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

Form 10-Q

(Mark One)

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

FOR THE QUARTERLY PERIOD ENDED September 30, 2018 OR

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

FOR THE TRANSITION PERIOD FROM TO

Commission file number 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)	**(Zip Code)**

Registrant's telephone number, including area code: 509-489-0500
Web site: http://www.avistacorp.com

None

(Former name, former address and former fiscal year, if changed since last report)

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 x No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 x 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	x	Accelerated filer	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	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 x

As of October 31, 2018, 65,688,000 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
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
ARAM	-	Average Rate Assumption Method
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 Energy	-	Avista Energy, Inc., an inactive electricity and natural gas marketing, trading and resource management business, subsidiary of Avista Capital
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
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
Ecology	-	The state of Washington’s Department of Ecology
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
GAAP	-	Generally Accepted Accounting Principles
GHG	-	Greenhouse gas
Hydro One	-	Hydro One Limited, based in Toronto, Ontario, Canada
IPUC	-	Idaho Public Utilities Commission
IRP	-	Integrated Resource Plan
Juneau	-	The City and Borough of Juneau, Alaska
MPSC	-	Public Service Commission of the State of Montana
MW, MWh	-	Megawatt: 1000 KW. Megawatt-hour: 1000 KWh
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
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 for electricity; 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 and other capital market conditions and the global economy;
- 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 global climate and the long-term climate within our utilities' service areas, which can affect, among other things, customer demand patterns and the volume and timing of streamflows to our hydroelectric resources;

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 and discretion over allowed return on investment;

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 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, cyber attacks 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, cyber attacks 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 operations 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

- compliance with extensive federal, state and local legislation and regulation, including numerous environmental, health, safety, infrastructure protection, reliability and other laws and regulations that affect our operations and costs;
- the ability to comply with the terms of the licenses and permits for our hydroelectric or thermal generating facilities at cost-effective levels;

Technology Risk

- cyber attacks on us or our vendors or other potential lapses that result in unauthorized disclosure of private information, which could result in liabilities against us, costs to investigate, remediate and defend, and damage to our reputation;
- disruption to or breakdowns of information systems, automated controls and other technologies that we rely on for our operations, communications and customer service;
- 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;
- failure to complete the proposed acquisition of the Company by Hydro One, which would negatively impact the market price of Avista Corp.'s common stock and could result in termination fees that would have a material adverse effect on our results of operations, financial condition, and cash flows;

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 which are detrimental or beneficial to our overall business;
- the Tax Cuts and Jobs Act and its intended and unintended consequences on financial results and future cash flows, including the potential impact to credit ratings, which may affect our ability to borrow funds or increase the cost of borrowing in the future;
- 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.avistacorp.com. We make annual, quarterly and current reports available on our website as soon as practicable after electronically filing these reports with the SEC. Information contained on our website 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 Nine Months Ended September 30
Dollars in thousands, except per share amounts
(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Operating Revenues:				
Utility revenues:				
Utility revenues, exclusive of alternative revenue programs	$ 288,513	$ 296,375	$ 1,006,003	$ 1,046,352
Alternative revenue programs	606	(4,735)	(1,763)	(15,446)
Total utility revenues	289,119	291,640	1,004,240	1,030,906
Non-utility revenues	6,894	5,456	20,432	17,161
Total operating revenues	296,013	297,096	1,024,672	1,048,067
Operating Expenses:				
Utility operating expenses:				
Resource costs	101,519	108,568	362,106	376,905
Other operating expenses	78,395	75,927	236,771	227,212
Acquisition costs	965	6,730	2,620	8,004
Depreciation and amortization	46,035	42,968	136,419	127,596
Taxes other than income taxes	25,101	23,269	81,526	79,733
Non-utility operating expenses:				
Other operating expenses	7,347	6,598	20,714	19,863
Depreciation and amortization	207	137	587	482
Total operating expenses	259,569	264,197	840,743	839,795
Income from operations	36,444	32,899	183,929	208,272
Interest expense	24,280	23,955	74,226	71,170
Interest expense to affiliated trusts	325	216	880	601
Capitalized interest	(1,217)	(899)	(3,324)	(2,513)
Other expense (income)-net	1,379	16	3,951	(851)
Income before income taxes	11,677	9,611	108,196	139,865
Income tax expense	1,548	5,153	17,467	51,548
Net income	10,129	4,458	90,729	88,317
Net loss (income) attributable to noncontrolling interests	(10)	(7)	(143)	21
Net income attributable to Avista Corp. shareholders	$ 10,119	$ 4,451	$ 90,586	$ 88,338
Weighted-average common shares outstanding (thousands), basic	65,688	64,412	65,668	64,392
Weighted-average common shares outstanding (thousands), diluted	66,026	64,892	65,980	64,638
Earnings per common share attributable to Avista Corp. shareholders:				
Basic	$ 0.15	$ 0.07	$ 1.38	$ 1.37
Diluted	$ 0.15	$ 0.07	$ 1.37	$ 1.37
Dividends declared per common share	$ 0.3725	$ 0.3575	$ 1.1175	$ 1.0725

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

For the Three and Nine Months Ended September 30
Dollars in thousands
(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Net income	$ 10,129	$ 4,458	$ 90,729	$ 88,317
Other Comprehensive Income:				
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $54, $98, $163 and $295 respectively	204	182	612	548
Total other comprehensive income	204	182	612	548
Comprehensive income	10,333	4,640	91,341	88,865
Comprehensive loss (income) attributable to noncontrolling interests	(10)	(7)	(143)	21
Comprehensive income attributable to Avista Corporation shareholders	$ 10,323	$ 4,633	$ 91,198	$ 88,886

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands
(Unaudited)

	September 30, 2018	December 31, 2017
Assets:		
Current Assets:		
Cash and cash equivalents	$ 21,170	$ 16,172
Accounts and notes receivable-less allowances of $5,705 and $5,132, respectively	104,892	185,664
Materials and supplies, fuel stock and stored natural gas	62,766	58,075
Regulatory assets	21,525	44,750
Other current assets	35,159	32,873
Total current assets	245,512	337,534
Net utility property	4,555,440	4,398,810
Goodwill	57,672	57,672
Non-current regulatory assets	576,863	619,399
Other property and investments-net and other non-current assets	121,911	101,317
Total assets	$ 5,557,398	$ 5,514,732
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 80,892	$ 107,289
Current portion of long-term debt and capital leases	2,629	277,438
Short-term borrowings	35,000	105,398
Regulatory liabilities	94,978	48,264
Other current liabilities	133,404	159,113
Total current liabilities	346,903	697,502
Long-term debt and capital leases	1,860,944	1,491,799
Long-term debt to affiliated trusts	51,547	51,547
Pensions and other postretirement benefits	191,021	203,566
Deferred income taxes	488,767	466,630
Non-current regulatory liabilities	798,440	800,089
Other non-current liabilities and deferred credits	69,425	73,115
Total liabilities	3,807,047	3,784,248
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; 65,688,000 and 65,494,333 shares issued and outstanding, respectively	1,135,543	1,133,448
Accumulated other comprehensive loss	(9,220)	(8,090)
Retained earnings	623,229	604,470
Total Avista Corporation shareholders' equity	1,749,552	1,729,828
Noncontrolling Interests	799	656
Total equity	1,750,351	1,730,484
Total liabilities and equity	$ 5,557,398	$ 5,514,732

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

For the Nine Months Ended September 30
Dollars in thousands
(Unaudited)

	2018	2017
Operating Activities:		
Net income	$ 90,729	$ 88,317
Non-cash items included in net income:		
Depreciation and amortization	139,738	130,803
Deferred income tax provision and investment tax credits	10,575	58,242
Power and natural gas cost amortizations, net	6,315	8,416
Amortization of debt expense	2,327	2,440
Amortization of investment in exchange power	1,838	1,838
Stock-based compensation expense	5,215	5,809
Equity-related AFUDC	(4,406)	(5,012)
Pension and other postretirement benefit expense	23,980	27,816
Other regulatory assets and liabilities and deferred debits and credits	20,953	(12,683)
Change in decoupling regulatory deferral	5,436	20,193
Other	3,962	(190)
Contributions to defined benefit pension plan	(22,000)	(22,000)
Cash paid for settlement of interest rate swap agreements	(32,174)	(11,302)
Cash received for settlement of interest rate swap agreements	5,594	2,479
Changes in certain current assets and liabilities:		
Accounts and notes receivable	75,878	52,534
Materials and supplies, fuel stock and stored natural gas	(4,691)	(12,653)
Collateral posted for derivative instruments	47,150	(1,896)
Income taxes receivable	(5,994)	(4,254)
Other current assets	2,123	(16)
Accounts payable	(16,392)	(29,992)
Other current liabilities	9,639	8,624
Net cash provided by operating activities	365,795	307,513
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(296,216)	(287,853)
Issuance of notes receivable at subsidiaries	(2,930)	(2,800)
Equity and property investments made by subsidiaries	(8,629)	(10,899)
Distributions from investments	1,946	1,915
Other	(1,858)	(2,714)
Net cash used in investing activities	(307,687)	(302,351)

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

For the Nine Months Ended September 30
Dollars in thousands
(Unaudited)

	2018	2017
Financing Activities:		
Net increase (decrease) in short-term borrowings	$ (70,398)	$ 75,000
Proceeds from issuance of long-term debt	374,621	—
Maturity of long-term debt and capital leases	(276,804)	(2,465)
Issuance of common stock, net of issuance costs	1,224	1,490
Cash dividends paid	(73,569)	(69,220)
Other	(8,184)	(3,758)
Net cash provided by (used in) financing activities	(53,110)	1,047
Net increase in cash and cash equivalents	4,998	6,209
Cash and cash equivalents at beginning of period	16,172	8,507
Cash and cash equivalents at end of period	$ 21,170	$ 14,716

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

Avista Corporation

For the Nine Months Ended September 30
Dollars in thousands
(Unaudited)

	2018	2017
Common Stock, Shares:		
Shares outstanding at beginning of period	65,494,333	64,187,934
Shares issued	193,667	226,638
Shares outstanding at end of period	65,688,000	64,414,572
Common Stock, Amount:		
Balance at beginning of period	$ 1,133,448	$ 1,075,281
Equity compensation expense	4,800	5,055
Issuance of common stock, net of issuance costs	1,224	1,490
Payment of minimum tax withholdings for share-based payment awards	(3,929)	(3,420)
Purchase of subsidiary noncontrolling interests	—	(1,191)
Balance at end of period	1,135,543	1,077,215
Accumulated Other Comprehensive Loss:		
Balance at beginning of period	(8,090)	(7,568)
Other comprehensive income	612	548
Reclassification of excess income tax benefits	(1,742)	—
Balance at end of period	(9,220)	(7,020)
Retained Earnings:		
Balance at beginning of period	604,470	581,014
Net income attributable to Avista Corporation shareholders	90,586	88,338
Cash dividends paid on common stock	(73,569)	(69,220)
Reclassification of excess income tax benefits	1,742	—
Balance at end of period	623,229	600,132
Total Avista Corporation shareholders' equity	1,749,552	1,670,327
Noncontrolling Interests:		
Balance at beginning of period	656	(251)
Net income (loss) attributable to noncontrolling interests	143	(21)
Purchase of subsidiary noncontrolling interests	—	891
Balance at end of period	799	619
Total equity	$ 1,750,351	$ 1,670,946

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 September 30, 2018 and September 30, 2017 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, 2017 (2017 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 Avista Utilities' 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.

On July 19, 2017, Avista Corp. entered into an Agreement and Plan of Merger (Merger Agreement) to become a wholly-owned subsidiary of Hydro One. Consummation of the pending acquisition is subject to a number of approvals and the satisfaction or waiver of other specified conditions. The transaction is expected to close during the fourth quarter of 2018. See Note 17 for additional information.

Basis of Reporting

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

Certain line items are presented in a more condensed form on the Condensed Consolidated Balance Sheets as of September 30, 2018 than in prior periods. The prior year amounts were reclassified to conform to the current year presentation. The primary classification changes were related to classifying all current regulatory assets, current regulatory liabilities, non-current regulatory assets and non-current regulatory liabilities into their own line items. Previously, these items were either on many separate line items or embedded in other line items such as "Other property and investments-net and other non-current assets" or "Other non-current liabilities, regulatory liabilities and deferred credits." See Note 3 for a summary of the items contained in certain balance sheet accounts.

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 purchased gas cost adjustments, 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 September 30, 2018, 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. 2014-09, “Revenue from Contracts with Customers (Topic 606)”

On January 1, 2018, the Company adopted ASU No. 2014-09, which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance.

The Company elected to use a modified retrospective method of adoption, which required a cumulative adjustment to opening retained earnings (if any were identified), as opposed to a full retrospective application. The Company did not identify any adjustments required to opening retained earnings related to the adoption of the new revenue standard. The Company applied the retrospective application only to contracts that were not completed as of the implementation date. The Company did not apply the new guidance to contracts that were completed with all revenue recognized prior to the implementation date. In addition, total operating revenues on the Condensed Consolidated Statements of Income in years prior to 2018 would not have changed if the Company had elected to apply the full retrospective method of adoption.

Since the majority of Avista Corp.’s revenue is from rate-regulated sales of electricity and natural gas to retail customers and revenue is recognized as energy is delivered to these customers, the Company does not expect any significant change in operating revenues or net income going forward.

The only changes in revenue that resulted from the adoption of this ASU were related to the presentation of utility-related taxes collected from customers and the timing of when revenue from self-generated RECs is recognized.

Under ASU No. 2014-09, revenue associated with the sale of RECs is recognized at the time of generation and sale of the credits as opposed to when the RECs are certified in the Western Renewable Energy Generation Information System, which generally occurs during a period subsequent to the sale. This represents a change from the Company's prior practice, which was to defer revenue recognition until the time of certification. Revenue associated with the sale of RECs is not material to the financial statements and almost all of the Company's REC revenue is deferred for future rebate to retail customers. As such, the change in the timing of revenue recognition does not have a material impact on net income.

See Note 4 for the Company's complete revenue disclosures.

ASU No. 2016-02 "Leases (Topic 842)"

In February 2016, the FASB issued ASU No. 2016-02. This ASU introduces a new lessee model that requires most leases to be capitalized and shown on the balance sheet with corresponding lease assets and liabilities. The standard also aligns certain of the underlying principles of the new lessor model with those in Topic 606, the FASB's new revenue recognition standard. Furthermore, this ASU addresses other issues that arise under the current lease model; for example, eliminating the required use of bright-line tests in current GAAP for determining lease classification (operating leases versus capital leases). This ASU also includes enhanced disclosures surrounding leases. This ASU is effective for periods beginning on or after December 15, 2018; however, early adoption is permitted. Under ASU No. 2016-02, upon adoption, the effects of this standard must be applied using a modified retrospective approach to the earliest period presented. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. In July 2018, the FASB issued ASU No. 2018-11 which provides a practical expedient that allows companies to use an optional transition method. Under the optional transition method, a cumulative adjustment to retained earnings during the period of adoption is recorded and prior periods would not require restatement.

The Company evaluated ASU No. 2016-02 and determined that it will not early adopt this standard before its effective date in 2019. Upon adoption, the Company expects to elect a package of practical expedients that will allow it to not reassess whether any expired or existing contract is a lease or contains a lease, the lease classification of any expired or existing leases, and the initial direct costs for any existing leases.

The Company formed a lease standard implementation team that is working through the implementation process. Based on work to date, the implementation team identified a complete population of existing and potential leases under the new standard and completed its review of the agreements associated with this population. The Company has not yet fully quantified the estimated financial statement impact, but based on the Company's preliminary conclusions, the Company does not expect any material impacts to its future financial condition, results of operations and cash flows, other than the recognition of the right-of-use asset and lease liability on the Condensed Consolidated Balance Sheet.

The Company is monitoring utility industry implementation guidance as it relates to several unresolved issues to determine if there will be an industry consensus.

ASU No. 2017-07 "Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost"

On January 1, 2018, the Company adopted ASU No. 2017-07, which amended the income statement presentation of the components of net period benefit cost for an entity's defined benefit pension and other postretirement plans. Under previous GAAP, net benefit cost consisted of several components that reflected different aspects of an employer's financial arrangements as well as the cost of benefits earned by employees. These components were aggregated and reported net in the financial statements. ASU No. 2017-07 requires entities to (1) disaggregate the current service-cost component from the other components of net benefit cost (other components) and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations.

In addition, only the service-cost component of net benefit cost is eligible for capitalization (e.g., as part of utility plant). This is a change from prior practice, under which entities capitalized the aggregate net benefit cost to utility plant when applicable, in accordance with FERC accounting guidance. Avista Corp. is a rate-regulated entity and all components of net benefit cost are currently recovered from customers as a component of utility plant and, under the new ASU, these costs will continue to be recovered from customers in the same manner over the depreciable lives of utility plant. As all such costs are expected to continue to be recoverable, the components that are no longer eligible to be recorded as a component of utility plant for GAAP will be recorded as regulatory assets.

Upon adoption, entities must use a retrospective transition method to adopt the requirement for separate presentation in the income statement and a prospective transition method to adopt the requirement to limit the capitalization of benefit costs to the service-cost component. Due to the retrospective requirements for income statement presentation, for the three and nine months ended September 30, 2017, the Company reclassified $1.9 million and $5.7 million, respectively in non-service cost components of pension and other postretirement benefits from utility other operating expenses to other expense (income)-net on the Condensed Consolidated Statements of Income. See Note 6 for additional discussion regarding pension and other postretirement benefit expense.

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 is effective for periods beginning after December 15, 2018 and early adoption is 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 nine months ended September 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 September 30, 2018.

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 September 30, 2018.

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 September 30, 2018 and December 31, 2017 (dollars in thousands):

	September 30, 2018	December 31, 2017
Materials and supplies	$ 45,169	$ 41,493
Fuel stock	5,347	4,843
Stored natural gas	12,250	11,739
Total	$ 62,766	$ 58,075

Net Utility Property

Net utility property consisted of the following as of September 30, 2018 and December 31, 2017 (dollars in thousands):

	September 30, 2018	December 31, 2017
Utility plant in service	$ 6,060,373	$ 5,853,308
Construction work in progress	180,237	157,839
Total	6,240,610	6,011,147
Less: Accumulated depreciation and amortization	1,685,170	1,612,337
Total net utility property	$ 4,555,440	$ 4,398,810

Other Current Liabilities

Other current liabilities consisted of the following as of September 30, 2018 and December 31, 2017 (dollars in thousands):

	September 30, 2018	December 31, 2017
Accrued taxes other than income taxes	$ 37,723	$ 33,802
Current unsettled interest rate swap derivative liabilities	—	34,447
Employee paid time off accruals	20,644	20,330
Accrued interest	30,343	16,351
Current portion of pensions and other postretirement benefits	10,036	11,544
Utility energy commodity derivative liabilities	6,853	8,848
Other current liabilities	27,805	33,791
Total other current liabilities	$ 133,404	$ 159,113

Regulatory Assets and Liabilities

Regulatory assets and liabilities consisted of the following as of September 30, 2018 and December 31, 2017 (dollars in thousands):

	September 30, 2018		December 31, 2017	
	Current	Non-Current	Current	Non-Current
Regulatory Assets				
Energy commodity derivatives	$ 19,238	$ 9,555	$ 24,991	$ 18,967
Decoupling surcharge	2,287	18,099	19,759	2,600
Pension and other postretirement benefit plans	—	201,620	—	209,115
Interest rate swaps	—	131,972	—	169,704
Deferred income taxes	—	90,285	—	90,315
Settlement with Coeur d'Alene Tribe	—	42,971	—	43,954
Demand side management programs	—	19,774	—	24,620
Utility plant to be abandoned	—	24,158	—	24,330
Other regulatory assets	—	38,429	—	35,794
Total regulatory assets	$ 21,525	$ 576,863	$ 44,750	$ 619,399

	September 30, 2018		December 31, 2017	
	Current	Non-Current	Current	Non-Current
Regulatory Liabilities				
Income tax related liabilities	$ 36,850	$ 433,714	$ —	$ 460,542
Deferred natural gas costs	35,442	—	37,474	—
Deferral power costs	9,792	30,219	5,816	24,057
Decoupling rebate	8,853	426	—	5,816
Utility plant retirement costs	—	293,965	—	285,786
Interest rate swaps	—	36,345	—	18,638
Other regulatory liabilities	4,041	3,771	4,974	5,250
Total regulatory liabilities	$ 94,978	$ 798,440	$ 48,264	$ 800,089

NOTE 4. REVENUE

ASC 606, which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and superseded previous revenue recognition guidance, including industry-specific guidance, became effective on January 1, 2018. The core principle of the revenue 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.

In addition, the sale of electricity and natural gas is governed by the various state utility commissions, which set rates, charges, terms and conditions of service, and prices. Collectively, these rates, charges, terms and conditions are included in a "tariff," which governs all aspects of the provision of regulated services. Tariffs are only permitted to be changed through a rate-setting process involving an independent, third-party regulator empowered by statute to establish rates that bind customers. Thus, all regulated sales by the Company are conducted subject to the regulator-approved tariff.

Tariff sales involve the current provision of commodity service (electricity and/or natural gas) to customers for a price that generally has a basic charge and a usage-based component. Tariff rates also include certain pass-through costs to customers such as natural gas costs, retail revenue credits and other miscellaneous regulatory items that do not impact net income, but can cause total revenue to fluctuate significantly up or down compared to previous periods. The commodity is sold and/or delivered to and consumed by the customer simultaneously, and the provisions of the relevant tariff determine the charges the Company may bill the customer, payment due date, and other pertinent rights and obligations of both parties. Generally, tariff sales do not involve a written contract. 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."

Unbilled Revenue from Contracts with Customers

The determination of the volume of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month (once per month for each individual customer). At the end of each calendar month, the amount of energy delivered to customers since the date of the last meter reading is estimated and the corresponding unbilled revenue is estimated and recorded. The Company's estimate of unbilled revenue is based on:

- the number of customers,
- current rates,

- meter reading dates,
- actual native load for electricity,
- actual throughput for natural gas, and
- electric line losses and natural gas system losses.

Any difference between actual and estimated revenue is automatically corrected in the following month when the actual meter reading and customer billing occurs.

Accounts receivable includes unbilled energy revenues of the following amounts as of September 30, 2018 and December 31, 2017 (dollars in thousands):

	September 30, 2018	December 31, 2017
Unbilled accounts receivable	$ 38,991	$ 68,641

Non-Derivative Wholesale Contracts

The Company has certain wholesale contracts which do not meet the criteria for classification as derivatives. Since they do not meet the definition of a derivative, they are within the scope of ASC 606 and are considered revenue from contracts with customers. Revenue is recognized as energy is delivered to the customer or the service is available for specified period of time, consistent with the discussion of tariff 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 which 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 which 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.

Two acceptable methods of presenting decoupling revenue have evolved within the utility industry and a policy election is required by the Company. The two options relate to how the collection/refund of previously recognized decoupling revenue is presented within total revenue. The first option is the gross method, which is to amortize the decoupling regulatory asset/liability to the alternative revenue program line item on the Condensed Consolidated Statement of Income as it is collected from or refunded to customers. The cash passing between the Company and the customers is presented in revenue from contracts with customers since it is a portion of the overall tariff paid by customers. This method results in a gross-up to both revenue from contracts with customers and revenue from alternative revenue programs, but has a net zero impact on total revenue. The second option is the net method, which requires the amortization of the decoupling regulatory asset/liability to be presented within revenue from contracts with customers such that, when netted against the cash passing between the Company and the customers within the same line item, there is a net zero impact to revenue from contracts with customers and total revenue. The Company has elected the gross method for the presentation of alternative revenue program revenue, consistent with historical practice. Depending on whether the previous deferral balance being amortized was a regulatory asset or regulatory liability, and depending on the size and direction of the current year deferral of surcharges and/or rebates to customers, it could result in negative alternative revenue program revenue during the year.

Derivative Revenue

Most wholesale electric and natural gas transactions (including both physical and financial transactions), and the sale of fuel are considered derivatives, which are 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 which 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, enacted in December 2017. 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

Contracts with Multiple Performance Obligations

In addition to the tariff sales described above, which are stand-alone energy sales, the Company has bundled arrangements which contain multiple performance obligations including some combination of energy, capacity, energy reserves and RECs. Under these arrangements, the total contract price is allocated to the various performance obligations and revenue is recognized as the obligations are satisfied. Depending on the source of the revenue, it could either be included in revenue from contracts with customers or derivative revenue.

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, effective January 1, 2018, these transactions at AEL&P are presented on a net basis within revenue from contracts with customers. Prior to the adoption of ASU No. 2014-09, the Company presented utility-related taxes at AEL&P on a gross basis, consistent with the presentation for Avista Utilities. In prior years, there were approximately $2.0 million annually in utility-related taxes collected from customers included in revenue for AEL&P.

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

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Utility-related taxes	$ 12,294	$ 12,663	$ 44,447	$ 47,799

Non-Utility Revenues

Revenue from Contracts with Customers

Non-utility revenues from contracts with customers are primarily derived from the operations of METALfx. 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.

Other Revenue

Other non-utility revenue primarily relates to rent revenue, which is scoped out of ASC 606; therefore, this revenue is presented separately from revenue from contracts with customers.

Significant Judgments and Unsatisfied Performance Obligations

The vast majority of the Company's revenues are derived from the rate-regulated sale of electricity and natural gas that have two performance obligations that are satisfied throughout the period and as energy is delivered to customers. In addition, the customers do not pay for energy in advance of receiving it. As such, the Company does not have any significant unsatisfied performance obligations or deferred revenues as of period-end associated with these revenues. Also, the only significant judgments involving revenue recognition are estimates surrounding unbilled revenue and receivables from contracts with customers (discussed in detail above) and estimates surrounding the amount of decoupling revenues which will be collected from customers within 24 months.

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 September 30, 2018, the Company estimates it had unsatisfied capacity performance obligations of $11.4 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 nine months ended September 30 (dollars in thousands):

	Three months ended September 30, 2018	Nine months ended September 30, 2018
Avista Utilities		
Revenue from contracts with customers	$ 242,098	$ 835,373
Derivative revenues	32,718	147,467
Alternative revenue programs	606	(1,763)
Deferrals and amortizations for rate refunds to customers	1,940	(16,900)
Other utility revenues	2,187	6,348
Total Avista Utilities	279,549	970,525
AEL&P		
Revenue from contracts with customers	9,599	35,008
Deferrals and amortizations for rate refunds to customers	(156)	(1,705)
Other utility revenues	127	412
Total AEL&P	9,570	33,715
Other		
Revenue from contracts with customers	6,580	19,633
Other revenues	314	799
Total other	6,894	20,432
Total operating revenues	$ 296,013	$ 1,024,672

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 nine months ended September 30 (dollars in thousands):

	Three months ended September 30, 2018			Nine months ended September 30, 2018		
	Avista Utilities	AEL&P	Total Utility	Avista Utilities	AEL&P	Total Utility
ELECTRIC OPERATIONS						
Revenue from contracts with customers						
Residential	$ 82,470	$ 2,987	$ 85,457	$ 272,041	$ 13,680	$ 285,721
Commercial and governmental	80,744	6,546	87,290	236,115	21,131	257,246
Industrial	30,806	—	30,806	83,910	—	83,910
Public street and highway lighting	1,860	66	1,926	5,618	197	5,815
Total retail revenue	195,880	9,599	205,479	597,684	35,008	632,692
Transmission	4,832	—	4,832	12,833	—	12,833
Other revenue from contracts with customers	8,564	—	8,564	18,774	—	18,774
Total revenue from contracts with customers	$ 209,276	$ 9,599	$ 218,875	$ 629,291	$ 35,008	$ 664,299

	Three months ended September 30, 2018			Nine months ended September 30, 2018		
	Avista Utilities	AEL&P	Total Utility	Avista Utilities	AEL&P	Total Utility
NATURAL GAS OPERATIONS						
Revenue from contracts with customers						
Residential	$ 19,247	$ —	$ 19,247	$ 130,668	$ —	$ 130,668
Commercial	9,437	—	9,437	61,477	—	61,477
Industrial and interruptible	1,006	—	1,006	3,767	—	3,767
Total retail revenue	29,690	—	29,690	195,912	—	195,912
Transportation	2,007	—	2,007	6,795	—	6,795
Other revenue from contracts with customers	1,125	—	1,125	3,375	—	3,375
Total revenue from contracts with customers	$ 32,822	$ —	$ 32,822	$ 206,082	$ —	$ 206,082

NOTE 5. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, swap derivatives and options 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 September 30, 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
Remainder 2018	120	542	8,109	34,905	41	575	3,101	20,683
2019	204	901	5,110	87,118	123	2,403	2,245	47,488
2020	—	—	910	31,005	—	836	1,430	7,995
2021	—	—	—	4,975	—	—	1,049	2,275
2022	—	—	—	—	—	—	—	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents the underlying energy commodity derivative volumes as of December 31, 2017 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
2018	426	763	10,572	107,580	213	1,739	3,643	67,375
2019	235	737	610	61,073	94	1,420	1,345	35,438
2020	—	—	910	16,590	—	589	1,430	915
2021	—	—	—	—	—	—	1,049	—
2022	—	—	—	—	—	—	—	—
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 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 September 30, 2018 and December 31, 2017 (dollars in thousands):

	September 30, 2018	December 31, 2017
Number of contracts	18	18
Notional amount (in United States dollars)	$ 3,255	$ 2,552
Notional amount (in Canadian dollars)	4,236	3,241

Interest Rate 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 September 30, 2018 and December 31, 2017 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
September 30, 2018	6	$ 70,000	2019
	4	40,000	2020
	1	15,000	2021
	6	70,000	2022
December 31, 2017	14	$ 275,000	2018
	6	70,000	2019
	3	30,000	2020
	1	15,000	2021
	5	60,000	2022

During the second quarter 2018, in connection with the issuance and sale of $375.0 million of Avista Corp. first mortgage bonds (see Note 9), the Company cash-settled fourteen interest rate swap derivatives (notional aggregate amount of $275.0 million) and paid a net amount of $26.6 million. 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 September 30, 2018 and December 31, 2017 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 September 30, 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 assets	$ 26	$ —	$ —	$ 26
Interest rate swap derivatives				
Other property and investments-net and other non-current assets	18,029	—	—	18,029
Other non-current liabilities and deferred credits	129	(4,577)	—	(4,448)
Energy commodity derivatives				
Other current assets	904	(27)	—	877
Other property and investments-net and other non-current assets	7	—	—	7
Other current liabilities	29,992	(50,107)	13,262	(6,853)
Other non-current liabilities and deferred credits	6,854	(16,416)	6,087	(3,475)
Total derivative instruments recorded on the balance sheet	$ 55,941	$ (71,127)	$ 19,349	$ 4,163

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of December 31, 2017 (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	$ 32	$ (1)	$ —	$ 31
Interest rate swap derivatives				
Other current assets	2,597	(270)	—	2,327
Other property and investments-net and other non-current assets	4,880	(2,304)	—	2,576
Other current liabilities	—	(63,399)	28,952	(34,447)
Other non-current liabilities and deferred credits	—	(7,540)	6,018	(1,522)
Energy commodity derivatives				
Other current assets	1,386	(122)	—	1,264
Other current liabilities	26,641	(52,895)	17,406	(8,848)
Other non-current liabilities and deferred credits	15,970	(34,936)	10,032	(8,934)
Total derivative instruments recorded on the balance sheet	$ 51,506	$ (161,467)	$ 62,408	$ (47,553)

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 September 30, 2018 and December 31, 2017 (in thousands):

	September 30, 2018	December 31, 2017
Energy commodity derivatives		
Cash collateral posted	$ 27,277	$ 39,458
Letters of credit outstanding	17,310	23,000
Balance sheet offsetting (cash collateral against net derivative positions)	19,349	27,438
Interest rate swap derivatives		
Cash collateral posted	—	34,970
Letters of credit outstanding	—	5,000
Balance sheet offsetting (cash collateral against net derivative positions)	—	34,970

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 September 30, 2018 and December 31, 2017 (in thousands):

	September 30, 2018	December 31, 2017
Energy commodity derivatives		
Liabilities with credit-risk-related contingent features	$ 1,425	$ 1,336
Additional collateral to post	1,425	1,336
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	4,577	73,514
Additional collateral to post	4,447	18,770

NOTE 6. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

Avista Utilities

Avista Utilities’ pension and other postretirement plans have not changed during the nine months ended September 30, 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 $22.0 million in cash to the pension plan for the nine months ended September 30, 2018 and does not expect to make any further contributions in 2018.

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 nine months ended September 30 (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	2018	2017
Three months ended September 30:				
Service cost (a)	$ 5,318	$ 5,092	$ 815	$ 799
Interest cost	6,634	6,976	1,261	1,374
Expected return on plan assets	(8,101)	(7,900)	(550)	(475)
Amortization of prior service cost	71	—	(299)	(274)
Net loss recognition	1,761	2,517	1,044	1,168
Net periodic benefit cost	$ 5,683	$ 6,685	$ 2,271	$ 2,592
Nine months ended September 30:				
Service cost (a)	$ 16,218	$ 15,226	$ 2,423	$ 2,422
Interest cost	19,566	20,903	3,655	4,147
Expected return on plan assets	(24,601)	(23,700)	(1,550)	(1,425)
Amortization of prior service cost	221	—	(905)	(898)
Net loss recognition	5,691	7,380	3,261	3,761
Net periodic benefit cost	$ 17,095	$ 19,809	$ 6,884	$ 8,007

(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.

See Note 2 for discussion regarding the adoption of ASU No. 2017-07 and its impact to the presentation of pension and other postretirement benefits in the Condensed Consolidated Statements of Income and the Condensed Consolidated Balance Sheets.

NOTE 7. INCOME TAXES

The following table summarizes the significant differences in income tax expense based on the differences between our effective tax rate and the federal statutory rates (21 percent in 2018 and 35 percent in 2017) for three and nine months ended September 30 (dollars in thousands):

	Three months ended September 30,				Nine months ended September 30,			
	2018		2017		2018		2017	
Federal income taxes at statutory rates	$ 2,452	21.0 %	$ 3,364	35.0 %	$ 22,721	21.0 %	$ 48,953	35.0 %
Increase (decrease) in tax resulting from:								
Tax effect of regulatory treatment of utility plant differences	(1,521)	(13.0)	742	7.7	(4,519)	(4.2)	2,244	1.6
State income tax expense	(319)	(2.7)	(301)	(3.1)	694	0.6	1,136	0.8
Acquisition costs	122	1.0	1,997	20.8	241	0.2	2,317	1.7
Settlement of equity awards	—	—	—	—	(990)	(0.9)	(1,439)	(1.0)
Other	814	7.0	(649)	(6.8)	(680)	(0.6)	(1,663)	(1.2)
Total income tax expense	$ 1,548	13.3 %	$ 5,153	53.6 %	$ 17,467	16.1 %	$ 51,548	36.9 %

NOTE 8. 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 September 30, 2018 and December 31, 2017 (dollars in thousands):

	September 30, 2018	December 31, 2017
Balance outstanding at end of period (1)	$ 35,000	$ 105,000
Letters of credit outstanding at end of period	$ 21,230	$ 34,420
Average interest rate at end of period	2.88%	2.26%

(1) As of September 30, 2018 and December 31, 2017, 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 September 30, 2018 and December 31, 2017, 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 9. LONG-TERM DEBT AND CAPITAL LEASES

The following details long-term debt outstanding as of September 30, 2018 and December 31, 2017 (dollars in thousands):

Maturity Year	Description	Interest Rate	September 30, 2018	December 31, 2017
Avista Corp. Secured Long-Term Debt				
2018	First Mortgage Bonds	5.95%	$ —	$ 250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	—	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2020	First Mortgage Bonds	3.89%	52,000	52,000
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (1)	(1)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2044	First Mortgage Bonds	4.11%	60,000	60,000
2045	First Mortgage Bonds	4.37%	100,000	100,000
2047	First Mortgage Bonds	4.23%	80,000	80,000
2047	First Mortgage Bonds	3.91%	90,000	90,000
2048	First Mortgage Bonds (2)	4.35%	375,000	—
2051	First Mortgage Bonds	3.54%	175,000	175,000
	Total Avista Corp. secured long-term debt		1,814,200	1,711,700
Alaska Electric Light and Power Company Secured Long-Term Debt				
2044	First Mortgage Bonds	4.54%	75,000	75,000
	Total secured long-term debt		1,889,200	1,786,700
Alaska Energy and Resources Company Unsecured Long-Term Debt				
2019	Unsecured Term Loan	3.85%	15,000	15,000
	Total secured and unsecured long-term debt		1,904,200	1,801,700
Other Long-Term Debt Components				
	Capital lease obligations		57,844	62,148
	Unamortized debt discount		(905)	(626)
	Unamortized long-term debt issuance costs		(13,866)	(10,285)
	Total		1,947,273	1,852,937
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Current portion of long-term debt and capital leases		(2,629)	(277,438)
	Total long-term debt and capital leases		$ 1,860,944	$ 1,491,799

(1) In December 2010, $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due in 2032 and 2034, respectively, which had been held by Avista Corp. since 2008 and 2009, respectively, were refunded by new variable rate bond issues (Series 2010A and Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Condensed Consolidated Balance Sheets.

(2) In May 2018, the Company issued and sold $375.0 million of 4.35 percent first mortgage bonds due in 2048 through a public offering. The total net proceeds from the sale of the bonds were used to repay maturing long-term debt of $276.8 million, repay the outstanding balance under Avista Corp.'s $400.0 million committed line of credit and for other general corporate purposes. In connection with the issuance and sale of the first mortgage bonds, the Company cash-settled fourteen interest rate swap derivatives (notional aggregate amount of $275.0 million) and paid a net amount of $26.6 million. See Note 5 for a discussion of interest rate swap derivatives.

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 nine months ended September 30, 2018 and the year ended December 31, 2017:

	September 30, 2018	December 31, 2017
Low distribution rate	2.36%	1.81%
High distribution rate	3.20%	2.36%
Distribution rate at the end of the period	3.20%	2.36%

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 September 30, 2018 and December 31, 2017 (dollars in thousands):

	September 30, 2018		December 31, 2017	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 1,053,500	$ 1,116,014	$ 951,000	$ 1,067,783
Long-term debt (Level 3)	767,000	759,374	767,000	810,598
Snettisham capital lease obligation (Level 3)	57,844	56,200	59,745	61,700
Long-term debt to affiliated trusts (Level 3)	51,547	39,176	51,547	41,882

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 76.00 to 118.47, 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 September 30, 2018.

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 September 30, 2018 and December 31, 2017 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
September 30, 2018					
Assets:					
Energy commodity derivatives	$ —	$ 37,735	$ —	$ (36,851)	$ 884
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	22	(22)	—
Foreign currency exchange derivatives	—	26	—	—	26
Interest rate swap derivatives	—	18,158	—	(129)	18,029
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities (2)	1,819	—	—	—	1,819
Equity securities (2)	6,712	—	—	—	6,712
Total	$ 8,531	$ 55,919	$ 22	$ (37,002)	$ 27,470

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
Liabilities:					
Energy commodity derivatives	$ —	$ 57,615	$ —	$ (56,200)	$ 1,415
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	3,026	(22)	3,004
Power exchange agreement	—	—	5,909	—	5,909
Interest rate swap derivatives	—	4,577	—	(129)	4,448
Total	$ —	$ 62,192	$ 8,935	$ (56,351)	$ 14,776
December 31, 2017					
Assets:					
Energy commodity derivatives	$ —	$ 43,814	$ —	$ (42,550)	$ 1,264
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	183	(183)	—
Foreign currency exchange derivatives	—	32	—	(1)	31
Interest rate swap derivatives	—	7,477	—	(2,574)	4,903
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities (2)	1,638	—	—	—	1,638
Equity securities (2)	6,631	—	—	—	6,631
Total	$ 8,269	$ 51,323	$ 183	$ (45,308)	$ 14,467
Liabilities:					
Energy commodity derivatives	$ —	$ 71,342	$ —	$ (69,988)	$ 1,354
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	3,347	(183)	3,164
Power exchange agreement	—	—	13,245	—	13,245
Power option agreement	—	—	19	—	19
Foreign currency exchange derivatives	—	1	—	(1)	—
Interest rate swap derivatives	—	73,513	—	(37,544)	35,969
Total	$ —	$ 144,856	$ 16,611	$ (107,716)	$ 53,751

(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 5 for additional discussion of derivative netting.

To establish fair value for energy commodity derivatives, the Company uses quoted market prices and forward price curves to estimate the fair value of energy commodity derivative instruments included in Level 2. 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 (NYMEX) 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 September 30, 2018 and $0.2 million as of December 31, 2017.

Level 3 Fair Value

Under the power exchange agreement the Company purchases power at a price that is 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 estimates the difference between the purchase price based on the future O&M charges and forward prices for energy. The Company compares the Level 2 brokered quotes and forward price curves described above to an internally developed forward price which is based on the average O&M charges from the three surrogate nuclear power plants for the current year. The Company estimates the volumes of the transactions that will 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 September 30, 2018 (dollars in thousands):

	Fair Value (Net) at September 30, 2018		Valuation Technique	Unobservable Input	Range
Power exchange agreement	$	(5,909)	Surrogate facility pricing	O&M charges	$40.05-$52.59/MWh (1)
				Transaction volumes	292,145 MWhs
Natural gas exchange agreement	$	(3,004)	Internally derived weighted average cost of gas	Forward purchase prices	$1.40 - $1.83/mmBTU
				Forward sales prices	$1.46 - $3.21/mmBTU
				Purchase volumes	125,000 - 310,000 mmBTUs
				Sales volumes	60,000 - 310,000 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2018 are $45.61 per MWh.

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 nine months ended September 30 (dollars in thousands):

	Natural Gas Exchange Agreement	Power Exchange Agreement	Total
Three months ended September 30, 2018:			
Balance as of July 1, 2018	$ (3,480)	$ (6,345)	$ (9,825)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities (1)	476	436	912
Settlements	—	—	—
Ending balance as of September 30, 2018 (2)	$ (3,004)	$ (5,909)	$ (8,913)
Three months ended September 30, 2017:			
Balance as of July 1, 2017	$ (4,173)	$ (13,784)	$ (17,957)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities (1)	617	(2,870)	(2,253)
Settlements	(43)	—	(43)
Ending balance as of September 30, 2017 (2)	$ (3,599)	$ (16,654)	$ (20,253)
Nine months ended September 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)	(89)	1,156	1,067
Settlements	249	6,180	6,429
Ending balance as of September 30, 2018 (2)	$ (3,004)	$ (5,909)	$ (8,913)
Nine months ended September 30, 2017:			
Balance as of January 1, 2017	$ (5,885)	$ (13,449)	$ (19,334)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities (1)	2,434	(8,035)	(5,601)
Settlements	(148)	4,830	4,682
Ending balance as of September 30, 2017 (2)	$ (3,599)	$ (16,654)	$ (20,253)

(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. No shares were issued under these agreements during the nine months ended September 30, 2018. These agreements provide for the offering of a maximum of approximately 3.8 million shares, of which approximately 1.1 million remain unissued as of September 30, 2018. Subject to the satisfaction of customary conditions (including any required regulatory approvals), the Company has the right to increase the maximum number of shares that may be offered under these agreements.

NOTE 13. ACCUMULATED OTHER COMPREHENSIVE LOSS

Accumulated other comprehensive loss, net of tax, consisted of the following as of September 30, 2018 and December 31, 2017 (dollars in thousands):

	September 30, 2018	December 31, 2017
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $2,451 and $4,356, respectively (a)	$ 9,220	$ 8,090

(a) Effective January 1, 2018, the Company adopted ASU No. 2018-02. As a result of the adoption of this new standard, $1.7 million in excess tax benefits was reclassified from accumulated other comprehensive loss to retained earnings. See Note 2 for additional discussion of the adoption of this standard.

The following table details the reclassifications out of accumulated other comprehensive loss to net income by component for the three and nine months ended September 30 (dollars in thousands).

	Amounts Reclassified from Accumulated Other Comprehensive Loss				
	Three months ended September 30,		Nine months ended September 30,		
Details about Accumulated Other Comprehensive Loss Components	2018	2017	2018	2017	Affected Line Item in Statement of Income
Amortization of defined benefit pension items					
Amortization of net prior service cost	$ (228)	$ (300)	$ (684)	$ (898)	(a)
Amortization of net loss	2,962	3,637	$ 8,952	$ 10,913	(a)
Adjustment due to effects of regulation	(2,476)	(3,057)	(7,493)	(9,172)	(a)
	258	280	775	843	Total before tax
	(54)	(98)	(163)	(295)	Tax expense
	$ 204	$ 182	$ 612	$ 548	Net of tax

(a) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 6 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 nine months ended September 30 (in thousands, except per share amounts):

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Numerator:				
Net income attributable to Avista Corp. shareholders	$ 10,119	$ 4,451	$ 90,586	$ 88,338
Denominator:				
Weighted-average number of common shares outstanding-basic	65,688	64,412	65,668	64,392
Effect of dilutive securities:				
Performance and restricted stock awards	338	480	312	246
Weighted-average number of common shares outstanding-diluted	66,026	64,892	65,980	64,638
Earnings per common share attributable to Avista Corp. shareholders:				
Basic	$ 0.15	$ 0.07	$ 1.38	$ 1.37
Diluted	$ 0.15	$ 0.07	$ 1.37	$ 1.37

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.

California Refund Proceeding

In February 2016, APX, a market maker in the California Refund Proceedings in whose markets Avista Energy participated in the summer of 2000, asserted that Avista Energy and its other customer/participants may be responsible for a share of the disgorgement penalty APX may be found to owe to Pacific Gas & Electric (PG&E), Southern California Edison, San Diego Gas & Electric, the California Attorney General (AG), the California Department of Water Resources (CERS), and the California Public Utilities Commission (together, the "California Parties"). The penalty arises as a result of the FERC's finding that APX committed violations in the California market in the summer of 2000. APX is making these assertions despite Avista Energy having been dismissed in FERC Opinion No. 536 from the on-going administrative proceeding at the FERC regarding potential wrongdoing in the California markets in the summer of 2000. APX has identified Avista Energy's share of APX's exposure to be as much as $16.0 million even though no wrongdoing allegations are specifically attributable to Avista Energy. Avista Energy believes its settlement with the California Parties in 2014 insulates it from any such liability and that as a dismissed party it cannot be drawn back into the litigation. On May 3, 2018, the FERC issued an order, Order on Compliance Filings, resolving in the Company's favor the last indirect exposure the Company had related to the California Refund Proceedings. That order, which fully absolved the Company of any further exposure, was not challenged and is now final and not subject to appeal.

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 Pending Acquisition by Hydro One

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

In connection with the proposed acquisition, as of the date of this quarterly report, the three lawsuits that had been filed in the United States District Court for the Eastern District of Washington have been voluntarily dismissed by the plaintiffs. Those cases were captioned as follows:

- *Jenβ v. Avista Corporation., et al.*, No. 2:17-cv-00333 (E.D. Wash.) (filed September 25, 2017);
- *Samuel v. Avista Corporation*, *et al*., No. 2:17-cv-00334 (E.D. Wash.) (filed September 26, 2017); and
- *Sharpenter v. Avista Corporation., et al.*, No. 2:17-cv-00336 (E.D. Wash.) (filed September 26, 2017)

There remains one lawsuit that has been 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).

This lawsuit was filed against Hydro One Limited, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch, as well as all members of the Company's Board of Directors, namely Erik Anderson, Kristianne Blake, Donald Burke, Rebecca Klein, Scott Maw, Scott Morris, Marc Racicot, Heidi Stanley, John Taylor and Janet Widmann. While Avista Corp. is not a named defendant in this lawsuit, the Company has the obligation to indemnify members of its Board of Directors.

The complaint generally alleges that the members of the Board breached their fiduciary duties by, among other things, conducting an allegedly inadequate sale process and agreeing to the acquisition at a price that allegedly undervalues Avista Corporation, and that Hydro One Limited, Olympus Holding Corp., and Olympus Corp. aided and abetted those purported breaches of duty. The aiding and abetting claims were brought only against Hydro One Limited, Olympus Holding Corp. and

Olympus Corp. The complaint seeks various remedies, including monetary damages, attorneys' fees and expenses. The complaint has been stayed by the court until the closing of the transaction at which time the plaintiff will have the option to file an amended complaint within 30 days of such closing. If the amended complaint is not filed within the 30 days the suit will be dismissed.

All defendants deny any wrongdoing in connection with the proposed acquisition and plan to vigorously defend against all pending claims; however, the Company cannot at this time predict the eventual outcome.

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 (ICNU), 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.

The total attrition allowance approved by the WUTC in Order 05 and reaffirmed in Order 06 was $35.2 million, with $28.3 million related to electric and $6.9 million related to natural gas. The Company cannot predict the outcome of this matter at this time and cannot estimate how much, if any, of the attrition allowance may be removed from the general rate cases. The Company will participate in any regulatory process that is yet to be established by the WUTC.

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 19 of the Notes to Consolidated Financial Statements" in the 2017 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 September 30, 2018:						
Operating revenues	$ 279,549	$ 9,570	$ 289,119	$ 6,894	$ —	$ 296,013
Resource costs	98,461	3,058	101,519	—	—	101,519
Other operating expenses (2)	76,355	3,005	79,360	7,347	—	86,707
Depreciation and amortization	44,569	1,466	46,035	207	—	46,242
Income (loss) from operations	35,317	1,787	37,104	(660)	—	36,444
Interest expense (3)	23,560	896	24,456	462	(313)	24,605
Income taxes	2,564	188	2,752	(1,204)	—	1,548
Net income (loss) attributable to Avista Corp. shareholders	11,935	824	12,759	(2,640)	—	10,119
Capital expenditures (4)	108,907	4,176	113,083	257	—	113,340
For the three months ended September 30, 2017:						
Operating revenues	$ 280,776	$ 10,864	$ 291,640	$ 5,456	$ —	$ 297,096
Resource costs	104,516	4,052	108,568	—	—	108,568
Other operating expenses (2) (5)	79,188	3,469	82,657	6,598	—	89,255
Depreciation and amortization	41,516	1,452	42,968	137	—	43,105
Income (loss) from operations (5)	32,880	1,298	34,178	(1,279)	—	32,899
Interest expense (3)	23,132	895	24,027	215	(71)	24,171
Income taxes	5,972	44	6,016	(863)	—	5,153
Net income (loss) attributable to Avista Corp. shareholders	5,419	427	5,846	(1,395)	—	4,451
Capital expenditures (4)	109,066	1,073	110,139	1,050	—	111,189
For the nine months ended September 30, 2018:						
Operating revenues	$ 970,525	$ 33,715	$ 1,004,240	$ 20,432	$ —	$ 1,024,672
Resource costs	353,148	8,958	362,106	—	—	362,106
Other operating expenses (2)	230,342	9,049	239,391	20,714	—	260,105
Depreciation and amortization	132,022	4,397	136,419	587	—	137,006
Income (loss) from operations	174,310	10,488	184,798	(869)	—	183,929
Interest expense (3)	71,953	2,686	74,639	1,179	(712)	75,106
Income taxes	17,716	2,098	19,814	(2,347)	—	17,467
Net income (loss) attributable to Avista Corp. shareholders	91,727	5,878	97,605	(7,019)	—	90,586
Capital expenditures (4)	288,046	8,169	296,215	809	—	297,024

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the nine months ended September 30, 2017:						
Operating revenues	$ 992,904	$ 38,002	$ 1,030,906	$ 17,161	$ —	$ 1,048,067
Resource costs	366,590	10,315	376,905	—	—	376,905
Other operating expenses (2) (5)	225,980	9,236	235,216	19,863	—	255,079
Depreciation and amortization	123,249	4,347	127,596	482	—	128,078
Income (loss) from operations	199,376	12,080	211,456	(3,184)	—	208,272
Interest expense (3)	68,641	2,684	71,325	558	(112)	71,771
Income taxes	49,881	3,582	53,463	(1,915)	—	51,548
Net income (loss) attributable to Avista Corp. shareholders	85,623	5,961	91,584	(3,246)	—	88,338
Capital expenditures (4)	283,081	4,772	287,853	1,219	—	289,072
Total Assets:						
As of September 30, 2018:	$ 5,223,031	$ 280,826	$ 5,503,857	$ 79,426	$ (25,885)	$ 5,557,398
As of December 31, 2017:	$ 5,177,878	$ 278,688	$ 5,456,566	$ 73,241	$ (15,075)	$ 5,514,732

(1) Intersegment eliminations reported as interest expense represent intercompany interest.
(2) Other operating expenses for Avista Utilities for the three and nine months ended September 30, 2018 include acquisition costs of $1.0 million and $2.6 million, respectively, which are separately disclosed on the Condensed Consolidated Statements of Income. The three and nine months ended September 30, 2017 include acquisition costs of $6.7 million and $8.0 million, respectively, which are also separately disclosed.
(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.
(5) Effective January 1, 2018, the Company adopted ASU No. 2017-07, which resulted in a $1.9 million and $5.7 million reclassification of the non-service cost component of pension and other postretirement benefit costs for the three and nine months ended September 30, 2017, respectively. The costs were reclassified from utility other operating expenses to other expense (income) - net on the Condensed Consolidated Statements of Income.

NOTE 17. PENDING ACQUISITION BY HYDRO ONE

On July 19, 2017, Avista Corp. entered into a Merger Agreement, by and among Hydro One, Olympus Holding Corp., a wholly owned subsidiary of Hydro One (US parent), and Olympus Corp., a wholly owned subsidiary of US parent (Merger Sub). Subject to the terms and conditions of the Merger Agreement, Merger Sub will be merged with and into Avista Corp., with Avista Corp. surviving as an indirect, wholly-owned subsidiary of Hydro One. Hydro One, based in Toronto, is Ontario’s largest electricity transmission and distribution provider.

At the effective time of the acquisition, each share of Avista Corp. common stock issued and outstanding, other than shares of Avista Corp. common stock that are owned by Hydro One, US Parent (as defined in the Merger Agreement) or Merger Sub or any of their respective subsidiaries, will be converted automatically into the right to receive an amount in cash equal to $53, without interest.

Hydro One Leadership Changes

The following disclosure is based upon information provided by Hydro One. On July 11, 2018, Hydro One announced that it had entered into an agreement with the Province of Ontario (“Province”), which is Hydro One's largest shareholder (owning approximately 47 percent of the outstanding shares of common stock) for the purpose of the orderly replacement of the board of directors of Hydro One and Hydro One Inc. and the retirement of the chief executive officer effective July 11, 2018.

Other key highlights of the agreement with the Province included:

- Each of the directors of Hydro One in place at the time of the agreement resigned and were replaced by nominees identified as set out below.
- The new board of directors initially consists of 10 members. The Province nominated four directors and the remaining six nominees were identified through an ad hoc nominating committee comprised of representatives from four of the

five largest Hydro One shareholders other than the Province. The new board of directors was announced on August 14, 2018, and is expected to serve until Hydro One's next annual meeting or until they otherwise cease to hold office.

- The new board of directors is responsible for appointing a new chief executive officer who will also be appointed as the eleventh member of the board of directors.
- Hydro One has agreed to consult with the Province in respect of future matters of executive compensation.
- Hydro One's chief financial officer was appointed as acting chief executive officer until such time as the board of directors can appoint a new chief executive officer.

The leadership changes described above, in and of themselves, do not directly relate to or affect the obligations of any party under the Merger Agreement. Upon entering their board of director positions, the new board adopted a resolution reaffirming Hydro One's commitment to the merger and the related regulatory commitments described below. See further discussion below regarding developments with respect to the regulatory proceedings to approve the transaction.

Closing Conditions, Required Approvals

Consummation of the acquisition is subject to the satisfaction or waiver, if permissible under applicable law, of specified closing conditions, including, but not limited to, (i) the approval of the acquisition by the holders of a majority of the outstanding shares of Avista Corp. Common Stock, (ii) the receipt of regulatory approvals required to consummate the acquisition, including approval from the FERC, the Committee on Foreign Investment in the United States (CFIUS), the Federal Communications Commission (FCC), the WUTC, IPUC, MPSC, OPUC, and the RCA, and (iii) meeting the requirements of the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act), as amended. Under the HSR Act and the rules and regulations promulgated thereunder, the acquisition may not be completed until notification and report forms have been filed with the U.S. Department of Justice (DOJ) and the Federal Trade Commission (FTC) and the applicable waiting period has expired or been terminated.

The transaction is expected to close in the fourth quarter of 2018 subject to remaining referenced approvals and the satisfaction or waiver of other specified conditions.

The Merger Agreement may be terminated by each of the Company and US Parent under certain circumstances, including if the acquisition is not consummated by September 30, 2018, (subject to an extension of up to six months by either party, if all of the conditions to closing, other than the conditions related to obtaining required regulatory approvals, the absence of a law or injunction preventing the consummation of the acquisition and the absence of a Burdensome Condition, as defined in the Merger Agreement, in any required regulatory approval, have been satisfied). On September 19, 2018, Avista Corp. provided notice to Hydro One of its election to extend the Merger Agreement end date to March 29, 2019, and Hydro One acknowledged receipt of such notice.

The table below presents the approvals required for the consummation of the acquisition by Hydro One, as well as the date the Company filed an approval request and the current status of each required approval.

Required Approval	Approval Request Filing Date	Status	
Avista Corp. shareholder approval	October 2, 2017	Approved November 21, 2017, no further action	
FERC	September 14, 2017	Approved January 16, 2018, no further action	
HSR Act	March 6, 2018	Approved April 6, 2018, no further action	
CFIUS	February 9, 2018	Approved May 18, 2018, no further action	
FCC	April 13, 2018	Approved May 4, 2018; approval extended through April 13, 2019	(a)
WUTC	September 14, 2017	Settlement agreement filed with WUTC	(b)
IPUC	September 14, 2017	Settlement agreement filed with IPUC	(c)
OPUC	September 14, 2017	Settlement agreement filed with OPUC	(d)
RCA	November 21, 2017	Approved June 4, 2018	(e)
MPSC	September 14, 2017	Approved July 10, 2018	(f)

(a) **FCC** - The transaction was approved by the FCC on May 4, 2018; however, this approval expired on November 5, 2018. Since the acquisition was not completed by the expiration date, the Company filed an extension request with the FCC. On October 3, 2018, the FCC granted the Company's extension request through April 13, 2019.

(b) **Washington** - On March 27, 2018, Avista Corp. and Hydro One filed an all-parties, all-issues settlement agreement with the WUTC recommending approval of the acquisition of the Company by Hydro One. This represents a full settlement that all parties, including the WUTC Staff, have agreed results in a net benefit to the Company's Washington customers. The settlement agreement is subject to WUTC approval.

The settlement includes financial and non-financial commitments by the Company. The settlement, if approved, would result in a rate credit of approximately $31 million over a 5-year period. In the settlement, Hydro One and Avista Corp. also agreed to a number of other financial commitments, including providing funding for low income participation in new renewable energy and replacing certain manufactured homes. If the settlement is approved, the Company's financial commitments in Washington would total approximately $42 million, including the rate credits. As a result of settlement agreements in Washington, Oregon and Idaho and final approvals in Alaska and Montana, the total financial commitment across all states, if approved, would be approximately $78.6 million. No costs associated with the transaction will be recovered from Avista Corp. or Hydro One customers.

The settlement agreement also provides for the use of a portion of Avista Corp.'s excess deferred federal income taxes for the purpose of accelerating the depreciation schedule for Colstrip Units 3 & 4 to reflect a remaining useful life of those units through December 31, 2027. In addition, included in the financial commitments described above is funding toward a Colstrip community transition fund which is intended to help the Colstrip community transition from coal-fired generation in the event of a future closure. The settlement does not reflect any agreement with respect to the ultimate closure of Colstrip Units 3 & 4 as that decision would be made in conjunction with the other owners of Colstrip.

In response to the developments regarding the change in the leadership and board of Hydro One, on July 20, 2018, the WUTC issued a Notice of Extension of Time for Process and Deliberation. Under state law, the WUTC extended the time allowed for it to enter an order in the proceeding by up to four months, until December 14, 2018.

(c) **Idaho** - On April 13, 2018, Avista Corp. and Hydro One filed an all-issues settlement agreement with the IPUC recommending approval of the acquisition of the Company by Hydro One. The settlement agreement is subject to IPUC approval. Subsequent to the filing of the settlement agreement with the IPUC, a new intervenor, the Avista Customer Group, was allowed into the case and it is not part of the original settlement agreement.

The settlement agreement reflects similar financial and non-financial commitments that align in value with those agreed to in Washington. The Idaho portion of the shareholder-funded rate credits is approximately $16 million over a 5-year period. The total amount of financial commitments for Idaho, including the rate credit, is approximately $21 million.

The settlement agreement in Idaho does not address Colstrip in the same manner as Washington; rather the parties to the settlement agreement have recommended that Colstrip be addressed in a separate filing requesting revised depreciation rates. The Company will be proposing that a portion of the benefits from the TCJA be set aside for the purpose of accelerating the depreciation schedule for Colstrip Units 3 & 4 to reflect a remaining useful life of those units through December 31, 2027.

In response to the developments regarding the change in the leadership and board of Hydro One, the IPUC adopted a new procedural schedule, which calls for a technical hearing on November 26, 2018. The parties, including Hydro One and Avista Corp., requested a December 14, 2018 target date for the final order; however, there is no statutory deadline in Idaho and an order may not be received by the requested date.

(d) **Oregon** - On May 25, 2018, Avista Corp. and Hydro One filed an all-parties, all-issues settlement agreement with the OPUC related to the Oregon merger proceeding. The settlement agreement is subject to review and approval by the OPUC. Subsequent to the filing of the settlement agreement with the OPUC, the Citizens' Utility Board requested to be removed from the settlement agreement due to the Hydro One leadership changes described above.

The settlement agreement in Oregon includes financial and non-financial commitments. Under the settlement agreement, customers in Oregon would receive benefits in the form of a rate credit of approximately $8 million over a 5-year period, along with additional safeguards to assure the continued financial well-being of Avista Corp. The total amount of financial commitments for Oregon, including the rate credit, is approximately $10 million.

Also, as part of the commitments included in the Oregon settlement agreement, Avista Corp. has agreed that the base rates established on November 1, 2017 as part of its latest Oregon natural gas general rate case will remain in effect until at least January 1, 2020.

In response to the developments regarding the change in the leadership and board of Hydro One, on July 25, 2018, the OPUC held a Prehearing Conference and adopted a new Procedural Schedule which calls for additional pre-filed testimony, with a placeholder for a potential hearing, should the OPUC request it. The parties, including Hydro One and Avista Corp., requested a December 14, 2018 target date for the final order and the OPUC adopted this target date.

(e) **Alaska** - On June 4, 2018, Avista Corp. and Hydro One received approval from the RCA on the proposed merger with financial and non-financial commitments. The commitments included among other items, that AEL&P's capital structure is maintained at its previously ordered 46 percent debt and 54 percent equity levels and that the parties adhere to all commitments filed with the RCA on April 3, 2018, which included enhanced community giving and provides a $1 million rate credit over five years for AEL&P's customers. This rate credit period would begin at the close of the transaction.

(f) **Montana** - On July 10, 2018, Avista Corp. and Hydro One received approval from the MPSC on the proposed merger, with conditions. The MPSC did not accept, for ratemaking purposes in Montana, an accelerated 2027 depreciation schedule for Colstrip, as otherwise agreed to by the parties in Washington. On May 10, 2018, Avista and Hydro One signed a Memorandum of Agreement with the City of Colstrip, whereby Avista and Hydro One agreed that upon the completion of the transaction, $4.5 million of funding would be made available to assist the community of Colstrip in meeting its immediate and future needs.

Avista Corp. and Hydro One intend to continue to work with the various commissions, their staff and other parties to try and satisfy any concerns associated with the proposed transaction.

Other Information Related to the Acquisition

The Merger Agreement also contains customary representations, warranties and covenants of Avista Corp., Hydro One, US Parent and Merger Sub. These covenants include, among others, an obligation on behalf of Avista Corp. to operate its business in the ordinary course until the acquisition is consummated, subject to certain exceptions. In addition, the parties are required to use reasonable best efforts to obtain any required regulatory approvals.

Avista Corp. has made certain additional customary covenants, including, among others, and subject to certain exceptions, a customary non-solicitation covenant prohibiting Avista Corp. from soliciting, providing non-public information or entering into discussions or negotiations concerning proposals relating to alternative business combination transactions, except as and to the extent permitted under the Merger Agreement with respect to an unsolicited written Takeover Proposal (as defined in the Merger Agreement) made prior to the approval of the acquisition by Avista Corp.'s shareholders if, among other things, Avista Corp.'s board of directors determines in good faith that such Takeover Proposal is or could be reasonably expected to lead to a Superior Proposal (as defined in the Merger Agreement) and that failure to take such actions would reasonably be expected to be inconsistent with its fiduciary duties under applicable law. No such Takeover Proposals have been received.

The Merger Agreement may be terminated by Avista Corp. and Hydro One by mutual consent and by either Avista Corp. or Hydro One under certain circumstances, including if the acquisition is not consummated by September 30, 2018, which has been extended to March 29, 2019. The Merger Agreement also provides for certain additional termination rights for each of Avista Corp. and Hydro One. Upon termination of the Merger Agreement under certain specified circumstances, including (i) termination by Avista Corp. in order to enter into a definitive agreement with respect to a Superior Proposal, or (ii) termination by Hydro One following a withdrawal by Avista Corp.'s board or directors of its recommendation of the Merger Agreement, Avista Corp. will be required to pay Hydro One the Company Termination Fee of $103.0 million. Avista Corp. will also be required to pay Hydro One the Company Termination Fee in the event Avista Corp. signs or consummates any specified alternative transaction within twelve months following the termination of the Merger Agreement under certain circumstances. In addition, if the Merger Agreement is terminated under certain circumstances due to the failure to obtain required regulatory approvals, the imposition of a Burdensome Condition with respect to a required regulatory approval, or the breach by Hydro One, US Parent or Merger Sub of their obligations in respect to obtaining regulatory approvals, Hydro One will be required to pay Avista Corp. a termination fee of $103.0 million.

The Company is incurring significant acquisition costs associated with the pending Hydro One acquisition consisting primarily of consulting, banking fees, legal fees and employee time, and are not being passed through to customers. In addition, a significant portion of these costs are not deductible for income tax purposes.

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.

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 September 30, 2018, the related condensed consolidated statements of income and comprehensive income for the three-month and nine-month periods ended September 30, 2018 and 2017, the related condensed consolidated statements of equity and cash flows for the nine-month periods ended September 30, 2018 and 2017, 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, 2017, and the related consolidated statements of income, comprehensive income, equity, and cash flows for the year then ended (not presented herein); and in our report dated February 20, 2018, 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, 2017, 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
November 6, 2018

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 2017 Form 10-K.

Business Segments

Our business segments have not changed during the nine months ended September 30, 2018. See the 2017 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 nine months ended September 30 (dollars in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Avista Utilities	$ 11,935	$ 5,419	$ 91,727	$ 85,623
AEL&P	824	427	5,878	5,961
Other	(2,640)	(1,395)	(7,019)	(3,246)
Net income attributable to Avista Corp. shareholders	$ 10,119	$ 4,451	$ 90,586	$ 88,338

Executive Level Summary

Overall Results

Net income attributable to Avista Corp. shareholders was $10.1 million for the three months ended September 30, 2018, an increase from $4.5 million for the three months ended September 30, 2017. Net income attributable to Avista Corp. shareholders was $90.6 million for the nine months ended September 30, 2018, an increase from $88.3 million for the nine months ended September 30, 2017.

The increase in earnings for the third quarter of 2018 was due to an increase in earnings at Avista Utilities and AEL&P, partially offset by an increase in losses at our other businesses. The increase in earnings for the year-to-date was due to an increase in earnings at Avista Utilities, partially offset by a decrease in earnings at AEL&P and our other businesses.

Avista Utilities' earnings increased for the third quarter of 2018 and year-to-date primarily due to a decrease in acquisition costs relating to the pending acquisition by Hydro One and the positive impact of general rate increases and customer growth. These increases were partially offset for both the third quarter and the year-to-date by increased transmission and distribution operating and maintenance costs (other operating expenses), depreciation and amortization, and interest expense.

AEL&P earnings increased for the third quarter of 2018, but decreased slightly for the year-to-date. The fluctuations were primarily due to a decrease in other operating expenses as compared to the same periods in the prior year. For the year-to-date, there was an increase in depreciation and amortization and other miscellaneous expenses.

The increase in losses at our other businesses for the year-to-date were primarily related to impairment losses on investments and net losses from our other equity method investments. In addition, we had increased 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.

Pending Acquisition by Hydro One

On July 19, 2017, Avista Corp. entered into a Merger Agreement that provides 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, the transaction is expected to close during the fourth quarter of 2018. At the effective time of the acquisition, each share of Avista Corp. common stock issued and outstanding other than shares of Avista Corp. common stock that are owned by Hydro One, Olympus Holding Corp., a wholly owned subsidiary of Hydro One (US parent), and Olympus Corp., a wholly owned subsidiary of US parent (Merger Sub) or any of their respective subsidiaries, will be converted automatically into the right to receive an amount in cash equal to $53, without interest. For further information, see Note 17 of the "Notes to Condensed Consolidated Financial Statements” as well as "Regulatory Matters."

Federal Income Tax Law Changes

On December 22, 2017, the TCJA was signed into law, with most provisions of the new law effective on January 1, 2018. As a result of the TCJA and its reduction of the corporate income tax rate from 35 percent to 21 percent (among many other changes in the law), we recorded a regulatory liability associated with the revaluing of our deferred income tax assets and liabilities to the new corporate tax rate. The total net amount of the regulatory liability associated with the TCJA is $435.4 million as of September 30, 2018, compared to $442.3 million as of December 31, 2017, which reflects the amounts to be refunded to customers through the regulatory process. We expect the Avista Utilities plant related amounts will be returned to customers over a period of approximately 36 years using the ARAM. We expect the AEL&P plant related amounts to be returned to customers over a period of approximately 40 years using the Reverse South Georgia Method. The regulatory liability attributable to non-plant excess deferred taxes of approximately $18.5 million (among all jurisdictions) will be returned to customers as prescribed by the Washington and Idaho regulatory orders discussed below, whereas the return of Oregon’s share of this balance, as well as all other Oregon tax benefits, are yet to be determined.

Because most of the provisions of the TCJA were effective as of January 1, 2018 but customers' rates included a 35 percent corporate tax rate built in from prior general rate cases, we began accruing for a refund to customers for the change in federal income tax expense beginning January 1, 2018 forward. For Washington and Idaho, this accrual was recorded until all benefits prior to a permanent rate change were properly captured through the deferral process. Refunds have begun, as discussed below, to Washington and Idaho customers through tariffs or other regulatory mechanisms or proceedings. For Oregon, we will continue to defer these benefits until reflected in a future regulatory proceeding as approved by the OPUC. As of September 30, 2018, we have recorded a customer refund liability of $17.7 million (among all jurisdictions) associated with the difference between the actual corporate tax rate and the corporate tax rate built into customer rates.

For Washington, effective May 1, 2018, the WUTC approved base rates reflecting a permanent reduction of $26.9 million for electric and $5.5 million for natural gas, as a result of 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. The WUTC also ordered, effective June 1, 2018, one-year temporary reductions of $7.9 million for electric and $3.2 million for natural gas, passed back to customers through temporary tariff schedules. These reductions reflect 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.

In addition, the WUTC agreed to set aside $10.4 million of 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 (per Avista/Hydro One merger agreement settlement in principle). The tax benefits being utilized are related to non-plant excess deferred income taxes. Although the parties have agreed to the acceleration of depreciation of Colstrip Units 3 & 4, the settlement in principle does not reflect any agreement with respect to the ultimate closure of Colstrip Units 3 & 4, since that decision would have to be made in conjunction with the other owners of Colstrip.

For Idaho, on May 31, 2018, the IPUC approved the all-party settlement agreement related to the income tax benefits associated with the TCJA filed by the parties on April 30, 2018. Effective June 1, 2018, through separate tariff schedules, until such time as these changes can be reflected in base rates within the next general rate case, 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 excess deferred income taxes. This permanent 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 addition to the above amounts, the IPUC also set aside approximately $12.0 million of 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 (per Avista/Hydro One merger settlement in principle), or for other purposes. 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. There are also $0.5 million in tax benefits attributable to natural gas, which were included in the PGA filing effective November 1, 2018. These tax benefits include the natural gas amounts associated with non-plant excess deferred income taxes, and the customer refund liability deferred for the period January 1, 2018 to May 31, 2018.

For AEL&P, the RCA approved a settlement agreement between AEL&P and the Attorney General filed on June 15, 2018 (Order 3). Per Order 3, effective August 1, 2018, AEL&P reduced firm customer base rates by an overall 6.7 percent (approximately $2.4 million annually), to reflect income tax expense reductions associated with the TCJA. The RCA also approved AEL&P's proposal to refund to customers a one-time credit amount equal to the 6.7 percent rate reduction for bills rendered between January 1 and July 31, 2018. AEL&P completed all one-time credit refunds during the third quarter of 2018. The impact of the TCJA on AEL&P’s deferred income taxes will be addressed in AEL&P’s next general rate case, due to be filed by August 30, 2021.

See the 2017 Form 10-K for a detailed discussion of the TCJA, including the impact to us and any risks that may be associated with the new law.

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 that concluded our 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.

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, PC filed in Thurston County Superior Court a Petition for Judicial Review of the WUTC's Orders 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.

The total attrition allowance approved by the WUTC was $35.2 million, with $28.3 million related to electric and $6.9 million related to natural gas. The Company cannot predict the outcome of this matter at this time and cannot estimate how much, if any, of the attrition allowance may be removed from the general rate cases. The Company will participate in any regulatory process that is yet to be established by the WUTC. See "Note 15 of the Notes to Condensed Consolidated Financial Statements" for further discussion of this matter.

2016 General Rate Cases

In December 2016, the WUTC issued an order related to our Washington electric and natural gas general rate cases that were originally filed with the WUTC in February 2016. The WUTC order denied the Company's proposed electric and natural gas rate increase requests of $38.6 million and $4.4 million, respectively. Accordingly, our electric and natural gas retail rates remained unchanged in Washington State following the order.

The primary reason given by the WUTC in reaching its conclusion was that, in our request, we did not follow an “appropriate methodology” to show the existence of attrition, as between historical data and current and projected data. In support of its decision, the WUTC stated that we did not demonstrate that our current revenue was insufficient for covering costs and providing the opportunity to earn a reasonable return during the 2017 rate period. The WUTC also stated that we did not demonstrate that our capital expenditures and increased operating costs are both necessary and immediate.

We did not appeal the WUTC's decision to the courts and instead focused on new general rate cases.

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 base revenues of $23.2 million, an increase of $14.5 million in power supply costs and a decrease of $26.9 million for the impacts from the TCJA.

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.

In the order, the WUTC also agreed to withhold $10.4 million of the electric non-plant excess deferred federal income taxes that resulted from the TCJA for the purpose of accelerating the depreciation schedule for Colstrip Units 3 & 4 to reflect a remaining useful life of those units through December 31, 2027. This finding by the WUTC was in recognition of the settlement agreement in the Pending Acquisition of Avista by Hydro One proceeding which provides for the use of a portion of Avista Corp.'s non-plant excess deferred federal income taxes for the purpose of accelerating the depreciation schedule for Colstrip Units 3 & 4 to reflect a remaining useful life of those units through December 31, 2027.

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.

In addition to the above, in filed testimony to our general rate cases, the WUTC Staff recommended the exclusion of our 2016 settlement costs of interest rate swaps from the cost of capital calculation. In the final order, the WUTC disagreed with WUTC Staff and did not disallow the settlement costs of our interest rate swaps. However, they did recommend that we make changes to our interest rate risk hedging policy to be more risk responsive. We are evaluating changes to our policy to meet the WUTC recommendations.

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 additional rate changes will take effect on 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 a 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.

Oregon General Rate Cases

2016 General Rate Case

In September 2017, the OPUC approved a settlement agreement between us and other parties to our natural gas general rate case that was filed with the OPUC in November 2016, which resolved all issues in the case.

The OPUC approved rates designed to increase annual base revenues by 5.9 percent or $3.5 million. A rate adjustment of $2.6 million became effective October 1, 2017, and a second adjustment of $0.9 million became effective on November 1, 2017 to cover specific capital projects identified in the settlement agreement, which were completed in October.

In addition, in the settlement agreement we agreed to non-recovery of certain utility plant expenditures, which resulted in a write-off of $0.8 million in the second quarter of 2017.

The settlement agreement reflects a 7.35 percent ROR with a common equity ratio of 50 percent and a 9.4 percent ROE.

In the settlement agreement that was filed with the OPUC in May 2018 associated with the proposed Hydro One transaction, as part of the commitments, Avista Corp. has agreed that the base rates established on November 1, 2017 as part of this general rate case will remain in effect until at least January 1, 2020.

Alaska Electric Light and Power Company

Alaska General Rate Case

In November 2017, the RCA approved an all-party settlement agreement related to AEL&P's electric general rate case, which was originally filed in September 2016. The settlement agreement is designed to increase base electric revenue by 3.86 percent or $1.3 million, making permanent the interim rate increase approved by the RCA in 2016.

The agreement reflects an 8.91 percent ROR with a common equity ratio of 58.18 percent and an 11.95 percent ROE.

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 a liability of $35.4 million as of September 30, 2018 and a liability of $37.5 million as of December 31, 2017. These deferred natural gas costs balances represent amounts due to customers.

Power Cost Deferrals and Recovery Mechanisms

The ERM in Washington 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. See the 2017 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 $30.2 million as of September 30, 2018, compared to a liability of $23.7 million as of December 31, 2017. These deferred power cost balances represent amounts due to customers.

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 $9.3 million as of September 30, 2018, compared to a liability of $6.1 million as of December 31, 2017. 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. During the first quarter of 2018, the FCA in Idaho was extended for a one-year term through December 31, 2019. See the 2017 Form 10-K for a discussion of the mechanisms in each jurisdiction.

Total net cumulative decoupling deferrals among all jurisdictions were regulatory assets of $11.1 million as of September 30, 2018 and $16.5 million as of December 31, 2017. These decoupling assets represent amounts due from customers. Total net earnings sharing balances among all jurisdictions were regulatory liabilities of $1.6 million as of September 30, 2018 and $5.8 million as of December 31, 2017. 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 2018 and 2017 related to the decoupling and earnings sharing mechanisms.

State Regulatory Approval Requirements Related to the Pending Acquisition by Hydro One

See "Note 17 of the Notes to Condensed Consolidated Financial Statements" for discussion of the regulatory approvals related to the pending acquisition by Hydro One, as well as their current status.

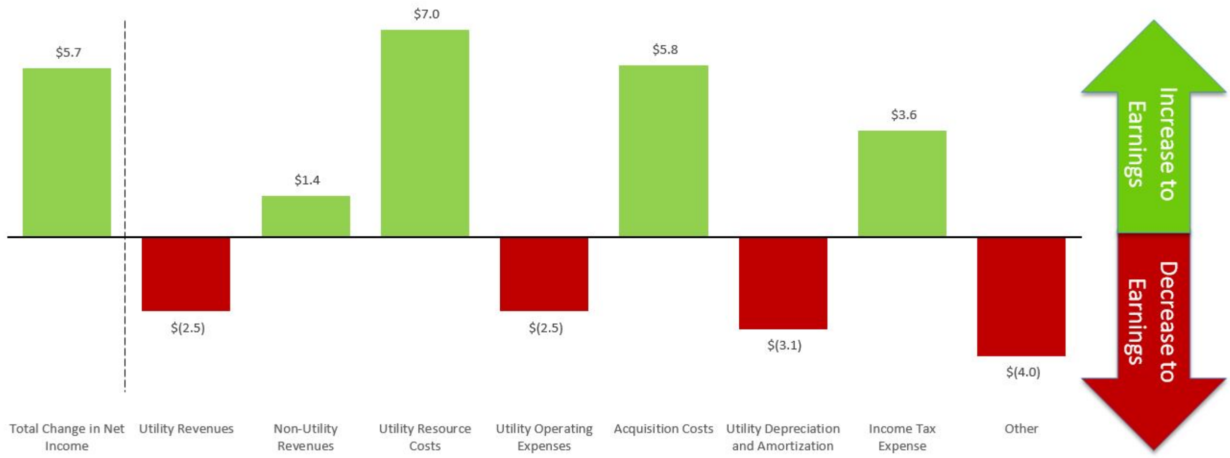
Results of Operations - Overall

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 September 30, 2018 compared to the three months ended September 30, 2017

The following graph shows the total change in net income attributable to Avista Corp. shareholders for the third quarter of 2017 to the third quarter of 2018, 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 due to lower retail electric sales volumes (due to cooler weather) and decreases to retail rates related to federal income tax law changes that lowered the corporate tax rate from 35 percent to 21 percent. Effective May 1, 2018 in Washington and June 1, 2018 in Idaho, base rates reflect the lower 21 percent corporate tax. Base rates in Oregon continue to have the 35 percent corporate tax rate built in and we are deferring the impact. There was also a decrease in wholesale electric and natural gas revenues (primarily from a decrease in sales prices) and sales of fuel. This was partially offset by an increase in revenue from general rate increases in Washington, Idaho and Oregon, customer growth and decoupling. AEL&P's revenues decreased due to a decrease in retail rates associated with the federal income tax law change and the adoption of ASU No. 2014-09 effective January 1, 2018. The adoption of ASU No. 2014-09 had no impact on net income. See "Notes 2 and 4 of the Notes to Condensed Consolidated Financial Statements" for further information on the adoption of this ASU.

Utility resource costs decreased at both Avista Utilities and AEL&P. The decrease at Avista Utilities was primarily due to a decrease in fuel for generation (resulting from a decrease in thermal generation because of an outage at Colstrip, as well as a decrease in natural gas fuel prices). There was also a decrease in natural gas purchased (due to a decrease in volumes and prices). Power purchases increased during the quarter due to an increase in volumes and wholesale prices. The decrease at AEL&P was due to a decrease in deferred power supply expenses.

The increase in utility other operating expenses was due to an increase at Avista Utilities, partially offset by a decrease at AEL&P. The increase at Avista Utilities was the result of an increase in transmission and distribution operating and maintenance costs. The decrease at AEL&P was due to a decrease in generation maintenance and supplies expense.

The acquisition costs are related to the pending Hydro One acquisition. These costs decreased for the third quarter of 2018 because 2018 consisted primarily of employee time incurred directly related to the transaction, whereas the third quarter of 2017 included financial advisers' fees, legal fees, consulting fees and employee time. None of the acquisition costs are being passed through to customers.

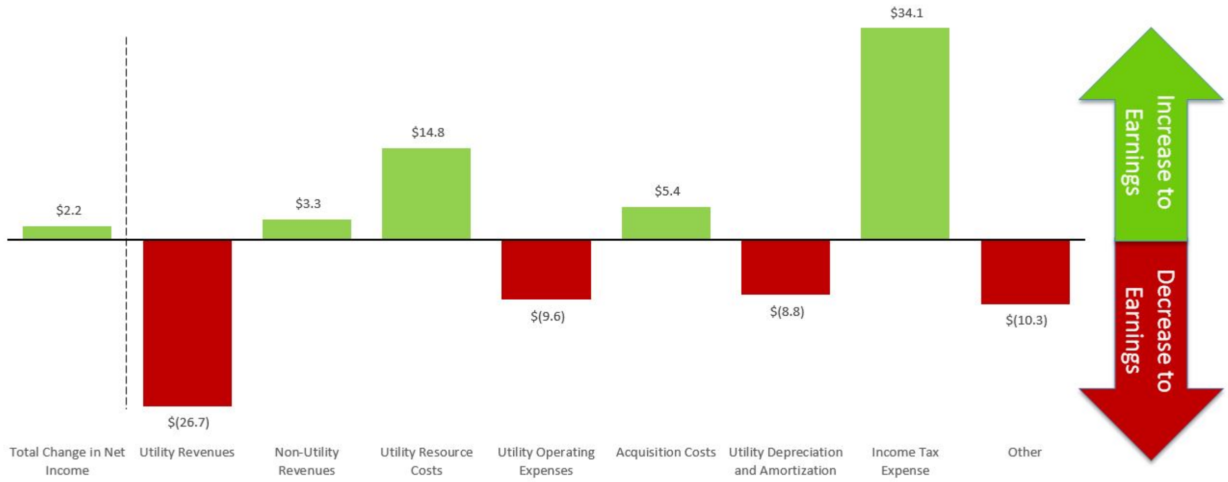
Utility depreciation and amortization increased due to additions to utility plant.

Income taxes decreased due to federal income tax law changes, which reduced the corporate tax rate from 35 percent to 21 percent. Our effective tax rate was 13.3 percent for the third quarter of 2018 compared to 53.6 percent for the third quarter of 2017. In addition to the enacted tax rate decrease, the amortization of plant excess deferred income taxes under the ARAM decreased our effective tax rate for the third quarter of 2018. During the third quarter of 2017 the effective tax rate was higher because the majority of acquisition costs incurred during that period, which reduced income before income taxes, were not deductible for tax purposes and thus did not reduce income tax expense. See "Note 7 of the Notes to Condensed Consolidated Financial Statements" for further details and a reconciliation of our effective tax rate.

The increase in other was primarily related to an increase in interest expense due to additional debt being outstanding during 2018 as compared to 2017. Also, there was an impairment of an investment during the third quarter of 2018.

Nine months ended September 30, 2018 compared to the nine months ended September 30, 2017

The following graph shows the total change in net income attributable to Avista Corp. shareholders for the nine months ended September 30, 2017 to the nine months ended September 30, 2018, 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 due to lower retail electric and natural gas sales volumes (due to warmer weather in the heating season and cooler weather in the cooling season) and an accrual for refunds to customers and decreases to retail rates related to federal income tax law changes. As our customers' rates had the 35 percent corporate tax rate built in from prior general rate cases through May 1, 2018 in Washington and June 1, 2018 in Idaho, we deferred the impact of the change beginning January 1, 2018. Effective May 1, 2018 in Washington and June 1, 2018 in Idaho, base rates reflect the lower 21 percent corporate tax. Base rates in Oregon continue to have the 35 percent corporate tax rate built in and we are deferring the impact. There is no impact to our net income, as there was a corresponding decrease in income tax expense. There was also a decrease in wholesale natural gas revenues (due to a decrease in prices). This was partially offset by an increase in wholesale electric revenues (due to increased volumes) and an increase in revenue from general rate increases in Washington, Idaho and Oregon, customer growth and decoupling. AEL&P's revenues decreased due to a decrease in retail rates associated with the federal income tax law change and the adoption of ASU No. 2014-09 effective January 1, 2018. The adoption of ASU No. 2014-09 had no impact on net income. See "Notes 2 and 4 of the Notes to Condensed Consolidated Financial Statements" for further information on the adoption of this ASU.

Utility resource costs decreased at both Avista Utilities and AEL&P. The decrease at Avista Utilities was primarily due to a decrease in natural gas purchased (due to a decrease in prices and volumes) and a decrease in natural gas regulatory amortizations. The decrease at AEL&P was due to a decrease in deferred power supply expenses.

The increase in utility other operating expenses was due to an increase at Avista Utilities, partially offset by a decrease at AEL&P. The increase at Avista Utilities was the result of an increase in transmission and distribution operating and maintenance costs. The decrease at AEL&P was due to a decrease in generation maintenance and supplies expense.

The acquisition costs are related to the pending Hydro One acquisition. These costs decreased for 2018 because 2018 consisted primarily of employee time incurred directly related to the transaction, whereas 2017 included financial advisers' fees, legal fees, consulting fees and employee time. None of the acquisition costs are being passed through to customers.

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

Income taxes decreased due to federal income tax law changes, which reduced the corporate tax rate from 35 percent to 21 percent. Our effective tax rate was 16.1 percent for 2018, compared to 36.9 percent for 2017. In addition to the enacted tax rate decrease, the amortization of plant excess deferred income taxes under the ARAM and the settlement of equity awards during the first quarter of 2018 decreased our effective tax rate. See "Note 7 of the Notes to Condensed Consolidated Financial Statements" for further details and a reconciliation of our effective tax rate.

The increase in other was primarily related to an increase in interest expense due to additional debt being outstanding during 2018 as compared to 2017. Also, there were impairment losses on investments and net losses from our other equity method investments. In addition, we had increased expenses at one of our subsidiaries associated with the insolvency of the general contractor on a renovation project. The general contractor's insolvency resulted in the recording of a liability to various subcontractors. During the second quarter of 2017, we had increased compliance costs at one of our subsidiaries that did not reoccur during 2018, which partially offset the increased costs for the year-to-date 2018 as compared to the year-to-date 2017.

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. 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."

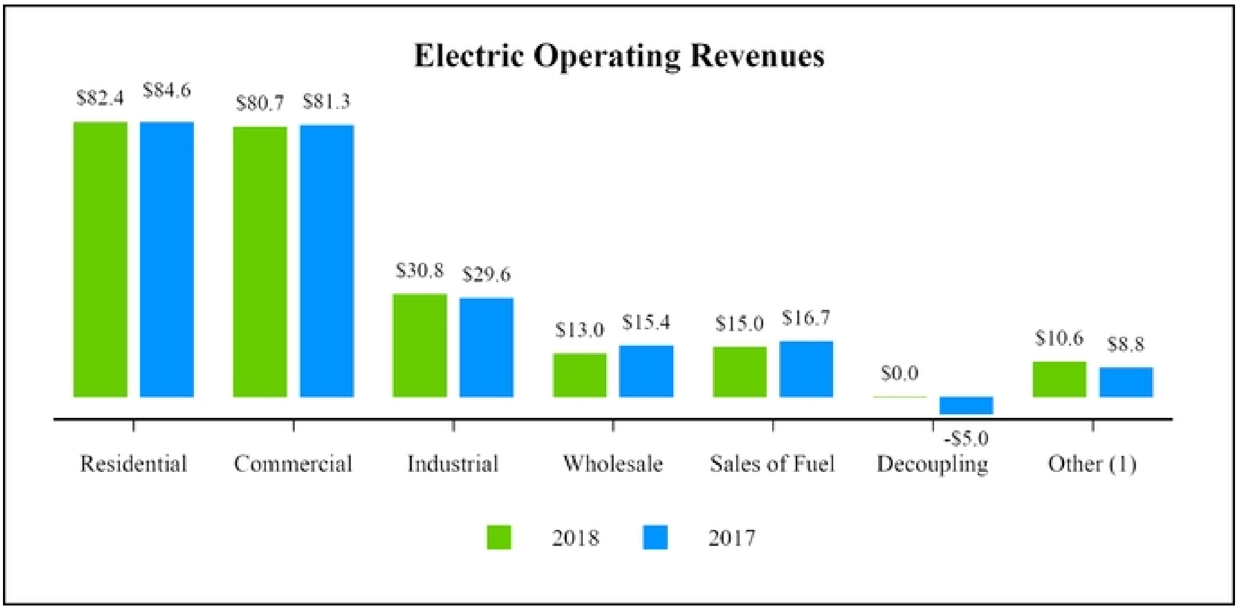
The presentation of electric utility margin and natural gas utility margin is intended to enhance the understanding of operating performance. We use these measures internally and believe they provide useful information to investors in their analysis of how changes in loads (due to weather, economic or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

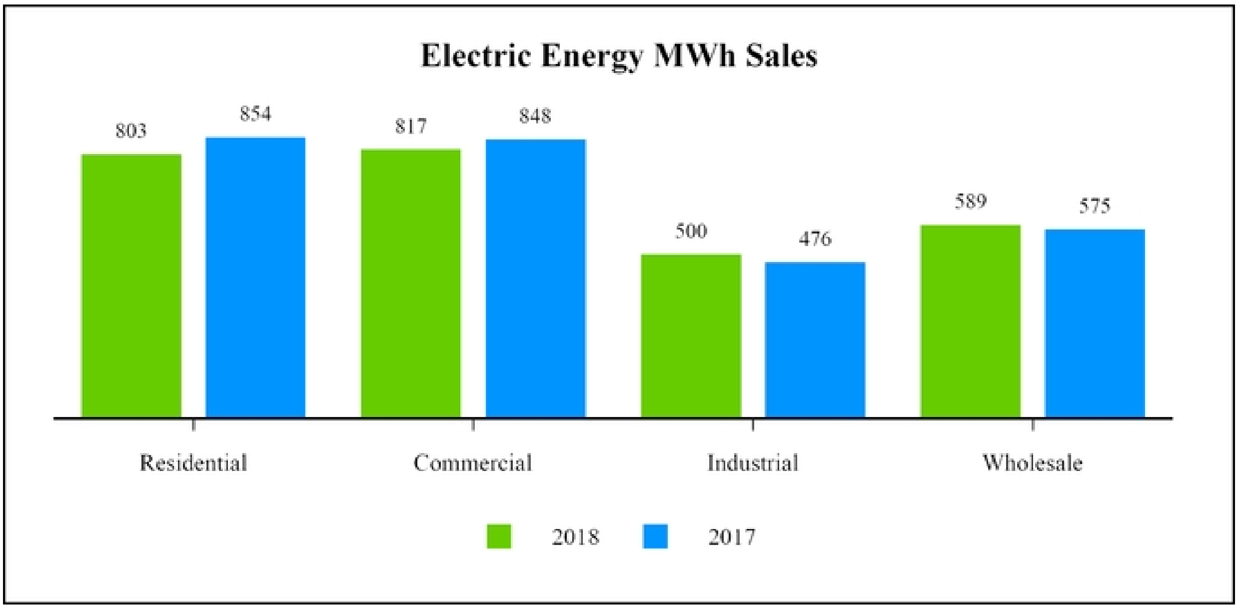
Three months ended September 30, 2018 compared to the three months ended September 30, 2017

Utility Operating Revenues

The following graphs present Avista Utilities' electric operating revenues and megawatt-hour (MWh) sales for the three months ended September 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.



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 September 30 (dollars in thousands):

	Electric Operating Revenues	
	2018	2017
Current year decoupling deferrals (a)	$ 3,738	$ (4,410)
Amortization of prior year decoupling deferrals (b)	(3,782)	(600)
Total electric decoupling revenue	$ (44)	$ (5,010)

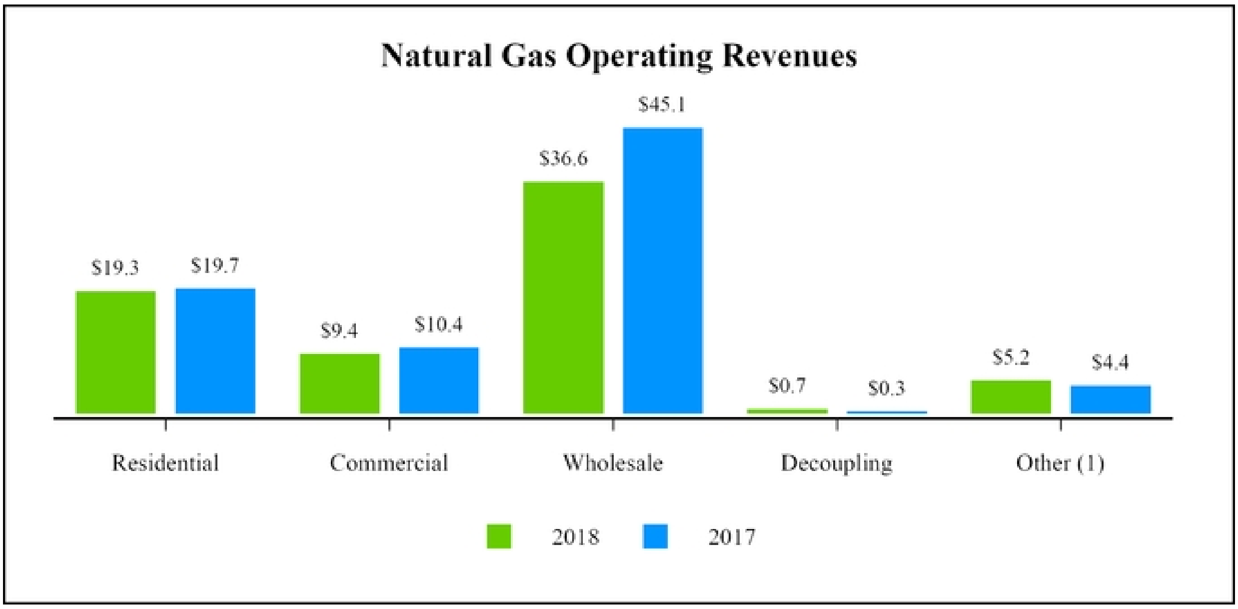
(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative numbers are decreases in decoupling revenue in the current year and will be rebated to customers in future years.

(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.

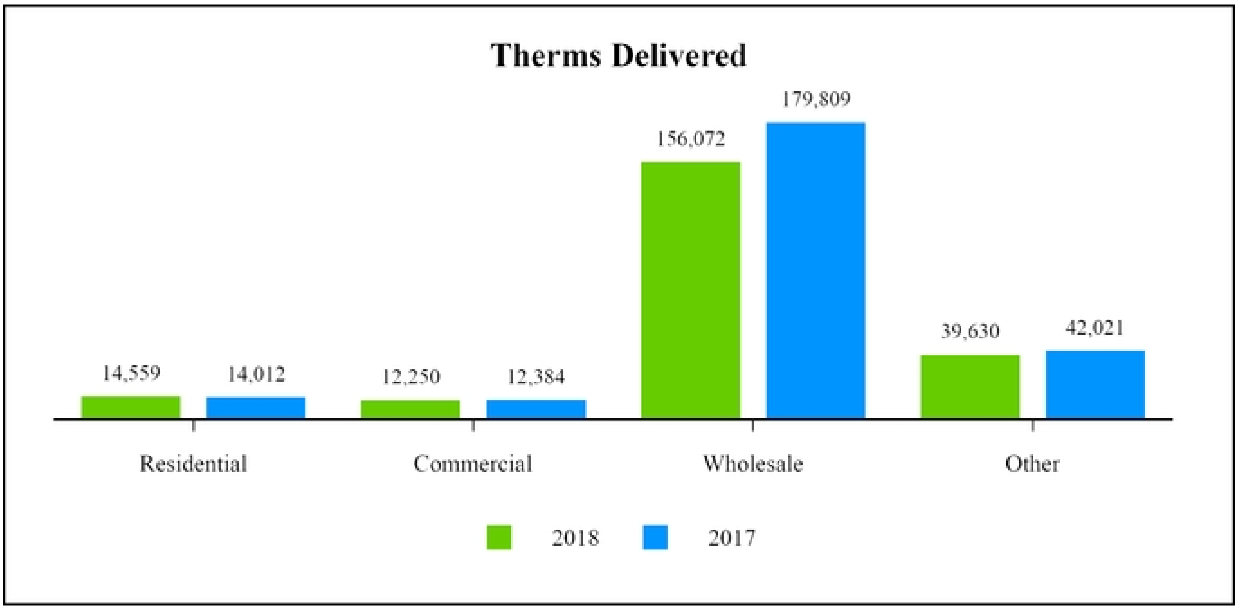
Total electric revenues increased $1.0 million for the third quarter of 2018 as compared to the third quarter of 2017 primarily due to the following:

- a $1.4 million decrease in retail electric revenue due to a decrease in total MWhs sold (decreased revenues $5.2 million), partially offset by an increase in revenue per MWh (increased revenues $3.8 million).
    - The decrease in total retail MWhs sold was the result of weather that was cooler than the prior year (which decreased electric cooling loads), partially offset by customer growth. Compared to the third quarter of 2017, residential electric use per customer decreased 7 percent and commercial use per customer decreased 4 percent. Cooling degree days in Spokane were 4 percent below normal and 29 percent below the third quarter of 2017.
    - The increase in revenue per MWh was primarily due to general rate increases in Idaho (effective January 1, 2018) and Washington (effective May 1, 2018), as well as an increase in decoupling surcharge rates. This was partially offset by rate decreases associated with the lower corporate tax rate.
- a $2.4 million decrease in wholesale electric revenues due to a decrease in sales prices (decreased revenues $2.7 million), partially offset by an increase in sales volumes (increased revenues $0.3 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $1.7 million decrease in sales of fuel due to a decrease in sales of natural gas fuel as part of thermal generation resource optimization activities. For the third quarter of 2018, $11.6 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For the third quarter of 2017, $13.6 million of these sales were made to our natural gas operations.
- a $5.0 million increase in electric revenue due to decoupling. Weather was cooler than normal in the third quarter of 2018, which resulted in decoupling deferral surcharges related to the current year.

The following graphs present Avista Utilities' natural gas operating revenues and therms delivered for the three months ended September 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.



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 September 30 (dollars in thousands):

	Natural Gas Operating Revenues	
	2018	2017
Current year decoupling deferrals (a)	$ 1,619	$ 600
Amortization of prior year decoupling deferrals (b)	(969)	(325)
Total natural gas decoupling revenue	$ 650	$ 275

(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 $8.7 million for the third quarter of 2018 as compared to the third quarter of 2017 primarily due to the following:

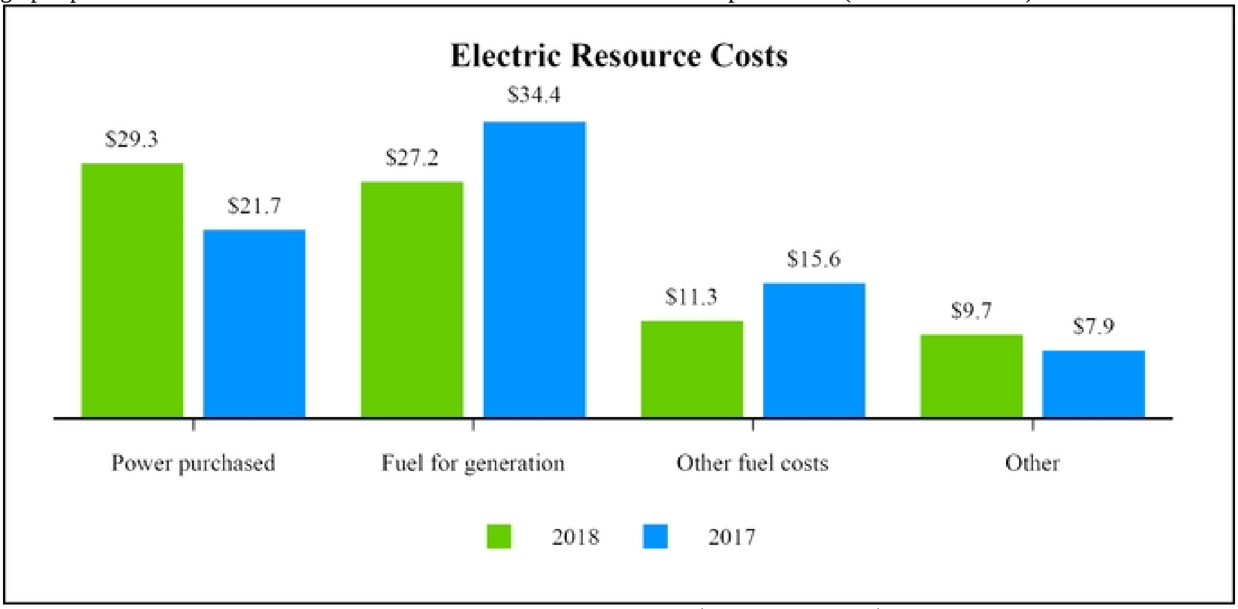
- a $1.6 million decrease in natural gas retail revenues due to lower retail rates (decreased revenues $2.1 million), partially offset by a slight increase in volumes (increased revenues $0.5 million).
    - We sold slightly more retail natural gas in the third quarter of 2018 as compared to the third quarter of 2017. Retail natural gas loads and changes in customer usage during the third quarter are typically not significant to the full year.
    - Lower retail rates were due to PGAs and rate decreases associated with the lower corporate tax rate, partially offset by general rate increases in Oregon (effective October 1 and November 1, 2017), Idaho (effective January 1, 2018) and Washington (effective May 1, 2018), as well as an increase in decoupling surcharge rates.
- an $8.5 million decrease in wholesale natural gas revenues due to a decrease in prices (decreased revenues $2.9 million) and a decrease in volumes (decreased revenues $5.6 million). In the third quarter of 2018, $12.4 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In the third quarter of 2017, $17.0 million of these sales were made to our electric generation operations. 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 $0.4 million increase in natural gas revenue due to decoupling.

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

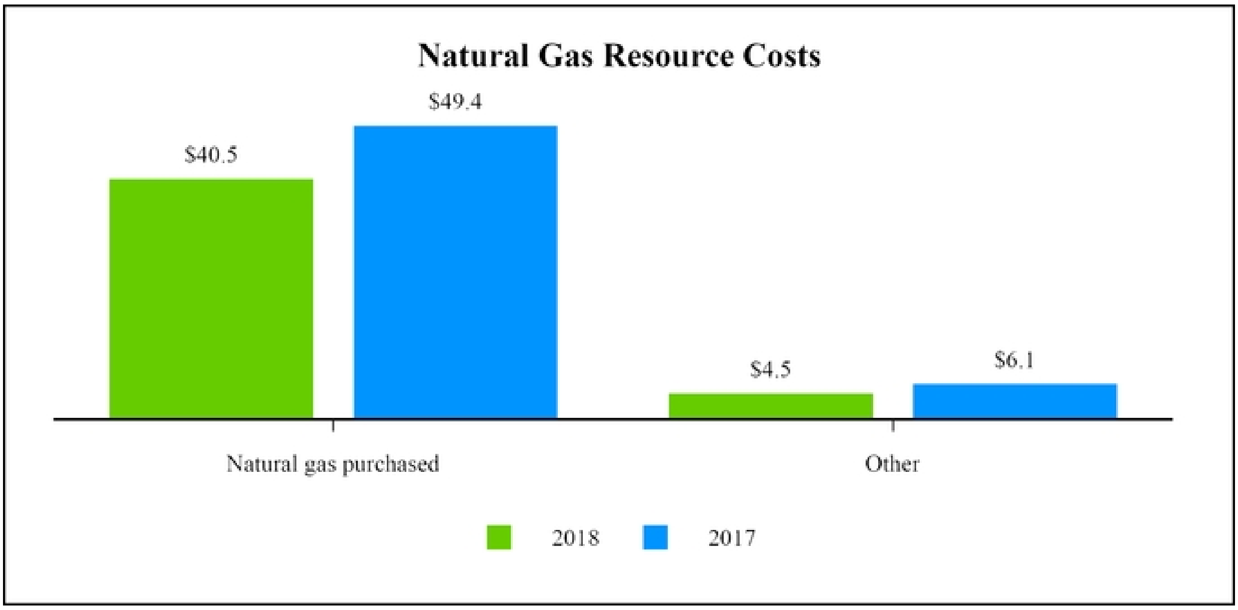
	Electric Customers		Natural Gas Customers	
	2018	2017	2018	2017
Residential	339,765	334,274	313,922	306,706
Commercial	42,396	42,241	35,200	35,087
Interruptible	—	—	39	37
Industrial	1,317	1,336	245	253
Public street and highway lighting	593	577	—	—
Total retail customers	384,071	378,428	349,406	342,083

Utility Resource Costs

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



Total electric resource costs in the graph above include intracompany resource costs of $12.4 million and $17.0 million for the three months ended September 30, 2018 and September 30, 2017, respectively.



Total natural gas resource costs in the graph above include intracompany resource costs of $11.6 million and $13.6 million for the three months ended September 30, 2018 and September 30, 2017, respectively.

Total electric resource costs decreased $2.0 million for the third quarter of 2018 as compared to the third quarter of 2017 primarily due to the following:

- a $7.6 million increase in purchased power due to an increase in the volume of power purchases (increased costs $1.8 million) and an increase in wholesale prices (increased costs $5.8 million). The fluctuation in volumes and prices was primarily the result of our optimization activities during the quarter.

- a $7.2 million decrease in fuel for generation primarily due to a decrease in thermal generation (due to an outage at Colstrip), as well as a decrease in natural gas fuel prices.
- a $4.3 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 $0.4 million decrease from net amortizations and deferrals of power costs.
- a $2.1 million net increase from other regulatory amortizations and other electric resource costs.

Total natural gas resource costs decreased $10.5 million for the third quarter of 2018 as compared to the third quarter of 2017 primarily due to the following:

- a $8.9 million decrease in natural gas purchased due to a decrease in the price of natural gas (decreased costs $3.9 million) and a decrease in total therms purchased (decreased costs $5.0 million).
- a $1.5 million decrease from net amortizations and deferrals of natural gas costs.

Utility Margin

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

	Electric		Natural Gas		Intracompany		Total	
	2018	2017	2018	2017	2018	2017	2018	2017
Operating revenues	$ 232,448	$ 231,419	$ 71,189	$ 79,938	$ (24,088)	$ (30,581)	$ 279,549	$ 280,776
Resource costs	77,576	79,598	44,973	55,499	(24,088)	(30,581)	98,461	104,516
Utility margin	$ 154,872	$ 151,821	$ 26,216	$ 24,439	$ —	$ —	$ 181,088	$ 176,260

Electric utility margin increased $3.1 million and natural gas utility margin increased $1.8 million in the third quarter of 2018 compared to the third quarter of 2017.

Electric utility margin increased primarily due to general rate increases in Idaho (effective January 1, 2018) and Washington (effective May 1, 2018), as well as customer growth. These increases were partially offset by the impact of the reduction in the corporate tax rate. For the third quarter of 2018, we had a $0.2 million pre-tax expense under the ERM in Washington, compared to a $1.0 million pre-tax expense for the third quarter of 2017. For the full year of 2018, we expect to be in a benefit position under the ERM within the 90 percent customer/10 percent Company sharing band, primarily due to above normal hydroelectric generation and lower natural gas fuel prices. Because of the above normal hydroelectric generation and lower natural gas fuel prices, we were able to engage in optimization activities to capture value in the energy markets.

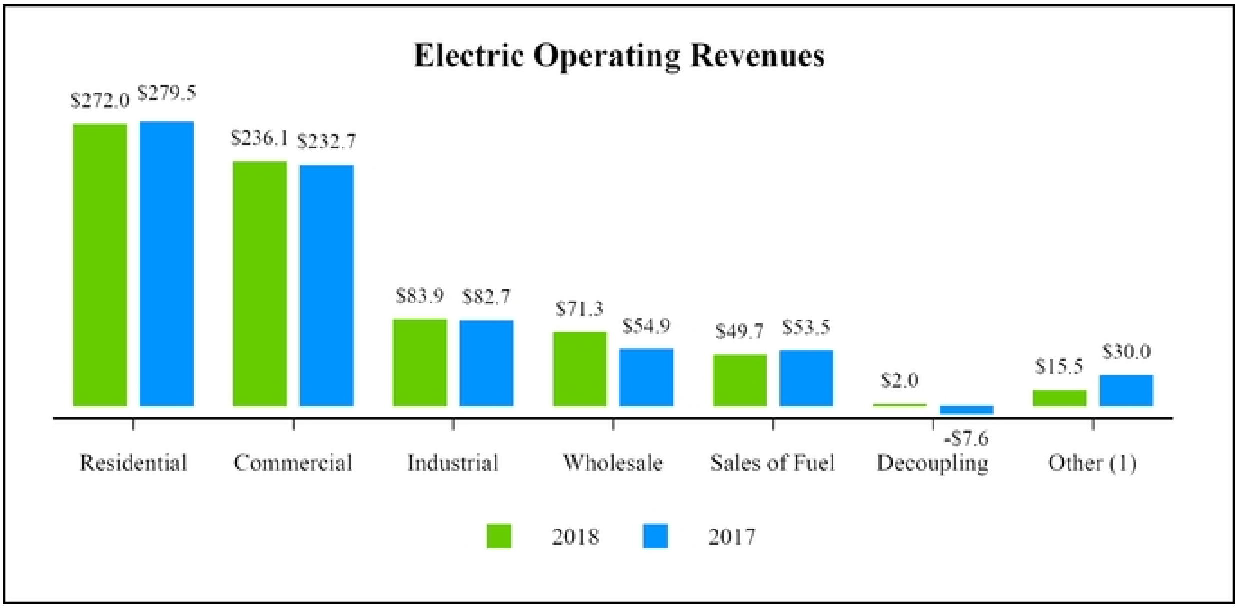
Natural gas utility margin increased primarily due to general rate increases in Oregon (effective October 1 and November 1, 2017), Idaho (effective January 1, 2018) and Washington (effective May 1, 2018), as well as customer growth. These increases were partially offset by the impact of the reduction in the corporate tax rate.

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.

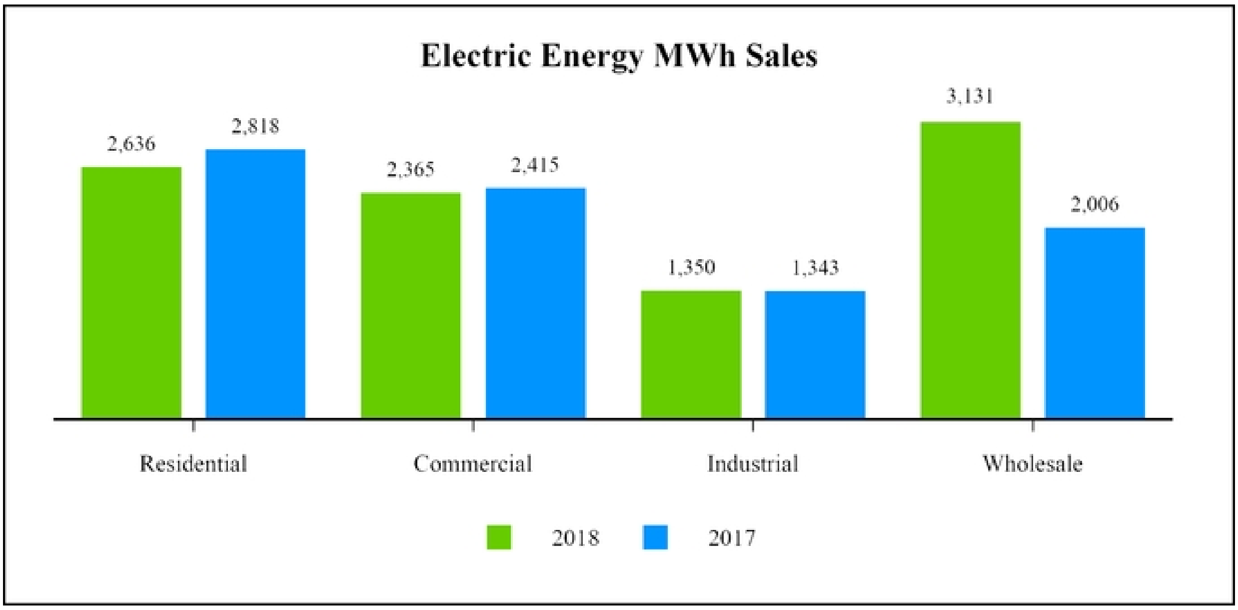
Nine months ended September 30, 2018 compared to the nine months ended September 30, 2017

Utility Operating Revenues

The following graphs present Avista Utilities' electric operating revenues and megawatt-hour (MWh) sales for the nine months ended September 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.



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 nine months ended September 30 (dollars in thousands):

	Electric Operating Revenues	
	2018	2017
Current year decoupling deferrals (a)	$ 14,024	$ (5,207)
Amortization of prior year decoupling deferrals (b)	(12,058)	(2,360)
Total electric decoupling revenue	$ 1,966	$ (7,567)

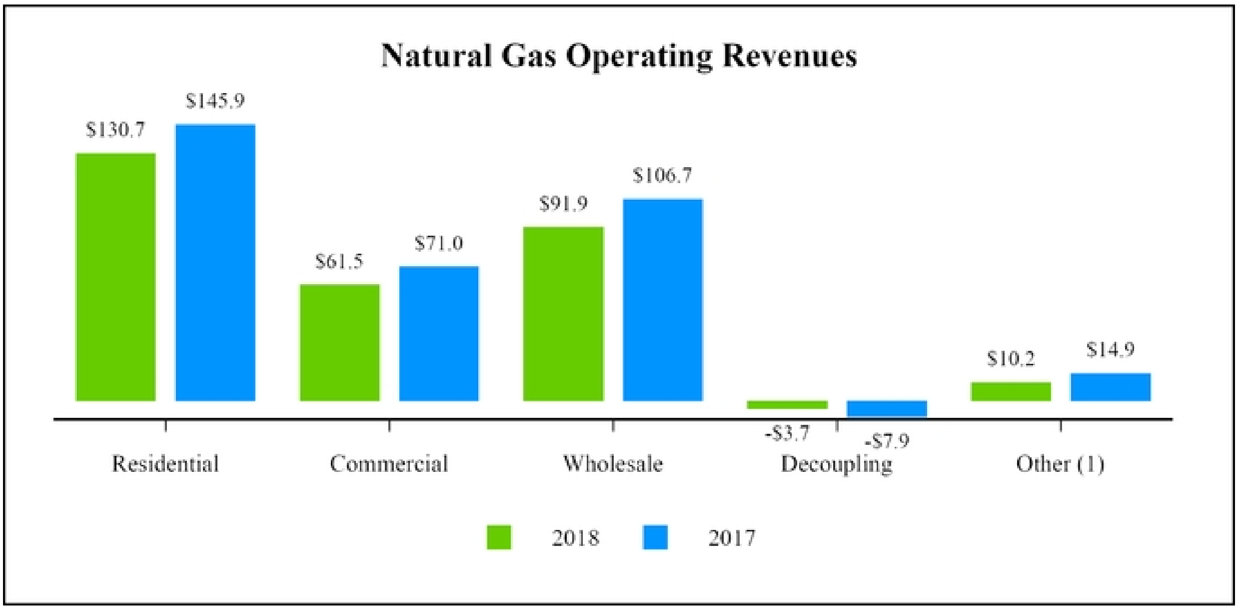
(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative numbers are decreases in decoupling revenue in the current year and will be rebated to customers in future years.

(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.

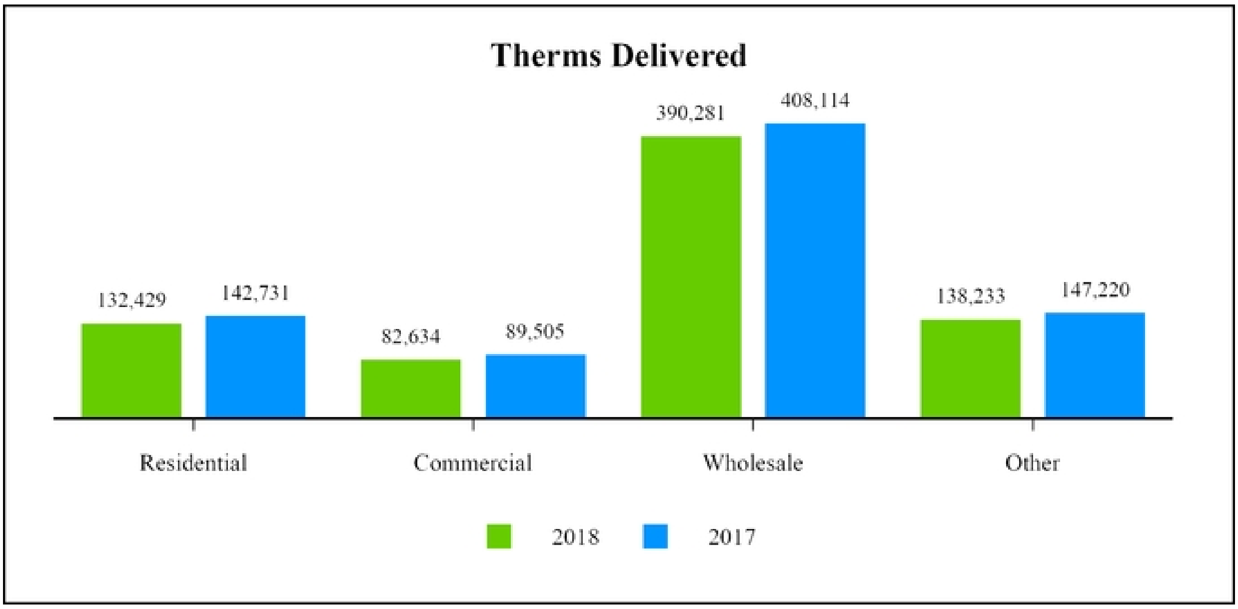
Total electric revenues increased $4.8 million for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017 primarily due to the following:

- a $2.7 million decrease in retail electric revenue due to a decrease in total MWhs sold (decreased revenues $21.2 million), partially offset by an increase in revenue per MWh (increased revenues $18.5 million).
    - The decrease in total retail MWhs sold was the result of weather that was warmer than the prior year during the heating season (which decreased electric heating loads) and cooler than the prior year during the cooling season (which decreased electric cooling loads), partially offset by customer growth. Compared to the nine months ended September 30, 2017, residential electric use per customer decreased 8 percent and commercial use per customer decreased 3 percent. Heating degree days in Spokane were 8 percent below normal and 12 percent below the first nine months of 2017. Year-to-date 2018 cooling degree days were 5 percent below normal and 30 percent below the prior year.
    - The increase in revenue per MWh was primarily due to general rate increases in Idaho (effective January 1, 2018) and Washington (effective May 1, 2018), as well as an increase in decoupling surcharge rates. This was partially offset by rate decreases associated with the lower corporate tax rate.
- a $16.4 million increase in wholesale electric revenues due to an increase in sales volumes (increased revenues $25.6 million), partially offset by a decrease in sales prices (decreased revenues $9.2 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $3.8 million decrease in sales of fuel due to a decrease in sales of natural gas fuel as part of thermal generation resource optimization activities. For the nine months ended September 30, 2018, $20.5 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For the nine months ended September 30, 2017, $26.9 million of these sales were made to our natural gas operations.
- a $9.6 million increase in electric revenue due to decoupling. Weather was warmer than normal during the heating season and cooler than normal during the cooling season in 2018, which resulted in decoupling surcharges for the first nine months of 2018.
- an $11.1 million decrease in electric revenue due to net deferrals for refunds to customers related to the 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 through May 1, 2018 in Washington and June 1, 2018 in Idaho, we deferred the impact of the change beginning January 1, 2018. Effective May 1, 2018 in Washington and June 1, 2018 in Idaho, base rates reflect the lower 21 percent corporate tax.
- a $3.1 million decrease in transmission revenue (included in other revenue in the graph above).

The following graphs present Avista Utilities' natural gas operating revenues and therms delivered for the nine months ended September 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.



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 nine months ended September 30 (dollars in thousands):

	Natural Gas Operating Revenues	
	2018	2017
Current year decoupling deferrals (a)	$ 4,225	$ (4,738)
Amortization of prior year decoupling deferrals (b)	(7,955)	(3,141)
Total natural gas decoupling revenue	$ (3,730)	$ (7,879)

(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 $40.0 million for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017 primarily due to the following:

- a $25.3 million decrease in natural gas retail revenues due to a decrease in volumes (decreased revenues $15.2 million) and lower retail rates (decreased revenues $10.1 million).
    - We sold less retail natural gas in the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017 due to warmer weather during the heating season, partially offset by customer growth. Compared to the first nine months of 2017, residential natural gas use per customer decreased 9 percent and commercial use per customer decreased 8 percent. Heating degree days in Spokane were 8 percent below normal and 12 percent below the first nine months of 2017. Heating degree days in Medford were 5 percent below normal, and 4 percent below the first nine months of 2017.
    - Lower retail rates were due to PGAs and rate decreases associated with the lower corporate tax rate, partially offset by general rate increases in Washington, Oregon and Idaho, as well as an increase in decoupling surcharge rates.
- a $14.8 million decrease in wholesale natural gas revenues due to a decrease in prices (decreased revenues $10.6 million) and a decrease in volumes (decreased revenues $4.2 million). In the nine months ended September 30, 2018, $30.0 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In the nine months ended September 30, 2017, $36.5 million of these sales were made to our electric generation operations. 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 $4.2 million increase in natural gas revenue due to decoupling. Weather was warmer than normal in the first nine months of 2018, which resulted in decoupling surcharges.
- a $4.9 million decrease in natural gas revenue due to net deferrals for refunds to customers related to the 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 through May 1, 2018 in Washington and June 1, 2018 in Idaho, we deferred the impact of the change beginning January 1, 2018. Effective May 1, 2018 in Washington and June 1, 2018 in Idaho, base rates reflect the lower 21 percent corporate tax. Base rates in Oregon continue to have the 35 percent corporate tax rate built in and we are deferring the impact.

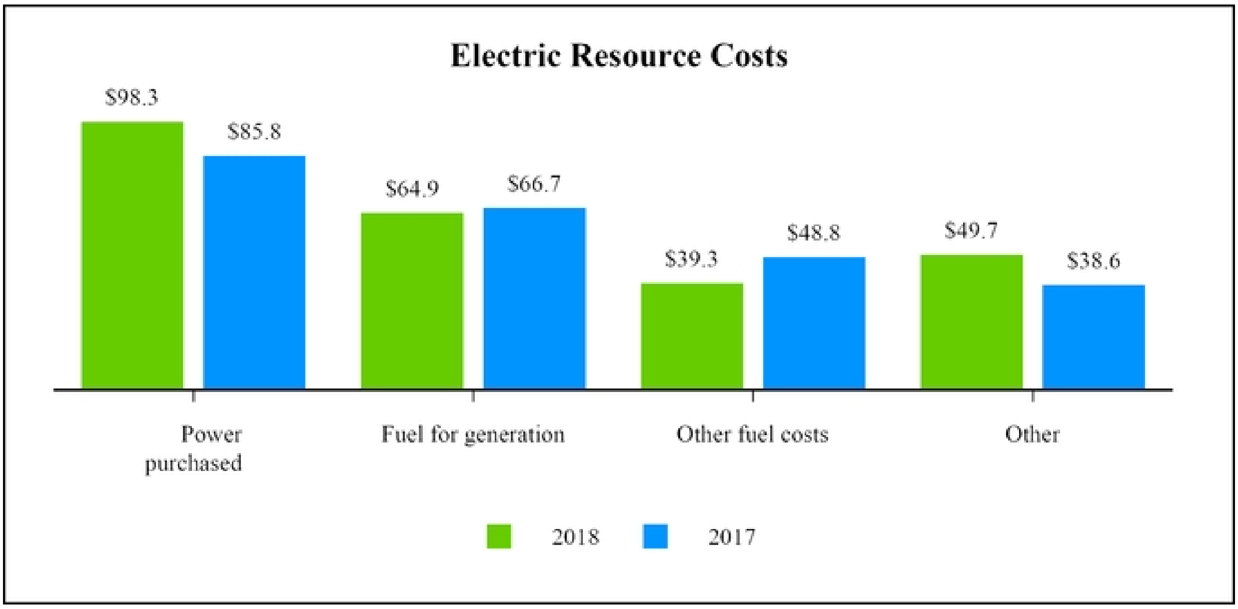
The following table presents Avista Utilities' average number of electric and natural gas retail customers for the nine months ended September 30:

	Electric Customers		Natural Gas Customers	
	2018	2017	2018	2017
Residential	339,331	334,015	313,650	306,389
Commercial	42,520	42,127	35,395	35,174
Interruptible	—	—	39	37
Industrial	1,317	1,330	246	252
Public street and highway lighting	591	567	—	—
Total retail customers	383,759	378,039	349,330	341,852

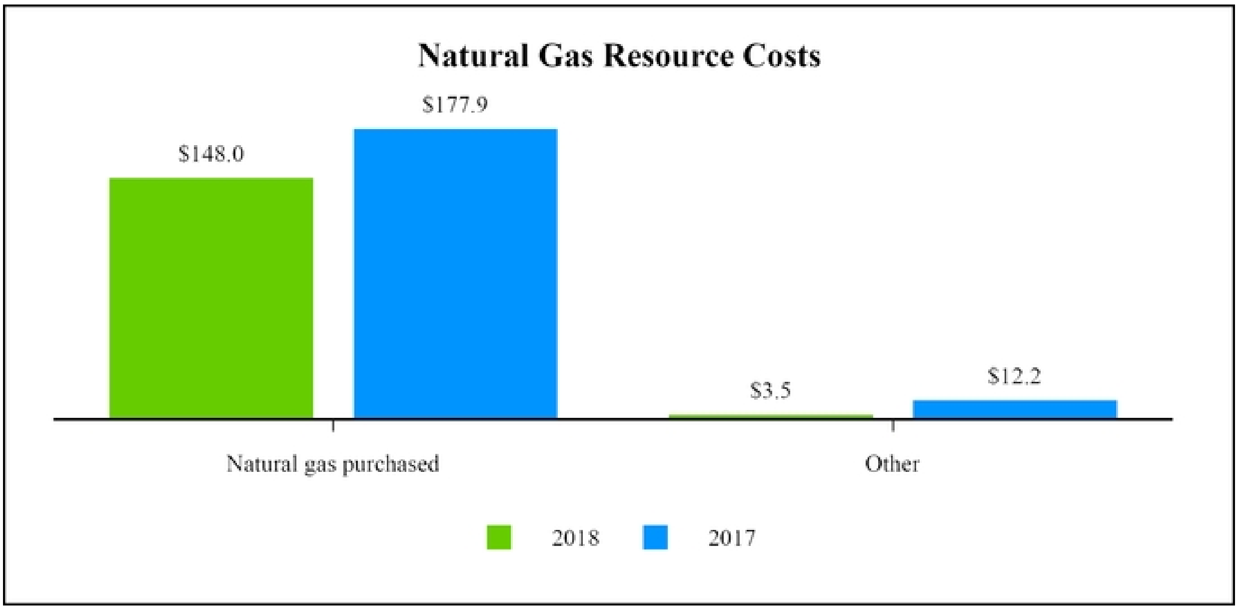
Table of Contents

Utility Resource Costs

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



Total electric resource costs in the graph above include intracompany resource costs of $30.0 million and $36.5 million for the nine months ended September 30, 2018 and September 30, 2017, respectively.



Total natural gas resource costs in the graph above include intracompany resource costs of $20.5 million and $26.9 million for the nine months ended September 30, 2018 and September 30, 2017, respectively.

Total electric resource costs increased $12.3 million for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017 primarily due to the following:

- a $12.5 million increase in purchased power due to an increase in the volume of power purchases (increased costs $13.8 million), partially offset by a decrease in wholesale prices (decreased costs $1.3 million). The fluctuation in volumes and prices was primarily the result of our optimization activities during the period.

- a $1.8 million decrease in fuel for generation primarily due to a decrease in natural gas fuel prices and an outage at Colstrip in the third quarter, partially offset by an overall increase in thermal generation.
- a $9.5 million decrease in other fuel costs.
- a $4.7 million increase from amortizations and deferrals of power costs. This change was primarily the result of lower net power supply costs.
- a $6.4 million increase in other regulatory amortizations and other electric resource costs.

Total natural gas resource costs decreased $38.6 million for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017 primarily due to the following:

- a $29.9 million decrease in natural gas purchased due to a decrease in the price of natural gas (decreased costs $21.4 million) and a decrease in total therms purchased (decreased costs $8.5 million). Total therms purchased decreased due to a decrease in retail sales, partially offset by an increase in wholesale sales.
- a $5.8 million decrease from amortizations and deferrals of natural gas costs.
- a $2.9 million decrease 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 nine months ended September 30 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2018	2017	2018	2017	2018	2017	2018	2017
Operating revenues	$ 730,483	$ 725,695	$ 290,583	$ 330,580	$ (50,541)	$ (63,371)	$ 970,525	$ 992,904
Resource costs	252,232	239,900	151,457	190,061	(50,541)	(63,371)	353,148	366,590
Utility margin	$ 478,251	$ 485,795	$ 139,126	$ 140,519	$ —	$ —	$ 617,377	$ 626,314

Electric utility margin decreased $7.5 million and natural gas utility margin decreased $1.4 million.

The primary reason for the decrease in both electric and natural gas utility margin was federal income tax law changes that lowered the corporate tax rate from 35 percent to 21 percent. As our customers' rates continued to have 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 and June 1, 2018 in Idaho, base rates reflect the lower 21 percent corporate tax, as such, we are no longer deferring the tax rate change in these jurisdictions. There is no impact to our net income as there was a corresponding decrease in income tax expense.

Electric utility margin was positively impacted during 2018 by general rate increases in Idaho (effective January 1, 2018) and Washington (effective May 1, 2018), as well as customer growth. For the nine months ended September 30, 2018, we recognized a pre-tax benefit of $5.6 million under the ERM in Washington compared to a benefit of $3.6 million for the nine months ended September 30, 2017. For the full year of 2018, we expect to be in a benefit position under the ERM within the 90 percent customer/10 percent Company sharing band, primarily due to above normal hydroelectric generation and lower natural gas fuel prices, which allowed us to engage in optimization activities.

Natural gas utility margin was positively impacted by general rate increases in Oregon (effective October 1 and November 1, 2017), Idaho (effective January 1, 2018) and Washington (effective May 1, 2018), as well as 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 below.

Results of Operations - Alaska Electric Light and Power Company

Three months ended September 30, 2018 compared to the three months ended September 30, 2017 and nine months ended September 30, 2018 compared to the nine months ended September 30, 2017

Net income for AEL&P was $0.8 million for the three months ended September 30, 2018 compared to $0.4 million for the three months ended September 30, 2017. Net income was $5.9 million for the nine months ended September 30, 2018 compared to $6.0 million for the nine months ended September 30, 2017.

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

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Operating revenues	$ 9,570	$ 10,864	$ 33,715	$ 38,002
Resource costs	3,058	4,052	8,958	10,315
Utility margin	$ 6,512	$ 6,812	$ 24,757	$ 27,687

Electric revenues decreased for both the third quarter of 2018 and the year-to-date primarily due to the accrual for refunds to customers related to the federal income tax law changes that lowered the corporate tax rate from 35 percent to 21 percent. As of July 31, 2018, AEL&P had recorded a customer refund liability of $1.7 million related to this tax law change, which was returned to customers during August 2018. Effective August 1, 2018, retail rates to customers were reduced to reflect the lower corporate tax rate. For the third quarter and year-to-date there was no impact to net income as there was a corresponding decrease in income tax expense. See "Executive Level Summary" for additional discussion regarding the regulatory proceedings surrounding the tax law change.

In addition, effective January 1, 2018, due to the adoption of ASU No. 2014-09 (revenue recognition standard), AEL&P no longer records utility-related taxes collected from customers on a gross basis in revenue and taxes other than income taxes. These taxes are currently recorded on a net basis within revenue. This change in accounting reduced 2018 revenue, utility margin and taxes other than income taxes by $0.3 million for the third quarter and $1.2 million for the year-to-date as compared to the same periods in 2017 with no impact to net income.

For operating expenses, there was a decrease in other operating expenses for both the third quarter of 2018 and the year-to-date primarily due to a decrease in generation maintenance and supplies expense, partially offset by an increase in distribution maintenance expenses.

Results of Operations - Other Businesses

Net losses for our other businesses were $2.6 million for the three months ended September 30, 2018 compared to a net loss of $1.4 million for the three months ended September 30, 2017. Net losses were $7.0 million for the nine months ended September 30, 2018 compared to $3.2 million for the nine months ended September 30, 2017.

Net losses for the nine months ended September 30, 2018 were primarily related to impairment losses on investments and net losses from our other equity method investments. In addition, we had increased expenses at one of our subsidiaries associated with the insolvency of the general contractor on a renovation project. The general contractor's insolvency resulted in the recording of a liability to various subcontractors. During 2017, we had increased compliance costs at one of our subsidiaries that did not reoccur during 2018, which partially offset the decrease in earnings for the year-to-date 2018 as compared to the year-to-date 2017.

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 2017 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 nine months ended September 30, 2018. See the 2017 Form 10-K for further discussion.

As of September 30, 2018, we had $343.8 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.

Review of Cash Flow Statement

Operating Activities

Net cash provided by operating activities was $365.8 million for the nine months ended September 30, 2018 compared to $307.5 million for the nine months ended September 30, 2017. The increase in net cash provided by operating activities was primarily related to cash collateral posted for derivative instruments. During 2018, our cash collateral posted has decreased by $47.2 million, primarily due to the settlement of derivative interest rate swaps which were in a liability position. We paid a net amount of $26.6 million during the second quarter of 2018 to settle the derivative interest rate swaps. Also, there were favorable fluctuations in the fair value of our outstanding interest rate swaps and energy commodity derivatives, which contributed to the decrease in collateral requirements. This is compared to the first nine months of 2017, which required additional cash collateral to be posted of $1.9 million.

In addition, lower federal income tax rates went into effect on January 1, 2018. As a result, we are paying federal income taxes at 21 percent in 2018 but our customers' rates continued to have a 35 percent corporate income tax rate built into base rates from prior general rate cases. As such, we deferred the difference between the 35 percent income tax rate and the current income tax rate of 21 percent and we recorded a customer refund liability of $17.7 million that will be returned to customers in future periods.

The increases above were partially offset because during the first nine months of 2018 we had decreased net income (after consideration of non-cash items included in net income) of $302.7 million, compared to $326.2 million for the first nine months of 2017.

Investing Activities

Net cash used in investing activities was $307.7 million for the nine months ended September 30, 2018, compared to $302.4 million for the nine months ended September 30, 2017. During the nine months ended September 30, 2018, we paid $296.2 million for utility capital expenditures compared to $287.9 million for the nine months ended September 30, 2017. Also, during 2018, our subsidiaries invested $8.6 million in equity and property, compared to $10.9 million invested during 2017.

Financing Activities

Net cash used by financing activities was $53.1 million for the nine months ended September 30, 2018, compared to $1.0 million provided for the nine months ended September 30, 2017. We had the following transactions:

- net proceeds from the issuance of long-term debt of $374.6 million, which was used to repay maturing long-term debt of $276.8 million and repay the outstanding balance under our committed line of credit during 2018. This was compared to an increase in short-term borrowings of $75.0 million in 2017, and
- cash dividends paid to Avista Corp. shareholders increased to $73.6 million (or $1.1175 per share) for the nine months ended September 30, 2018 from $69.2 million (or $1.0725 per share) for the nine months ended September 30, 2017.

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 September 30, 2018 and December 31, 2017 (dollars in thousands):

	September 30, 2018		December 31, 2017	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt and capital leases	$ 2,629	0.1%	$ 277,438	7.6%
Short-term borrowings	35,000	0.9%	105,398	2.9%
Long-term debt to affiliated trusts	51,547	1.4%	51,547	1.4%
Long-term debt and capital leases	1,860,944	50.3%	1,491,799	40.8%
Total debt	1,950,120	52.7%	1,926,182	52.7%
Total Avista Corporation shareholders’ equity	1,749,552	47.3%	1,729,828	47.3%
Total	$ 3,699,672	100.0%	$ 3,656,010	100.0%

Our shareholders’ equity increased $19.7 million during the first nine months of 2018 primarily due to net income, 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 September 30, 2018, there was $343.8 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 September 30, 2018, we were in compliance with this covenant with a ratio of 52.7 percent.

AEL&P has a $25.0 million committed line of credit that expires in November 2019. As of September 30, 2018, 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 September 30, 2018, AEL&P was in compliance with this covenant with a ratio of 52.1 percent.

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

	2018	2017
Borrowings outstanding at end of period	$ 35,000	$ 195,000
Letters of credit outstanding at end of period	$ 21,230	$ 43,853
Maximum borrowings outstanding during the period	$ 111,000	$ 195,000
Average borrowings outstanding during the period	$ 36,299	$ 123,335
Average interest rate on borrowings during the period	2.43%	1.81%
Average interest rate on borrowings at end of period	2.88%	1.99%

As of September 30, 2018, 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

During 2018, we have issued $375.0 million of long-term debt as discussed above. We do not expect any further long-term debt issuances in 2018. Through early 2019, we expect to raise up to $110.0 million of equity in order to fund planned capital expenditures, maintain an appropriate capital structure and for other general corporate purposes. The $110.0 million of equity may come from the sale of shares through our sales agency agreements or from an equity contribution from Hydro One after consummation of the acquisition or from a combination of those sources.

After considering the issuance of long-term debt and the expected issuance of equity, 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.

2019 and Forward Operating Cash Flows

Due to federal income tax law changes, we expect our operating cash flows will be negatively impacted going forward primarily due to the loss of the bonus depreciation tax deduction and from the timing of the return of excess deferred taxes to customers. As a result, we may need to raise additional capital.

Capital Expenditures

We are making capital investments to enhance service and system reliability for our customers and replace aging infrastructure. Our estimated capital expenditures at Avista Utilities have increased from $405 million to $435 million for 2018 primarily due to additional spending associated with capital for new electric and natural gas services. Our estimates for 2019 and 2020 have not materially changed during the nine months ended September 30, 2018. See the 2017 Form 10-K for further information.

Off-Balance Sheet Arrangements

As of September 30, 2018, we had $21.2 million in letters of credit outstanding under our $400.0 million committed line of credit, compared to $34.4 million as of December 31, 2017.

Pension Plan

Avista Utilities

In the nine months ended September 30, 2018 we contributed $22.0 million to the pension plan and we do not expect any further contributions in 2018. We expect to contribute a total of $110.0 million to the pension plan in the period 2018 through 2022, 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 6 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 nine months ended September 30, 2018 other than the issuance and sale of $375.0 million of 4.35 percent first mortgage bonds due in June 2048 through a public offering. See "Note 9 of the Notes to Condensed Consolidated Financial Statements" for additional discussion of the bond issuance. See the 2017 Form 10-K for our contractual obligations.

Environmental Issues and Contingencies

Our environmental issues and contingencies disclosures have not materially changed during the nine months ended September 30, 2018 other than the following:

Clean Air Act (CAA) - Hazardous Air Pollutants (HAPs)

On April 16, 2016, the Mercury Air Toxic Standards (MATS), an EPA rule for coal and oil-fired sources, became effective for all Colstrip units. We own 15 percent of Colstrip Units 3 & 4.

Colstrip performs compliance assurance stack testing on a quarterly basis to meet the MATS site-wide limitation for Particulate Matter (PM) emissions (0.03 lbs./MMBtu). The Montana Department of Environmental Quality (MDEQ) was notified of a PM emission deviation by Talen, the plant operator, on June 28, 2018 for the testing performed on June 21, 2018. As a result, Unit 3 was immediately removed from service. Similarly, Unit 4 was removed from service on June 29, 2018.

Talen proposed, and the MDEQ acknowledged, that limited operation of Units 3 & 4 for the evaluation of a corrective action and/or data gathering related to potential corrective action was a prudent approach to solving the issue. An extensive inspection was conducted including: the coal supply, coal mills, boiler, combustion, ductwork, air preheater, scrubbers, and the stack. Talen implemented cleaning, adjustments, troubleshooting, testing, and other corrective actions. As a part of the corrective action, new flow balancing plates were installed in all Unit 3 & 4 scrubber vessels to further enhance PM removal efficiency.

PM testing on September 6, 2018 on Unit 4, and September 11, 2018 on Unit 3, demonstrated compliance with the MATS. Both of these compliance tests were witnessed by the MDEQ. With the passing of the PM testing with MATS compliance, Talen returned both Units 3 & 4 to service on September 11, 2018.

Due to the failure to meet the MATS standard, Colstrip Units 3 & 4 are now subject to potential MDEQ enforcement action. The extent of this action is currently under investigation. Due to the complicated nature of the compliance calculation and the various factors that MDEQ may consider, we are unable to anticipate the extent of the impending enforcement action at this time.

Climate Change - Federal Regulatory Actions

On August 31, 2018 the EPA issued a proposed replacement rule to the Clean Power Plan, called the Affordable Clean Energy (ACE) rule. ACE proposes heat rate improvements as the best system of emissions reduction. The proposed rule also includes implementation guidelines for Clean Air Act section 111(d) as well as revisions to the New Source Review program. The proposed rule included a public comment period through October 30, 2018. GHG emission standards could result in significant compliance costs. Such standards could also preclude us from developing, operating or contracting with certain types of generating plants, as well as increase the cost of wholesale electricity. Given these ongoing developments, we cannot at this time predict the outcome or estimate the extent to which our facilities may be impacted by the proposed ACE rule. We intend to seek recovery of costs related to compliance with these requirements through the ratemaking process.

Climate Change - State Legislation and State Regulatory Activities - Washington

Initiative 1631

In the general election held on November 6, 2018, voters in the State of Washington were asked to approve or reject Initiative 1631. As of this filing, the final ballot counts have not been completed for this initiative, nor have there been any preliminary indications of whether this initiative will be approved. This ballot measure would impose a carbon fee based upon the carbon content of transportation and heating fuels along with the carbon content inherent in electricity consumed in the state. If approved, the fee would be imposed at a rate of $15/metric ton beginning on January 1, 2020, and would increase by $2/metric ton annually plus inflation; the $2/metric ton escalator would no longer be applied once the state met its 2035 greenhouse gas emission reduction goal and was deemed on target to meet its 2050 goal. The ballot initiative would allow electric and natural gas utilities, along with other entities, access to carbon fees collected from customers and to expend them pursuant to a clean energy investment plan approved by the WUTC. The implications of this measure on system operations and costs will be more fully assessed in the event it is approved by the voters.

Clean Air Rule

In September 2016, Ecology adopted the Clean Air Rule (CAR) to cap and reduce GHG emissions across the State of Washington in pursuit of the State's GHG goals, which were enacted in 2008 by the Washington State Legislature.

In September 2016, Avista Corp., Cascade Natural Gas Corp., NW Natural and Puget Sound Energy (collectively, Petitioners) jointly filed an action in the U.S. District Court for the Eastern District of Washington challenging Ecology's promulgated CAR. The four companies also filed litigation in Thurston County Superior Court.

The case in the U.S. District Court has been tolled while the state court case proceeds. On December 15, 2017, the Thurston County Superior Court issued a ruling invalidating the CAR. On April 27, 2018, the Superior Court entered its order invalidating the CAR. Ecology has since appealed the ruling, and has requested that the Washington State Supreme Court accept direct review. Both the appeal and Ecology's request for direct review remain pending. Consequently, we cannot predict the outcome of these matters at this time, but plan to seek recovery of costs related to compliance with surviving requirements through the ratemaking process.

See the 2017 Form 10-K for further discussion of environmental issues and contingencies.

Enterprise Risk Management

The material risks to our businesses were discussed in our 2017 Form 10-K and have not materially changed during the nine months ended September 30, 2018. Refer to the 2017 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 nine months ended September 30, 2018. Refer to the 2017 Form 10-K. The financial risks included below are required interim disclosures, even if they have not materially changed from December 31, 2017.

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 5 of the Notes to Condensed Consolidated Financial Statements" for a summary of our interest rate swap derivatives outstanding as of September 30, 2018 and December 31, 2017 and the amount of additional collateral we would have to post in certain circumstances. In addition, see "Regulatory Matters – Washington – 2017 General Rate Cases" for additional discussion of our interest rate risk mitigation plan and the changes recommended by the WUTC.

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 September 30, 2018, we had cash deposited as collateral in the amount of $27.3 million and letters of credit of $17.3 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 2017 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 September 30, 2018, we would potentially be required to post up to $3.8 million of additional collateral. This amount is different from the $1.4 million disclosed in "Note 5 of the Notes to Condensed Consolidated Financial Statements" because, while this analysis includes contracts that are not considered derivatives in addition to the contracts considered in Note 5, this analysis takes into account contractual threshold limits that are not considered in Note 5. Without contractual threshold limits, we would potentially be required to post up to $5.3 million of additional collateral.

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 September 30, 2018, we had interest rate swap derivatives outstanding with a notional amount totaling $195.0 million and we did not have any cash or letters of credit posted 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 September 30, 2018, we would be required to post up to $2.0 million of collateral.

Energy Commodity Risk

Our energy commodity risks have not materially changed during the nine months ended September 30, 2018, except as discussed below. Refer to the 2017 Form 10-K. The following table presents energy commodity derivative fair values as a net asset or (liability) as of September 30, 2018 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 2018	$ (2,089)	$ 1,065	$ 740	$ (8,409)	$ 9	$ (830)	$ 100	$ 3,890
2019	(3,795)	1,113	(604)	(20,643)	15	(934)	(1,362)	9,828
2020	—	—	(819)	(3,857)	—	(728)	(1,052)	69
2021	—	—	—	40	—	—	(585)	47
2022	—	—	—	—	—	—	—	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2017 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)
2018	$ (8,267)	$ (501)	$ 1,022	$ (36,834)	$ 35	$ 4,100	$ (374)	$ 15,829
2019	(4,950)	(1,159)	(570)	(17,814)	(13)	4,621	(932)	6,395
2020	—	—	(766)	(1,882)	—	(194)	(1,050)	—
2021	—	—	—	—	—	—	(655)	—
2022	—	—	—	—	—	—	—	—
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.

Future Resource Needs

In August 2018, we filed our 2018 Natural Gas IRP with the WUTC, the IPUC and the OPUC. The IRP details projected growth in demand for energy and the new resources needed to serve customers over the next 20 years. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project.

Highlights of the 2018 natural gas IRP include the following expectations and/or assumptions:

- We will need no additional natural gas transportation resources during the 20-year planning horizon in Washington, Idaho, or Oregon.
- Due to expected carbon legislation at the state levels through a cap and trade mechanism (Oregon) or a fee mechanism (Washington), we expect natural gas prices to include a carbon price adder in Oregon and Washington, but not in Idaho.
- North American supplies of natural gas will continue to be abundant led by shale gas development.
- Customer growth in our service territory will increase slightly compared to the 2016 IRP. There will be increasing interest from customers to utilize natural gas for heating due to its abundant supply and consequent low cost.
- We anticipate that any increased demand for natural gas regionally will primarily come from power generation as natural gas is increasingly being used to back up solar and wind technology, as well as replace retired coal plants. There is also potential for increased usage in other markets, such as LNG exports or exports to Mexico.
- Slightly higher customer growth will continue to be offset by lower use per customer and an increased amount of demand side management (DSM). The combination of low priced natural gas in addition to carbon fees or other programs has led to a higher potential for DSM measures as compared to the previous three IRP's.
- The availability of natural gas in North America will continue to change global LNG dynamics. Existing and new LNG facilities will look to export low cost North American natural gas to the higher priced foreign markets. This could alter the price of natural gas and/or transportation in U.S. markets, constrain existing pipeline networks, stimulate development of new pipeline resources and change flows of natural gas across North America.

We will monitor these assumptions on an on-going basis and adjust our resource requirements accordingly.

We are required to file a natural gas IRP every two years, with the next IRP expected to be filed during the third quarter of 2020. Our resource strategy in our 2020 IRP may change from the 2018 IRP based on market, legislative and regulatory developments.

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 September 30, 2018.

There have been no changes in the Company's internal control over financial reporting that occurred during the third quarter of 2018 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

Please refer to the 2017 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 2017 Form 10-K, except for the following:

External Mandates Risk

Import tariffs and/or other mandates imposed by the current presidential administration could potentially lead to a trade war with other foreign governments, and could significantly increase the prices on raw materials that are critical to our business, such as steel poles or wires. In addition, tariff increases may have a similar impact to our other suppliers and certain other customers, which could increase the negative impact on our operating results or future cash flows, as well as impact customer rates.

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 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) Not applicable

(b) Not applicable

(c) Not applicable

Dividend Restrictions

The restrictions on the payment of dividends on common stock have not materially changed during the nine months ended September 30, 2018 except for the following:

As a result of the Merger Agreement with Hydro One, Avista Corp. cannot (A) declare, authorize, set aside for payment or pay any dividend on, or make any other distribution in respect of, any shares of its capital stock, other than (1) dividends paid by any Subsidiary of the Company to the Company or to any wholly owned Subsidiary of the Company, (2) quarterly cash dividends with respect to the Company Common Stock not to exceed the current annual per share dividend rate by more than $0.06 per year, with record dates and payment dates consistent with the Company’s current dividend practice, or (3) a “stub period” dividend to holders of record of Company Common Stock as of immediately prior to the Effective Time equal to the product of (x) the number of days from the record date for payment of the last quarterly dividend paid by the Company prior to the Effective Time, multiplied by (y) a daily dividend rate determined by dividing the amount of the last quarterly dividend prior to the Effective Time by ninety-one or (B) adjust, split, combine, subdivide or reclassify any shares of its capital stock.

For further information regarding limitations on the conduct of Avista Corp.'s business under the Merger Agreement, see Section 5 of the Merger Agreement, which was filed as Exhibit 2.1 to Avista Corp.’s Current Report on Form 8-K filed with the SEC on July 19, 2017. See the 2017 Form 10-K for further information on other restrictions on the payment of dividends on common stock.

Item 4. Mine Safety Disclosures

Not applicable.

Item 6. Exhibits

2.1	Agreement and Plan of Merger, dated as of July 19, 2017, by and among Avista Corporation, Hydro One Limited, Olympus Holding Corp. and Olympus Corp. (1)
12	Computation of ratio of earnings to fixed charges (2)
15	Letter Re: Unaudited Interim Financial Information (2)
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) (2)
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) (2)
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) (3)
101	The following financial information from the Quarterly Report on Form 10−Q for the period ended September 30, 2018, formatted in XBRL (Extensible Business Reporting Language) and filed electronically herewith: (i) the Condensed Consolidated Statements of Income; (ii) Condensed Consolidated Statements of Comprehensive Income; (iii) the Condensed Consolidated Balance Sheets; (iv) the Condensed Consolidated Statements of Cash Flows; (v) the Condensed Consolidated Statements of Equity; and (vi) the Notes to Condensed Consolidated Financial Statements. (2)

(1) Previously filed as exhibit 2.1 to the registrant's Current Report on Form 8-K, filed as of July 19, 2017 and incorporated herein by reference.

(2) Filed herewith.

(3) 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: November 6, 2018

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

Exhibit 12

AVISTA CORPORATION

Computation of Ratio of Earnings to Fixed Charges
Consolidated
(Thousands of Dollars)

	Nine months ended	Years Ended December 31				
	September 30, 2018	2017	2016	2015	2014	2013
Fixed charges, as defined:						
Interest charges	$ 75,046	$ 96,067	$ 86,897	$ 80,613	$ 74,025	$ 73,772
Amortization of debt expense and premium - net	2,251	3,167	3,391	3,415	3,635	3,813
Interest portion of rentals	813	1,160	1,324	1,287	1,187	1,146
Total fixed charges	$ 78,110	$ 100,394	$ 91,612	$ 85,315	$ 78,847	$ 78,731
Earnings, as defined:						
Pre-tax income from continuing operations	$ 108,196	$ 198,690	$ 215,402	$ 185,619	$ 192,106	$ 162,347
Add (deduct):						
Capitalized interest	(3,324)	(3,310)	(2,651)	(3,546)	(3,924)	(3,676)
Total fixed charges above	78,110	100,394	91,612	85,315	78,847	78,731
Total earnings	$ 182,982	$ 295,774	$ 304,363	$ 267,388	$ 267,029	$ 237,402
Ratio of earnings to fixed charges	2.34	2.95	3.32	3.13	3.39	3.02

Exhibit 15

November 6, 2018

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 September 30, 2018 and 2017, as indicated in our report dated November 6, 2018; 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 September 30, 2018, 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. 333-209714 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: November 6, 2018

/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: November 6, 2018

/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 September 30, 2018 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: November 6, 2018

/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