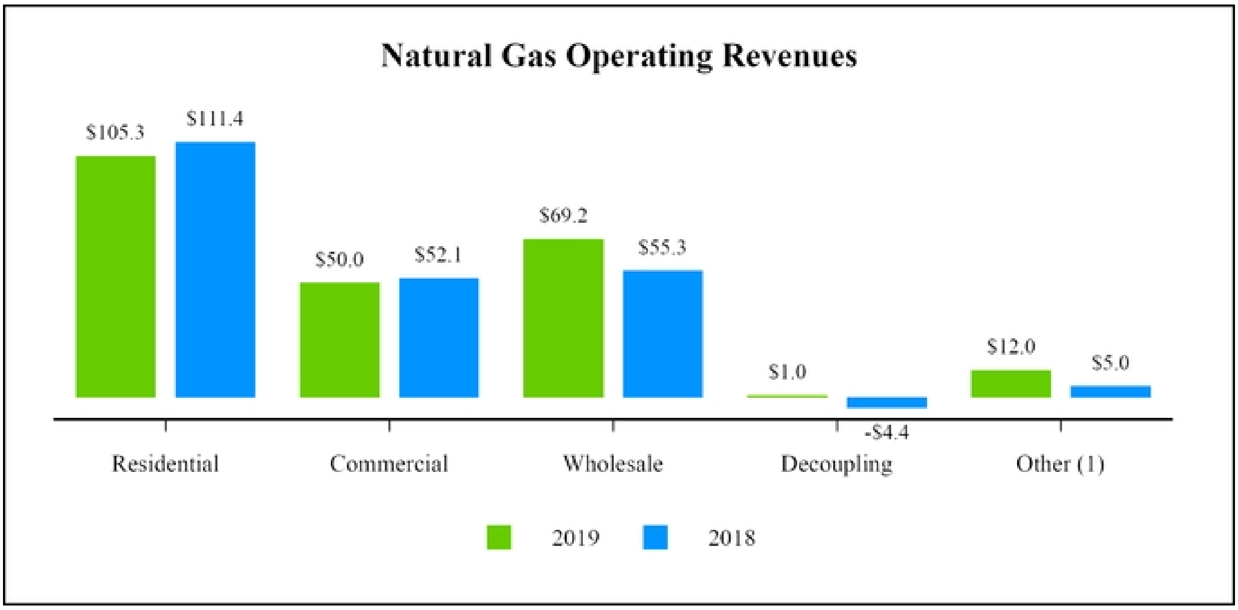
(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative numbers are decreases in decoupling revenue in the current year and will be rebated to customers in future years.

(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 and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative numbers are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

Total electric revenues decreased $12.0 million for the six months ended June 30, 2019 as compared to the six months ended June 30, 2018 primarily due to the following:

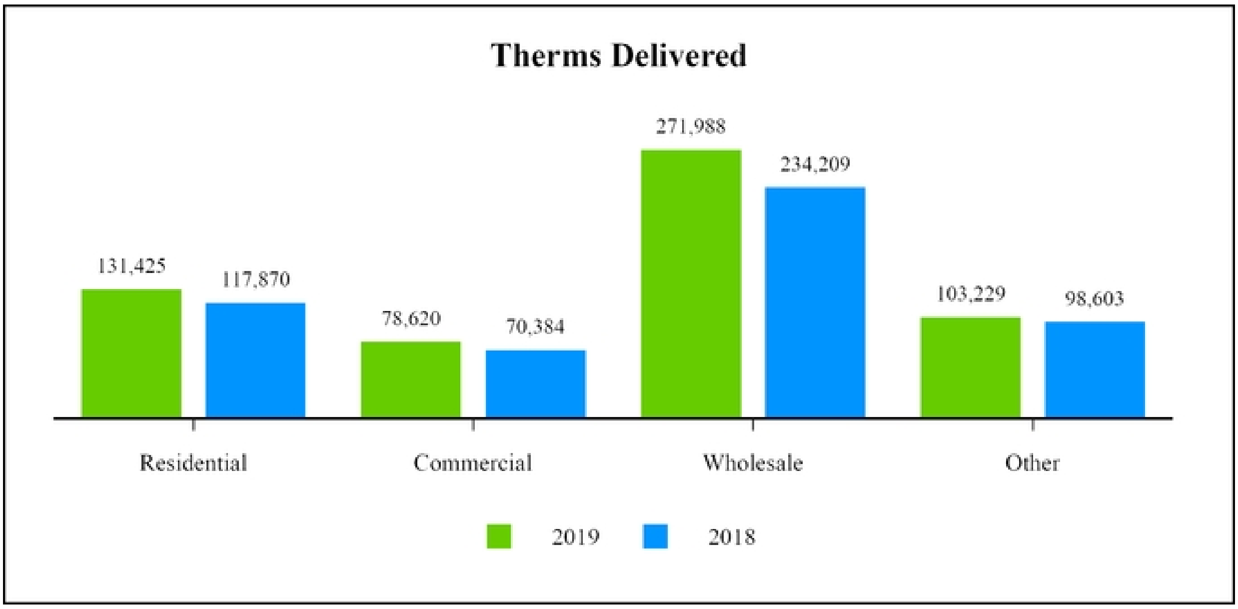
- a $2.6 million decrease in retail electric revenue due to a decrease in revenue per MWh (decreased revenues $10.1 million), partially offset by an increase in total MWhs sold (increased revenues $7.5 million).
    - The decrease in revenue per MWh was primarily due to a decrease in decoupling rates (as our decoupling surcharges were larger in prior years, which resulted in higher surcharge rates in 2018 as compared to rebates in 2019) and decreases associated with the lower corporate tax rate. This was partially offset by general rate increases in Washington (effective May 1, 2018) and Idaho (effective January 1, 2019).
    - The increase in total retail MWhs sold was the result of weather that was cooler than the prior year during the first quarter heating season (which increased electric heating loads), and customer growth. Compared to the six months ended June 30, 2018, residential electric use per customer increased 3 percent and commercial use per customer was relatively consistent. Heating degree days in Spokane were 4 percent above normal and 13 percent above the first six months of 2018. Year-to-date 2019 cooling degree days were 42 percent above normal and 62 percent above the prior year.
- a $17.3 million decrease in wholesale electric revenues due to a decrease in sales volumes (decreased revenues $21.4 million), partially offset by an increase in sales prices (increased revenues $4.1 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $10.9 million decrease in sales of fuel due to a decrease in sales of natural gas fuel as part of thermal generation resource optimization activities.
- a $2.1 million increase in electric revenue due to decoupling.
- the $16.9 million increase in other electric revenues was primarily related to federal income tax law changes that lowered the corporate tax rate from 35 percent to 21 percent. As our customers' rates had the 35 percent corporate tax rate built in from prior general rate cases, we deferred the impact of the change in the first quarter of 2018. Effective May 1, 2018 in Washington and June 1, 2018 in Idaho, base rates reflect the lower 21 percent corporate tax.

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



(1) This balance includes interruptible and industrial revenues, which are considered part of retail natural gas revenues, and deferrals/amortizations to customers related to federal income tax law changes.

Total natural gas operating revenues in the graph above include intracompany sales of $30.3 million and $17.6 million for the six months ended June 30, 2019 and June 30, 2018, respectively.



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

	Natural Gas Decoupling Revenues	
	2019	2018
Current year decoupling deferrals (a)	$ (2,968)	$ 2,606
Amortization of prior year decoupling deferrals (b)	3,948	(6,986)
Total natural gas decoupling revenue	$ 980	$ (4,380)

(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative numbers are decreases in decoupling revenue in the current year 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 and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative numbers are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

Total natural gas revenues increased $18.0 million for the six months ended June 30, 2019 as compared to the six months ended June 30, 2018 primarily due to the following:

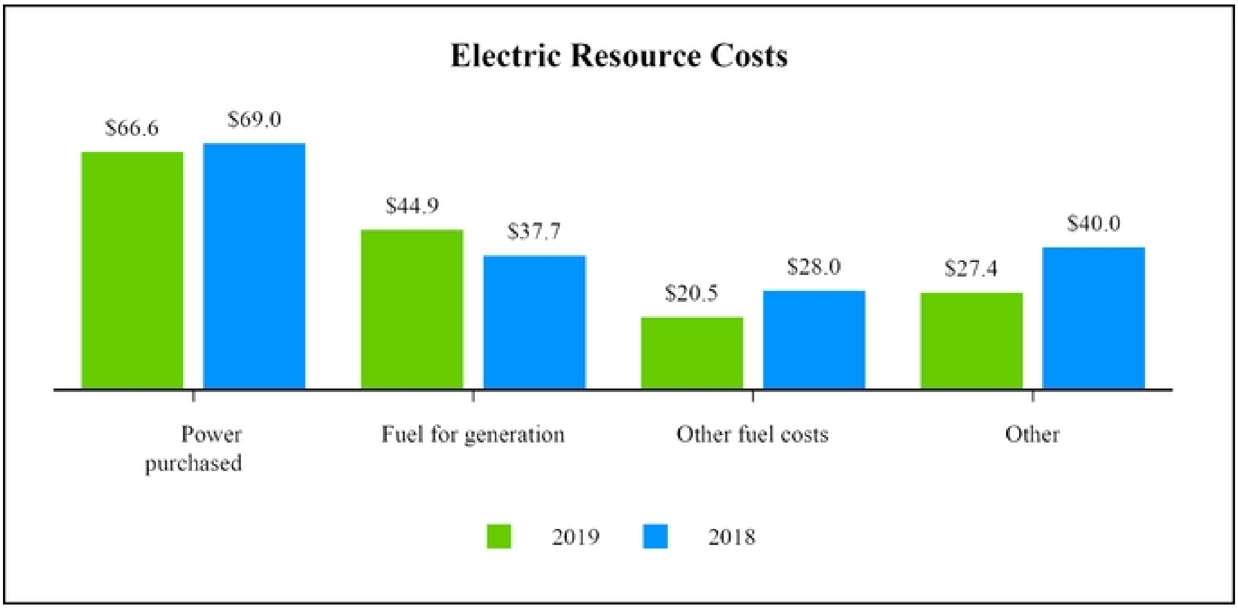
- an $8.3 million decrease in natural gas retail revenues due lower retail rates (decreased revenues $25.5 million), partially offset by an increase in volumes (increased revenues $17.2 million).
    - We sold more retail natural gas in the six months ended June 30, 2019 as compared to the six months ended June 30, 2018 due to cooler weather during the heating season, and customer growth. Compared to the first six months of 2018, residential natural gas use per customer increased 9 percent and commercial use per customer increased 11 percent. Heating degree days in Spokane were 4 percent above normal and 13 percent above the first six months of 2018. Heating degree days in Medford were 1 percent above normal, and 6 percent above the first six months of 2018.
    - Lower retail rates were due to PGAs and rate decreases associated with the lower corporate tax rate and decoupling rate decreases (as our decoupling surcharges were larger in prior years, which resulted in higher surcharge rates in 2018 as compared to rebates in 2019), partially offset by general rate increases in Washington (effective May 1, 2018) and Idaho (effective January 1, 2019).
- a $13.9 million increase in wholesale natural gas revenues due to an increase in prices (increased revenues $4.3 million) and an increase in volumes (increased revenues $9.6 million). 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 $5.4 million increase in natural gas revenue due to decoupling. Weather was cooler than normal in the first six months of 2019, which increased demand for natural gas heating, which resulted in decoupling rebates related to the current year. This was partially offset by the amortization of decoupling rebates from prior years.
- the $7.1 million increase in other natural gas revenues was primarily related to federal income tax law changes that lowered the corporate tax rate from 35 percent to 21 percent. As our customers' rates had the 35 percent corporate tax rate built in from prior general rate cases, we deferred the impact of the change beginning January 1, 2018. Effective May 1, 2018 in Washington, June 1, 2018 in Idaho and March 1, 2019 in Oregon, base rates reflect the lower 21 percent corporate tax.

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

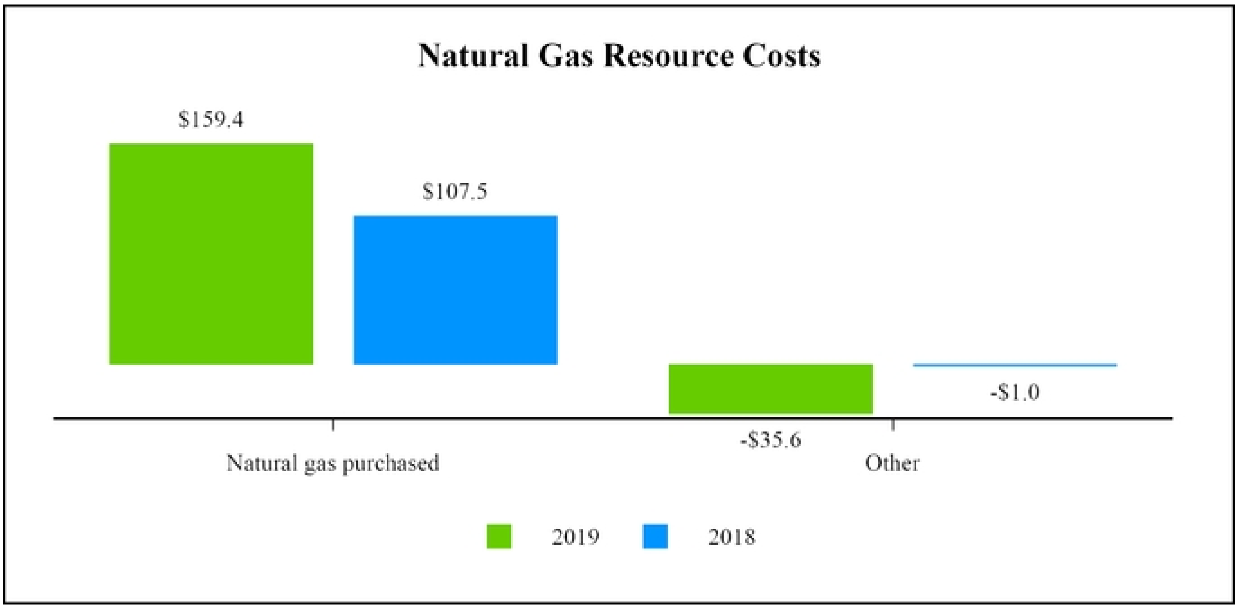
	Electric Customers		Natural Gas Customers	
	2019	2018	2019	2018
Residential	344,140	339,114	320,309	313,515
Commercial	42,898	42,582	35,771	35,493
Interruptible	—	—	45	39
Industrial	1,310	1,317	240	247
Public street and highway lighting	604	591	—	—
Total retail customers	388,952	383,604	356,365	349,294

Utility Resource Costs

The following graphs present Avista Utilities' resource costs for the six months ended June 30 (dollars in millions):



Total electric resource costs in the graph above include intracompany resource costs of $30.3 million and $17.6 million for the six months ended June 30, 2019 and June 30, 2018, respectively.



Total natural gas resource costs in the graph above include intracompany resource costs of $25.7 million and $8.9 million for the six months ended June 30, 2019 and June 30, 2018, respectively.

Total electric resource costs decreased $15.2 million for the six months ended June 30, 2019 as compared to the six months ended June 30, 2018 primarily due to the following:

- a $2.4 million decrease in purchased power due to a decrease in the volume of power purchases (decreased costs $15.3 million), partially offset by an increase in wholesale prices (increased costs $12.9 million). The fluctuation in volumes and prices was primarily the result of our optimization activities during the period.
- a $7.2 million increase in fuel for generation primarily due to an increase in thermal generation, as well as natural gas fuel prices.
- a $7.5 million decrease in other fuel costs. This represents fuel and the related derivative instruments that were purchased for generation but were later sold when conditions indicated that it was more economical to sell the fuel as part of the resource optimization process. When the fuel or related derivative instruments are sold, that revenue is included in sales of fuel.
- a $17.3 million decrease from amortizations and deferrals of power costs.
- a $4.7 million increase in other regulatory amortizations and other electric resource costs.

Total natural gas resource costs increased $17.3 million for the six months ended June 30, 2019 as compared to the six months ended June 30, 2018 primarily due to the following:

- a $51.9 million increase in natural gas purchased due to an increase in the price of natural gas (increased costs $31.9 million) and an increase in total therms purchased (increased costs $20.0 million). Total therms purchased increased due to an increase in retail sales and wholesale sales.
- a $36.8 million decrease from amortizations and deferrals of natural gas costs, primarily reflecting higher natural gas prices.
- a $2.2 million increase in other regulatory amortizations.

Utility Margin

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

	Electric		Natural Gas		Intracompany		Total	
	2019	2018	2019	2018	2019	2018	2019	2018
Operating revenues	$ 486,058	$ 498,035	$ 237,443	$ 219,394	$ (55,991)	$ (26,453)	$ 667,510	$ 690,976
Resource costs	159,445	174,656	123,764	106,484	(55,991)	(26,453)	227,218	254,687
Utility margin	$ 326,613	$ 323,379	$ 113,679	$ 112,910	$ —	$ —	$ 440,292	$ 436,289

Electric utility margin increased $3.2 million and natural gas utility margin increased $0.8 million.

Electric utility margin was positively impacted during 2019 by general rate increases in Idaho (effective January 1, 2019) and Washington (effective May 1, 2018), as well as customer growth. For the six months ended June 30, 2019, we recognized a pre-tax benefit of $3.5 million under the ERM in Washington compared to a benefit of $5.8 million for the six months ended June 30, 2018. For the full year of 2019, we expect to be in a benefit position under the ERM within the 75 percent customer/25 percent Company sharing band.

Natural gas utility margin was positively impacted by general rate increases in Washington (effective May 1, 2018) and Idaho (effective January 1, 2019), and customer growth.

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

Three months ended June 30, 2019 compared to the three months ended June 30, 2018 and six months ended June 30, 2019 compared to the six months ended June 30, 2018

Net income for AEL&P was $1.1 million for the three months ended June 30, 2019 compared to $1.3 million for the three months ended June 30, 2018. Net income was $4.6 million for the six months ended June 30, 2019 compared to $5.1 million for the six months ended June 30, 2018.

The following table presents AEL&P's operating revenues, resource costs and resulting utility margin for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	2019	2018
Operating revenues	$ 8,743	$ 10,482	$ 19,624	$ 24,145
Resource costs	(67)	2,947	(1,432)	5,900
Utility margin	$ 8,810	$ 7,535	$ 21,056	$ 18,245

Electric revenues decreased for the second quarter and year-to-date 2019 primarily due to lower sales volumes to residential and commercial customers for 2019 as compared to 2018. This resulted from weather that was warmer than normal and warmer than the prior year.

Resource costs decreased from the prior year due to the adoption of the new lease standard on January 1, 2019, which resulted in the reclassification of Snettisham power purchase costs from resource costs to depreciation and amortization and interest expense in 2019. See "Notes 2 and 5 of the Notes to Condensed Consolidated Financial Statements" for further information regarding the adoption of the new lease standard. In addition, AEL&P had low hydroelectric generation during the first half of 2019, which limited energy provided to their interruptible customers. A portion of the sales to interruptible customers is used to reduce the overall cost of power to AEL&P's firm customers. When interruptible sales are below a certain threshold, AEL&P recognizes a regulatory asset and records a reduction to deferred power supply costs (resource costs) to reflect a future billable amount to its firm customers when the cost of power rates are reset.

Results of Operations - Other Businesses

Net income for our other businesses was $3.0 million for the three months ended June 30, 2019 compared to net income of less than $0.1 million for the three months ended June 30, 2018. Net income was $3.4 million for the six months ended June 30, 2019 compared to net losses of $4.4 million for the six months ended June 30, 2018.

During the second quarter of 2019, we sold METALfx, which resulted in a net gain after-tax of approximately $2.3 million. See "Note 18 of the Notes to Condensed Consolidated Financial Statements" for further discussion of the sale of METALfx.

In addition, during 2019 we had net investment gains associated with our equity investments. This is compared to investment losses during 2018 primarily from an impairment of one of our investments and expenses associated with a renovation project.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with GAAP requires us to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on our 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 2018 Form 10-K and have not changed materially from that discussion.

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, 2019. See the 2018 Form 10-K for further discussion.

As of June 30, 2019, we had $212.4 million of available liquidity under the Avista Corp. committed line of credit and $25.0 million under the AEL&P committed line of credit. With our $400.0 million credit facility that expires in April 2021 and AEL&P's $25.0 million credit facility that expires in November 2019, we believe that we have adequate liquidity to meet our needs for the next 12 months. We anticipate pursuing an extension to the AEL&P credit facility or entering into a new agreement during 2019.

Review of Cash Flow Statement

Operating Activities

Net cash provided by operating activities was $252.7 million for the six months ended June 30, 2019 compared to $275.4 million for the six months ended June 30, 2018. The decrease in net cash provided by operating activities was primarily due to power and natural gas deferrals which increased during 2019 due to higher natural gas prices during the year (which decreased cash flows by $47.7 million) as compared to an increase to operating cash flows of $6.7 million in 2018. As compared to 2018, changes in accounts receivable resulted in a decrease to operating cash flows of $18.1 million.

The above decreases were partially offset by the receipt of the $103.0 million merger termination fee from Hydro One that is reflected in net income for 2019. The termination fee was used for reimbursing our transaction costs incurred from 2017 to 2019 which totaled approximately $51.0 million, including income taxes. The balance of the termination fee was used for general corporate purposes and reduced our need for external financing. Our total transaction costs were $19.7 million (pre-tax) for 2019 and we also incurred approximately $15.7 million in taxes in 2019 (net of $1.8 million in tax benefits recaptured from 2017 and 2018).

Investing Activities

Net cash used in investing activities was $190.0 million for the six months ended June 30, 2019, compared to $192.9 million for the six months ended June 30, 2018. During the six months ended June 30, 2019, we paid $200.0 million for utility capital expenditures compared to $183.1 million for the six months ended June 30, 2018. Also, during 2019, we received proceeds from the sale of METALfx (net of cash sold and amounts held in escrow) of $16.4 million. This amount is prior to the payment of transaction costs, which are reflected in operating activities.

Financing Activities

Net cash used by financing activities was $60.1 million for the six months ended June 30, 2019, compared to $63.4 million for the six months ended June 30, 2018. Due to the receipt of the termination fee described above, we were able to reduce our short-term borrowings during 2019, as evidenced by the $21.0 million decrease in short-term borrowings. Also, during 2019 we issued $14.9 million of common stock, most of which was under our sales agency agreements in the second quarter.

During 2018, we issued $374.6 million in long-term debt and repaid $276.2 million, as well as paid off $105.4 million of borrowings on our committed line of credit.

Capital Resources

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings, and excluding noncontrolling interests, consisted of the following as of June 30, 2019 and December 31, 2018 (dollars in thousands):

	June 30, 2019		December 31, 2018	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt and leases (1)	$ 111,846	2.8%	$ 107,645	2.8%
Short-term borrowings	169,000	4.2%	190,000	4.9%
Long-term debt to affiliated trusts	51,547	1.3%	51,547	1.3%
Long-term debt and leases (1)	1,822,812	45.1%	1,755,529	45.3%
Total debt	2,155,205	53.4%	2,104,721	54.3%
Total Avista Corporation shareholders’ equity	1,884,034	46.6%	1,773,220	45.7%
Total	$ 4,039,239	100.0%	$ 3,877,941	100.0%

(1) Effective, January 1, 2019, we adopted ASC 842 which resulted in the reclassification of the Snettisham lease from long-term debt, to lease liabilities in 2019. The Snettisham lease amount is included here for this calculation. In addition, operating leases were recorded on the Condensed Consolidated Balance Sheet as of January 1, 2019 and are included here for this calculation. See "Note 5 of the Notes to Condensed Consolidated Financial Statements" for further discussion.

Our shareholders’ equity increased $110.8 million during the first six months of 2019 primarily due to net income and the issuance of common stock, partially offset by dividends.

We need to finance capital expenditures and acquire additional funds for operations from time to time. The cash requirements needed to service our indebtedness, both short-term and long-term, reduce the amount of cash flow available to fund capital expenditures, purchased power, fuel and natural gas costs, dividends and other requirements.

Committed Lines of Credit

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million that expires in April 2021. As of June 30, 2019, there was $212.4 million of available liquidity under this line of credit.

The Avista Corp. credit facility contains customary covenants and default provisions, including 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, 2019, we were in compliance with this covenant with a ratio of 53.4 percent.

AEL&P has a $25.0 million committed line of credit that expires in November 2019. As of June 30, 2019, there were no borrowings or letters of credit 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, 2019, AEL&P was in compliance with this covenant with a ratio of 52.5 percent.

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

	2019	2018
Borrowings outstanding at end of period	$ 169,000	$ —
Letters of credit outstanding at end of period	$ 18,603	$ 25,620
Maximum borrowings outstanding during the period	$ 190,000	$ 111,000
Average borrowings outstanding during the period	$ 114,331	$ 48,442
Average interest rate on borrowings during the period	3.31%	2.37%
Average interest rate on borrowings at end of period	3.26%	—%

The increase in the average interest rates as of and for the six months ended June 30, 2019 was primarily the result of a downgrade in our credit rating by Moody's during December 2018. See the 2018 10-K for further discussion of the downgrade by Moody's.

As of June 30, 2019, 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.

Liquidity Expectations

In January 2019, we received a $103 million termination fee from Hydro One in connection with the termination of the proposed acquisition. The termination fee was used for reimbursing our transaction costs incurred from 2017 to 2019. These costs, including income taxes, total approximately $51 million. The balance of the termination fee was used for general corporate purposes and reduced our need for external financing.

During 2019, we expect to issue approximately $180.0 million of long-term debt and up to $65.0 million of equity (including issuances year-to-date) in order to refinance maturing long-term debt, fund planned capital expenditures and maintain an appropriate capital structure. This represents an increase from our previous estimates primarily to fund the expected increase in 2019 capital expenditures.

After considering the expected issuances of long-term debt and equity during 2019, we expect net cash flows from operating activities, together with cash available under our committed line of credit agreements, to provide adequate resources to fund capital expenditures, dividends, and other contractual commitments.

Capital Expenditures

We are making capital investments to enhance service and system reliability for our customers and replace aging infrastructure. We estimate capital expenditures at Avista Utilities will be approximately $435.0 million for 2019, which represents an increase from our previous estimate of $405.0 million. The increase is primarily related to increases in capital expenditures for renewable integration and customer growth. See the 2018 Form 10-K for further information on our expected capital expenditures.

Off-Balance Sheet Arrangements

As of June 30, 2019, we had $18.6 million in letters of credit outstanding under our $400.0 million committed line of credit, compared to $10.5 million as of December 31, 2018. The increase in letters of credit outstanding was due to additional letters of credit being issued as collateral for energy commodity derivative instruments.

Pension Plan

Avista Utilities

In the six months ended June 30, 2019 we contributed $14.6 million to the pension plan and we expect to contribute a total of $22.0 million in 2019. We expect to contribute a total of $110.0 million to the pension plan in the period 2019 through 2023, with annual contributions of $22.0 million over that period.

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

Contractual Obligations

Our future contractual obligations have not materially changed during the six months ended June 30, 2019. See the 2018 Form 10-K for our contractual obligations.

Environmental Issues and Contingencies

Our environmental issues and contingencies disclosures have not materially changed during the six months ended June 30, 2019 except for the following:

Colstrip Coal Contract

Colstrip, which is operated by Talen Montana, is supplied with fuel from adjacent coal reserves under coal supply and transportation agreements. The current contract for coal supply extends through 2019; however, the coal mine operator is in bankruptcy and had indicated that it would reject the current contract in its bankruptcy. The co-owners of Colstrip filed objections to the proposed rejection of the coal supply contract and in February 2019, an amended plan of reorganization was filed in which the proposal to reject the coal supply contract was withdrawn. The court approved the amended plan of reorganization on March 2, 2019, which allows the coal supply contract to remain in effect through 2019. The co-owners of Colstrip are in negotiations for an extension to the coal contract beyond 2019 and at the same time are exploring alternative sources for coal supply. Any new arrangements for coal beyond 2019 may have higher costs than the existing coal supply agreement.

Clean Energy Commitment

On April 18, 2019, we announced a goal to serve our customers with 100 percent clean electricity by 2045 and to have a carbon-neutral supply of electricity by the end of 2027. To help achieve these goals and add to our clean electricity portfolio, in the last three years, we have implemented three renewable energy projects on behalf of our customers, the Community Solar project (0.4 MW) in Spokane Valley, Washington (owned by Avista Corp.), the Solar Select project (28 MW) in Lind, Washington (PPA) and the Rattlesnake Flat Wind project (144 MW) in Adams County, Washington (PPA).

Climate Change - Federal Regulatory Actions

The EPA released the final version of the Affordable Clean Energy (ACE) rule, the replacement for the Clean Power Plan (CPP), in June 2019. EPA's final rule does not contain any final action on the proposed modifications to the new source review (NSR) program that would provide coal-fired power plants more latitude to make efficiency improvements without triggering pre-construction permit requirements. The final ACE rule combines three distinct EPA actions. First, EPA finalizes the repeal of the CPP.

Second, the EPA finalizes the ACE rule, which comprises EPA's determination of the Best System of Emissions Reduction (BSER) for existing coal-fired power plants and establishment of the procedures that will govern States' promulgation of standards of performance for existing EGUs within their borders. EPA sets the final BSER as heat rate efficiency improvements (HRI) based on a range of "candidate technologies" that can be applied inside the fence-line and requires that each State determine which apply to each coal-fired unit based on consideration of remaining useful plant life.

Lastly, EPA finalizes a number of changes to the implementing regulations for the timing of State plans for this and future section 111(d) rulemakings. With respect to the Colstrip Generation Station, the Montana Department of Environmental Protection (MDEQ) would initiate the BSER evaluation process. We cannot reasonably predict the timing or outcome of MDEQ's efforts, or estimate the extent to which Colstrip may be impacted at this time.

Climate Change - State Legislation and State Regulatory Activities

The states of Washington and Oregon have adopted non-binding targets to reduce GHG emissions. Both states enacted their targets with an expectation of reaching the targets through a combination of renewable energy standards, eventual carbon pricing mechanisms, such as cap and trade regulation or a carbon tax, and assorted "complementary policies." However, no specific reductions are mandated as yet. The Governors and Legislatures of both states began drafting climate-related proposals ahead of the 2019 legislative sessions. In Oregon, the State Senate failed to pass House Bill 2020 (HB 2020), authorizing the State to implement a cap and trade system and to link its allowances market with other jurisdictions. Had HB 2020 been enacted, Oregon would have been only the second state in the nation to implement an economy-wide cap and trade regulation. Avista monitored this legislation for its potential implications on the company's gas distribution operations in the state and upon the operation of its Coyote Springs II. In Washington State, Senate Bill 5116 (SB 5116) was the centerpiece of the Governor's package of legislation aiming to reduce greenhouse gas emissions from specific sectors of the economy through direct regulation. SB 5116 requires Washington utilities to no longer allocate coal-fired resources to Washington retail customers by the end of 2025, and to achieve carbon neutrality by 2030 while meeting a minimum 80 percent of load through delivery of renewable or non-emitting resources to customers. The legislation sets-forth alternative compliance measures that can be acquired by an electric utility to offset emissions from fossil fuel generation. The bill also requires utilities to meet 100 percent of load with renewable and non-emitting resources by 2045, although no penalties for failing to meet that standard were established. Under SB 5116, our hydroelectric and biomass generation facilities are considered resources that can be used to comply with the bill's clean energy standards. The bill was passed by both the Senate and House in April 2019 and was signed into law by the Governor on May 7, 2019. The law requires additional rulemaking by several Washington agencies for its measures to be enacted. We intend to seek recovery of any costs associated with the clean energy legislation through the regulatory process.

See the 2018 Form 10-K for further discussion of environmental issues and contingencies.

Enterprise Risk Management

The material risks to our businesses were discussed in our 2018 Form 10-K and have not materially changed during the six months ended June 30, 2019. Refer to the 2018 Form 10-K for further discussion of our risks and the mitigation of those risks.

Financial Risk

Our financial risks have not materially changed during the six months ended June 30, 2019. Refer to the 2018 Form 10-K. The financial risks included below are required interim disclosures, even if they have not materially changed from December 31, 2018.

Interest Rate Risk

We use a variety of techniques to manage our interest rate risks. We have an interest rate risk policy and have established 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 6 of the Notes to Condensed Consolidated Financial Statements" for a summary of our interest rate swap derivatives outstanding as of June 30, 2019 and December 31, 2018 and the amount of additional collateral we would have to post in certain circumstances. In addition, see "Regulatory Matters" for a discussion of commitments we made in Oregon surrounding the independent review of our interest rate hedging practices.

Credit Risk

Avista Utilities' contracts for the purchase and sale of energy commodities can require collateral in the form of cash or letters of credit. As of June 30, 2019, we had cash deposited as collateral in the amount of $26.2 million and letters of credit of $14.6 million outstanding related to our energy derivative contracts. Price movements and/or a downgrade in our credit ratings could impact further the amount of collateral required. See “Credit Ratings” in the 2018 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, 2019 (including contracts that are considered derivatives and those that are considered non-derivatives), we would potentially be required to post the following additional collateral (in thousands):

	June 30, 2019
Additional collateral taking into account contractual thresholds	$ 5,500
Additional collateral without contractual thresholds	6,700

Under the terms of interest rate swap derivatives that we enter into periodically, we may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the instrument. As of June 30, 2019, we had interest rate swap derivatives outstanding with a notional amount totaling $265.0 million and we had deposited cash in the amount of $5.0 million as collateral 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, 2019, we would potentially be required to post the following additional collateral (in thousands):

	June 30, 2019
Additional collateral taking into account contractual thresholds	$ 7,500
Additional collateral without contractual thresholds	26,000

Energy Commodity Risk

Our energy commodity risks have not materially changed during the six months ended June 30, 2019, except as discussed below. Refer to the 2018 Form 10-K. The following table presents energy commodity derivative fair values as a net asset or (liability) as of June 30, 2019 that are expected to settle in each respective year (dollars in thousands):

	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 2019	$ 12	$ 3,894	$ (869)	$ (7,602)	$ (127)	$ (16,161)	$ (623)	$ (158)
2020	—	—	(837)	(2,161)	(274)	(6,164)	(1,565)	(1,313)
2021	—	—	—	212	—	(989)	(810)	(399)
2022	—	—	—	44	—	—	—	—
2023	—	—	—	—	—	—	—	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2018 that are expected to be delivered in each respective year (dollars in thousands):

	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)
2019	$ (2,238)	$ 7,289	$ (991)	$ (32,285)	$ 34	$ (19,047)	$ (443)	$ 6,252
2020	—	—	(1,266)	(7,797)	(28)	(4,044)	(1,517)	(240)
2021	—	—	—	(1,393)	—	—	(629)	47
2022	—	—	—	—	—	—		—
2023	—	—	—	—	—	—	—	—
Thereafter	—	—	—	—	—	—	—	—

(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 the various 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.

Regional Energy Markets

The California Independent System Operator (CAISO) operates an Energy Imbalance Market (EIM) in the western United States. Most investor-owned utilities in the Pacific Northwest are either participants in the CAISO EIM or plan to integrate into the market in the near future. Factors to be considered in deciding whether to join the CAISO EIM include the amount of variable generating resources in the utilities' systems, the ability to manage the variable generating resources within the utilities' systems, the costs associated with joining the CAISO EIM, and the economic benefits associated with joining the CAISO EIM. As additional utilities join the CAISO EIM, there is a reduction in bilateral market liquidity and opportunities for wholesale transactions close to the operating hour. Based on these considerations, we signed an agreement in April 2019 to join the CAISO EIM. We expect to begin implementing new processes to enable participation in the EIM in the second half of 2019 and we expect to be full participants by April 2022. We estimate the total cost of joining the EIM to be approximately $25 million for both capital and operating expense spending over the three-year implementation period and we estimate annual benefits of approximately $6 million from market participation. We expect to seek recovery of the net costs through the regulatory process.

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, 2019.

There have been no changes in the Company's internal control over financial reporting that occurred during the second quarter of 2019 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 2018 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 2018 Form 10-K.

In addition to these risk factors, see also “Forward-Looking Statements” for additional factors which could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

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	XBRL Instance Document. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

(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, 2019

/s/ Mark T. Thies
Mark T. Thies
Senior Vice President,
Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Exhibit 15

August 6, 2019

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

We have reviewed, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the unaudited interim financial information of Avista Corporation and subsidiaries for the periods ended June 30, 2019 and 2018, as indicated in our report dated August 6, 2019; because we did not perform an audit, we expressed no opinion on that information.

We are aware that our report referred to above, which is included in your Quarterly Report on Form 10-Q for the quarter ended March 31, 2019, is incorporated by reference in Registration Statement Nos. 333-33790, 333-126577, 333-179042 and 333-208986 on Form S-8 and in Registration Statement No. 333-231431 on Form S-3.

We also are aware that the aforementioned report, pursuant to Rule 436(c) under the Securities Act of 1933, is not considered a part of the Registration Statements prepared or certified by an accountant or a report prepared or certified by an accountant within the meaning of Sections 7 and 11 of that Act.

/s/ Deloitte & Touche LLP

Seattle, Washington

Exhibit 31.1

CERTIFICATION

I, Scott L. Morris, 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, 2019

/s/ Scott L. Morris

Scott L. Morris
Chairman of the Board
and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Mark T. Thies, 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, 2019

/s/ Mark T. Thies

Mark T. Thies
Senior Vice President,
Chief Financial Officer, and Treasurer
(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, Scott L. Morris, Chairman of the Board and Chief Executive Officer of Avista Corporation (the “Company”), and Mark T. Thies, Senior Vice President, Chief Financial Officer and Treasurer 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, 2019 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, 2019

/s/ Scott L. Morris

Scott L. Morris
Chairman of the Board
and Chief Executive Officer

/s/ Mark T. Thies

Mark T. Thies
Senior Vice President,
Chief Financial Officer, and Treasurer