

AVISTA CORP
Form 10-Q
November 01, 2017

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

Form 10-Q
(Mark One)

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

FOR THE QUARTERLY PERIOD ENDED September 30, 2017 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 (I.R.S. Employer
incorporation or organization) 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 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 No

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

Large accelerated filer Accelerated filer

Non-accelerated filer (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

As of October 30, 2017, 64,415,157 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

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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,” “p” 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 (temperatures, precipitation levels and wind patterns), which affect both energy demand and electric generating capability, including the effect of precipitation and temperature on hydroelectric resources, the effect of wind patterns on wind-generated power, weather-sensitive customer demand, and similar effects 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 and/or conservation measures;

changes in the long-term global and our utilities' service area climates, 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 and commodity costs and discretion over allowed return on investment;

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possibility that our integrated resource plans for electric and natural gas will not be acknowledged by the state commissions, which could result in future resource acquisitions based on the integrated resource plans, which are later deemed imprudent;

Energy Commodity Risk

volatility and illiquidity in wholesale energy markets, including 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 counterparties 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 affecting our ability to utilize or resulting in the obsolescence of our power supply resources;

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;

wildfires caused by our electric transmission or distribution systems that may result in injuries to the public or property damage;

injuries to the public or damage arising from or allegedly arising from our operations;

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 receptacles 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 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 extensive cost of replacement power (diesel);

changing river regulation at hydroelectric facilities not owned by us, which could impact our hydroelectric facilities downstream;

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;

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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 the introduction of new technology that may create new cyber security risk;

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 business practices, whether true or not, which could 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;

non-regulated activities may increase earnings volatility;

failure to complete the proposed acquisition could negatively impact the market price of Avista Corp.'s common stock or result in termination fees that could have a material adverse effect on our results of operations, financial condition, and cash flows;

the proposed acquisition of the Company by Hydro One has resulted in multiple shareholder class action lawsuits against the Company and its board of directors that could have a material adverse effect on our results of operations, financial condition, and cash flows and could delay or preclude consummation of the transaction;

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 of 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;

policy and/or legislative changes resulting from the new presidential administration in various regulated areas, including, but not limited to, potential tax reform, environmental regulation and healthcare 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

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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 at our website as soon as practicable after electronically filing these reports with the U.S. Securities and Exchange Commission (SEC). Information contained on our website is not part of this report.

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PART I. Financial Information

Item 1. Condensed Consolidated Financial Statements

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

Dollars in thousands, except per share amounts

(Unaudited)

	Three months ended		Nine months ended	
	September 30,		September 30,	
	2017	2016	2017	2016
Operating Revenues:				
Utility revenues	\$291,640	\$296,989	\$1,030,906	\$1,022,670
Non-utility revenues	5,456	6,360	17,161	17,690
Total operating revenues	297,096	303,349	1,048,067	1,040,360
Operating Expenses:				
Utility operating expenses:				
Resource costs	108,568	118,737	376,905	390,271
Other operating expenses	77,784	75,160	232,959	229,605
Acquisition costs	6,730	—	8,004	—
Depreciation and amortization	42,968	40,240	127,596	119,110
Taxes other than income taxes	23,269	22,669	79,733	74,669
Non-utility operating expenses:				
Other operating expenses	6,598	6,756	19,863	18,862
Depreciation and amortization	137	193	482	573
Total operating expenses	266,054	263,755	845,542	833,090
Income from operations	31,042	39,594	202,525	207,270
Interest expense	23,955	21,632	71,170	64,223
Interest expense to affiliated trusts	216	164	601	456
Capitalized interest	(899)	(507)	(2,513)	(2,258)
Other income-net	(1,841)	(1,562)	(6,598)	(7,025)
Income before income taxes	9,611	19,867	139,865	151,874
Income tax expense	5,153	7,606	51,548	54,661
Net income	4,458	12,261	88,317	97,213
Net loss (income) attributable to noncontrolling interests	(7)	(27)	21	(76)
Net income attributable to Avista Corp. shareholders	\$4,451	\$12,234	\$88,338	\$97,137
Weighted-average common shares outstanding (thousands), basic	64,412	63,857	64,392	63,282
Weighted-average common shares outstanding (thousands), diluted	64,892	64,325	64,638	63,687
Earnings per common share attributable to Avista Corp. shareholders:				
Basic	\$0.07	\$0.19	\$1.37	\$1.53
Diluted	\$0.07	\$0.19	\$1.37	\$1.53
Dividends declared per common share	\$0.3575	\$0.3425	\$1.0725	\$1.0275

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation
Dollars in thousands
(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
Net income	\$4,458	\$12,261	\$88,317	\$97,213
Other Comprehensive Income (Loss):				
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of \$98, \$75, \$295 and \$(512) respectively	182	140	548	(949)
Total other comprehensive income (loss)	182	140	548	(949)
Comprehensive income	4,640	12,401	88,865	96,264
Comprehensive loss (income) attributable to noncontrolling interests	(7)	(27)	21	(76)
Comprehensive income attributable to Avista Corporation shareholders	\$4,633	\$12,374	\$88,886	\$96,188

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation
Dollars in thousands
(Unaudited)

	September 30, 2017	December 31, 2016
Assets:		
Current Assets:		
Cash and cash equivalents	\$14,716	\$8,507
Accounts and notes receivable-less allowances of \$4,838 and \$5,026, respectively	125,595	180,265
Regulatory asset for energy commodity derivatives	22,005	11,365
Materials and supplies, fuel stock and stored natural gas	65,961	53,314
Income taxes receivable	42,111	48,265
Other current assets	46,246	49,625
Total current assets	316,634	351,341
Net Utility Property:		
Utility plant in service	5,686,633	5,506,499
Construction work in progress	194,679	150,474
Total	5,881,312	5,656,973
Less: Accumulated depreciation and amortization	1,578,148	1,509,473
Total net utility property	4,303,164	4,147,500
Other Non-current Assets:		
Investment in affiliated trusts	11,547	11,547
Goodwill	57,672	57,672
Other property and investments-net and other non-current assets	80,022	72,224
Total other non-current assets	149,241	141,443
Deferred Charges:		
Regulatory assets for deferred income tax	123,449	109,853
Regulatory assets for pensions and other postretirement benefits	230,988	240,114
Other regulatory assets	129,112	135,751
Regulatory asset for interest rate swaps	170,079	161,508
Non-current regulatory asset for energy commodity derivatives	16,371	16,919
Other deferred charges	13,194	5,326
Total deferred charges	683,193	669,471
Total assets	\$5,452,232	\$5,309,755

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation
Dollars in thousands
(Unaudited)

	September 30, 2017	December 31, 2016
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	\$72,777	\$115,545
Current portion of long-term debt and capital leases	277,626	3,287
Short-term borrowings	106,298	120,000
Energy commodity derivative liabilities	11,054	7,035
Accrued interest	29,077	15,869
Accrued taxes other than income taxes	34,520	33,374
Deferred natural gas costs	34,399	30,820
Current portion of pensions and other postretirement benefits	11,544	10,994
Current interest rate swap derivative liabilities	34,520	6,025
Other current liabilities	61,436	64,579
Total current liabilities	673,251	407,528
Long-term debt and capital leases	1,491,789	1,678,717
Long-term debt to affiliated trusts	51,547	51,547
Regulatory liability for utility plant retirement costs	284,263	273,983
Pensions and other postretirement benefits	216,464	226,552
Deferred income taxes	903,943	840,928
Non-current interest rate swap derivative liabilities	1,330	28,705
Other non-current liabilities, regulatory liabilities and deferred credits	158,699	153,319
Total liabilities	3,781,286	3,661,279
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; 64,414,572 and 64,187,934 shares issued and outstanding as of September 30, 2017 and December 31, 2016, respectively	1,077,215	1,075,281
Accumulated other comprehensive loss	(7,020) (7,568
Retained earnings	600,132	581,014
Total Avista Corporation shareholders' equity	1,670,327	1,648,727
Noncontrolling Interests	619	(251
Total equity	1,670,946	1,648,476
Total liabilities and equity	\$5,452,232	\$5,309,755
The Accompanying Notes are an Integral Part of These Statements.		

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CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

For the Nine Months Ended September 30

Dollars in thousands

(Unaudited)

	2017	2016
Operating Activities:		
Net income	\$88,317	\$97,213
Non-cash items included in net income:		
Depreciation and amortization	130,803	122,414
Deferred income tax provision and investment tax credits	58,242	87,246
Power and natural gas cost amortizations, net	8,416	11,422
Amortization of debt expense	2,440	2,595
Amortization of investment in exchange power	1,838	1,838
Stock-based compensation expense	5,809	6,261
Equity-related Allowance for Funds Used During Construction (AFUDC)	(5,012)	(6,306)
Pension and other postretirement benefit expense	27,816	29,076
Amortization of Spokane Energy contract	—	10,904
Other regulatory assets and liabilities and deferred debits and credits	(12,683)	(20,215)
Change in decoupling regulatory deferral	20,193	(24,693)
Other	(190)	5,052
Contributions to defined benefit pension plan	(22,000)	(12,000)
Cash paid for settlement of interest rate swap agreements	(11,302)	(53,966)
Cash received for settlement of interest rate swap agreements	2,479	—
Changes in certain current assets and liabilities:		
Accounts and notes receivable	52,534	53,726
Materials and supplies, fuel stock and stored natural gas	(12,653)	(3,932)
Collateral posted for derivative instruments	(1,896)	(19,754)
Income taxes receivable	(4,254)	(25,222)
Other current assets	(16)	(8,486)
Accounts payable	(29,992)	(17,206)
Other current liabilities	8,624	18,151
Net cash provided by operating activities	307,513	254,118
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(287,853)	(288,072)
Issuance of notes receivable at subsidiaries	(2,800)	(9,718)
Equity and property investments made by subsidiaries	(10,899)	(8,741)
Distributions received from investments	1,915	—
Other	(2,714)	(8,422)
Net cash used in investing activities	(302,351)	(314,953)

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

For the Nine Months Ended September 30

Dollars in thousands

(Unaudited)

	2017	2016
Financing Activities:		
Net increase in short-term borrowings	\$75,000	\$82,000
Proceeds from issuance of long-term debt	—	70,000
Maturity of long-term debt and capital leases	(2,465)	(92,375)
Issuance of common stock, net of issuance costs	1,490	66,756
Cash dividends paid	(69,220)	(65,172)
Other	(3,758)	(3,774)
Net cash provided by financing activities	1,047	57,435
Net increase (decrease) in cash and cash equivalents	6,209	(3,400)
Cash and cash equivalents at beginning of period	8,507	10,484
Cash and cash equivalents at end of period	\$14,716	\$7,084

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

Avista Corporation

For the Nine Months Ended September 30

Dollars in thousands

(Unaudited)

	2017	2016
Common Stock, Shares:		
Shares outstanding at beginning of period	64,187,934	62,312,651
Shares issued	226,638	1,869,836
Shares outstanding at end of period	64,414,572	64,182,487
Common Stock, Amount:		
Balance at beginning of period	\$1,075,281	\$1,004,336
Equity compensation expense	5,055	5,462
Issuance of common stock, net of issuance costs	1,490	66,756
Payment of minimum tax withholdings for share-based payment awards	(3,420)	(3,073)
Purchase of subsidiary noncontrolling interests	(1,191)	—
Balance at end of period	1,077,215	1,073,481
Accumulated Other Comprehensive Loss:		
Balance at beginning of period	(7,568)	(6,650)
Other comprehensive income (loss)	548	(949)
Balance at end of period	(7,020)	(7,599)
Retained Earnings:		
Balance at beginning of period	581,014	530,940
Net income attributable to Avista Corporation shareholders	88,338	97,137
Cash dividends paid on common stock	(69,220)	(65,172)
Balance at end of period	600,132	562,905
Total Avista Corporation shareholders' equity	1,670,327	1,628,787
Noncontrolling Interests:		
Balance at beginning of period	(251)	(339)
Net income (loss) attributable to noncontrolling interests	(21)	76
Purchase of subsidiary noncontrolling interests	891	—
Balance at end of period	619	(263)
Total equity	\$1,670,946	\$1,628,524

The Accompanying Notes are an Integral Part of These Statements.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

The accompanying condensed consolidated financial statements of Avista Corporation (Avista Corp. or the Company) as of and for the interim periods ended September 30, 2017 and September 30, 2016 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 accounting principles generally accepted in the United States of America (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, 2016 (2016 Form 10-K). Please refer to the section "Acronyms and Terms" in the 2016 Form 10-K for definitions of certain terms not defined herein. The acronyms and terms are an integral part of these condensed consolidated financial statements.

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 the 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.

Alaska Energy and Resources Company (AERC) is a wholly-owned subsidiary of Avista Corp. The primary subsidiary of AERC is Alaska Electric Light and Power Company (AEL&P), which comprises Avista Corp.'s regulated utility operations in Alaska. Avista Capital, Inc. (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.

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 Limited (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 in the second half of 2018. See Note 13 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.

Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on income. These taxes are generally based on revenues or the value of property. Utility-related taxes collected from customers (primarily state excise taxes and city utility taxes) are recorded as operating revenue and expense. Taxes other than income taxes consisted of the following items for the three and nine months ended September 30 (dollars in thousands):

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	Three months ended September 30, 2017		Nine months ended September 30, 2016	
Utility-related taxes	\$ 12,663	\$ 12,095	\$ 47,799	\$ 43,033
Property taxes	9,991	10,047	29,829	29,757
Other taxes	615	527	2,105	1,879
Total	\$ 23,269	\$ 22,669	\$ 79,733	\$ 74,669

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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 net realizable value for our non-regulated operations and consisted of the following as of September 30, 2017 and December 31, 2016 (dollars in thousands):

	September 30, 2017	December 31, 2016
Materials and supplies	\$ 41,518	\$ 40,700
Fuel stock	5,064	4,585
Stored natural gas	19,379	8,029
Total	\$ 65,961	\$ 53,314

Derivative Assets and Liabilities

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

The Washington Utilities and Transportation Commission (UTC) and the Idaho Public Utilities Commission (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 Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rate cases. The resulting regulatory assets 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.

As of September 30, 2017, 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 8 for the Company's fair value disclosures.

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Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax, consisted of the following as of September 30, 2017 and December 31, 2016 (dollars in thousands):

	September 30, 2017	December 31, 2016
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of \$3,780 and \$4,075, respectively	\$ 7,020	\$ 7,568

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

Details about Accumulated Other Comprehensive Loss Components	Amounts Reclassified from Accumulated Other Comprehensive Loss				Affected Line Item in Statement of Income
	Three months ended September 30,		Nine months ended September 30,		
	2017	2016	2017	2016	
Amortization of defined benefit pension items					
Amortization of net prior service cost	\$(300)	\$(312)	\$(898)	\$(934)	(a)
Amortization of net loss	3,637	3,642	\$10,913	\$10,926	(a)
Adjustment due to effects of regulation	(3,057)	(3,115)	(9,172)	(11,453)	(a) (b)
	280	215	843	(1,461)	Total before tax
	(98)	(75)	(295)	512	Tax benefit (expense)
	\$182	\$140	\$548	\$(949)	Net of tax

(a) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 4 for additional details).

The adjustment for the effects of regulation during the nine months ended September 30, 2016 includes (b) approximately \$2.1 million related to the reclassification of a pension regulatory asset associated with one of our jurisdictions into accumulated other comprehensive loss.

Effective Income Tax Rate

For the three months ended September 30, 2017 and 2016, the Company's effective tax rate was 53.6 percent and 38.3 percent, respectively. For the nine months ended September 30, 2017 and 2016, the Company's effective tax rate was 36.9 percent and 36.0 percent, respectively. The effective tax rate increased during 2017 because the majority of acquisition costs, which reduce income before income taxes, are not deductible for tax purposes and thus do not reduce income tax expense.

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, 2017, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 11 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)"

In May 2014, the FASB issued 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 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. This ASU is effective for periods beginning after December 15, 2017.

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The Company has a revenue recognition standard implementation team that is working through the implementation process. The Company has evaluated this standard and is planning to adopt this standard in 2018 upon its effective date. The Company is expecting to use a modified retrospective method of adoption, which would require a cumulative adjustment to opening retained earnings, as opposed to a full retrospective application. Based on work performed to date, the Company has not identified any material cumulative adjustments necessary.

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 a significant change in operating revenues or net income. The Company has reviewed and analyzed certain contracts with customers (most of which are related to wholesale sales of power and natural gas) and has not yet identified any significant differences in revenue recognition between current GAAP and ASU No. 2014-09.

During the implementation process, the Company has identified several issues, the most significant of which are as follows based on our current assessment:

Contributions in Aid of Construction – There was the potential that contributions in aid of construction (CIACs) could be recognized as revenue upon the adoption of ASU No. 2014-09. Under current GAAP, CIACs are accounted for as an offset to the cost of utility plant in service. Current implementation guidance indicates that CIACs will continue to be accounted for as an offset to utility plant in service.

Utility-Related Taxes Collected from Customers – There were questions on the presentation of utility-related taxes collected from customers (primarily state excise taxes and city utility taxes) on a gross basis. Under current GAAP, the Company is allowed to record these utility-related taxes on a gross basis in revenue when billed to customers with an offset included in taxes other than income taxes in operating expenses. The Company evaluated whether this gross presentation is appropriate under ASU 2014-09 and the Company's assessment indicates that there will be no material changes to current presentation.

Renewable Energy Credits - Current utility industry implementation guidance indicates that revenue associated with the sale of self-generated renewable energy credits (REC) will be 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 (WREGIS), which generally occurs during a period subsequent to the sale. This represents a change from the Company's current practice, which is to defer revenue recognition until the time of certification. Revenue associated with the sale of RECs is not material to the financial statements; therefore, this change will not materially impact the amount of revenue recognized each period. Additionally, almost all of the Company's REC revenue is deferred for future rebate to retail customers. As such, any change in the timing of revenue recognition would not have any material impact on net income.

The Company is monitoring utility industry implementation guidance as it relates to the above issues to determine if there will be a final industry consensus regarding accounting and presentation of these items.

In addition to the issues described above, the Company also expects significant changes to its revenue-related footnote disclosures, including the bifurcation of wholesale revenue into derivative and non-derivative sales. The Company continues to evaluate what information would be most useful for users of the financial statements, including information already provided elsewhere in the document outside the footnote disclosures. These additional disclosures could include the disaggregation of revenues by type of service, source of revenue or customer class. Also, the Company expects enhanced disclosures regarding its revenue recognition policies and elections.

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. Upon adoption, this ASU must be applied using a modified retrospective approach to the earliest period presented, which will likely require restatements of previously issued financial statements. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. The Company evaluated this standard and determined that it will most likely not early adopt this standard before its effective date in 2019.

The Company has formed a lease standard implementation team that is working through the implementation process. Based on work to-date, the implementation team has identified a complete population of existing and potential leases under the new

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standard and has completed its review of the agreements associated with this population. However, the team has not yet quantified the impact of recording these leases. In addition, the team is developing a process to identify any new potential leases that may be entered into between now and the standard implementation date in 2019.

The Company is monitoring utility industry implementation guidance as it relates to several unresolved issues to determine if there will be an industry consensus, including whether right-of-ways are considered leases. The Company has not yet estimated the potential impact on its future financial condition, results of operations and cash flows.

ASU No. 2016-09 “Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting”

In March 2016, the FASB issued ASU No. 2016-09. This ASU simplified several aspects of the accounting for employee share-based payment transactions including:

- allowing excess tax benefits or tax deficiencies to be recognized as income tax benefits or expenses in the Condensed Consolidated Statements of Income rather than in Additional Paid in Capital (APIC),
- excess tax benefits no longer represent a financing cash inflow on the Condensed Consolidated Statements of Cash Flows and instead will be included as an operating activity,
- requiring excess tax benefits and tax deficiencies to be excluded from the calculation of diluted earnings per share, whereas under previous accounting guidance, these amounts had to be estimated and included in the calculation,
- allowing forfeitures to be accounted for as they occur, instead of estimating forfeitures, and
- changing the statutory tax withholding requirements for share-based payments.

The Company early adopted this standard during the second quarter of 2016, with a retrospective effective date of January 1, 2016. The adoption of this standard resulted in a recognized income tax benefit of \$1.6 million in 2016 associated with excess tax benefits on settled share-based employee payments.

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

In March 2017, the FASB issued ASU No. 2017-07, which amends the income statement presentation of the components of net period benefit cost for an entity’s defined benefit pension and other postretirement plans. Under current GAAP, net benefit cost consists of several components that reflect different aspects of an employer’s financial arrangements as well as the cost of benefits earned by employees. These components are 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 current practice, under which entities capitalize the aggregate net benefit cost to utility plant when applicable, in accordance with Federal Energy and Regulatory Commission (FERC) accounting guidance. Avista Corp. is a rate-regulated entity and all components of net benefit cost are currently recovered from rate payers as a component of utility plant and, under the new ASU, these costs will continue to be recovered from rate payers 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 plant for GAAP will be recorded as regulatory assets.

This ASU is effective for periods beginning after December 15, 2017 and early adoption is permitted. 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. The Company did not early adopt this standard and does not expect a material impact on its future financial condition, results of operations or cash flows upon adoption of this standard.

NOTE 3. DERIVATIVES AND RISK MANAGEMENT

The disclosures below in Note 3 apply only to Avista Corp. and its operating division Avista Utilities; AERC and its primary subsidiary AEL&P do not enter into derivative instruments.

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

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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. Avista Corp. transacts in wholesale markets by selling and purchasing 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, 2017 that are expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

Year	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
	Physical	Financial	Physical	Financial	Physical	Financial	Physical	Financial
	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	MWh	MWh	mmBTUs	mmBTUs	MWh	MWh	mmBTUs	mmBTUs
Remainder 2017	191	303	5,018	33,165	160	367	1,519	17,878
2018	418	763	3,040	90,750	223	1,275	2,177	63,625
2019	235	737	610	44,290	158	982	1,345	30,050
2020	—	—	910	7,750	—	246	1,430	—
2021	—	—	—	—	—	—	1,049	—
Thereafter	—	—	—	—	—	—	—	—

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The following table presents the underlying energy commodity derivative volumes as of December 31, 2016 that are expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

Year	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
	Physical	Financial	Physical	Financial	Physical	Financial	Physical	Financial
	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	MWh	MWh	mmBTUs	mmBTUs	MWh	MWh	mmBTUs	mmBTUs
2017	510	907	15,475	110,380	316	1,552	4,165	73,110
2018	397	—	—	52,755	286	1,244	1,360	15,113
2019	235	—	610	29,475	158	982	1,345	4,020
2020	—	—	910	2,725	—	—	1,430	—
2021	—	—	—	—	—	—	1,060	—
Thereafter	—	—	—	—	—	—	—	—

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 recovery mechanisms (ERM, PCA, and Purchased Gas Adjustments (PGA)), or in the general rate case process, and are expected to be collected through retail rates from customers.

Foreign Currency Exchange Derivatives

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

The following table summarizes the foreign currency exchange derivatives that Avista Corp. has outstanding as of September 30, 2017 and December 31, 2016 (dollars in thousands):

	September 30, 2017	December 31, 2016
Number of contracts	19	21
Notional amount (in United States dollars)	\$ 3,198	\$ 2,819
Notional amount (in Canadian dollars)	3,925	3,754

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.

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The following table summarizes the unsettled interest rate swap derivatives that Avista Corp. has outstanding as of September 30, 2017 and December 31, 2016 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
September 30, 2017	14	\$275,000	2018
	6	70,000	2019
	3	30,000	2020
	1	15,000	2021
	5	60,000	2022
December 31, 2016	6	\$75,000	2017
	14	275,000	2018
	6	70,000	2019
	2	20,000	2020
	5	60,000	2022

During the third quarter 2017, in connection with the pricing of \$90.0 million of Avista Corp. first mortgage bonds that are expected to be issued in December 2017 (see Note 6), the Company cash-settled five interest rate swap derivatives (notional aggregate amount of \$60.0 million) and paid a net amount of \$8.8 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 the Company'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. Upon settlement of interest rate swaps, the cash payments made or received are recorded as a regulatory asset or liability and are amortized as a component of interest expense over the life of the associated debt. The settled interest rate swaps are also included as a part of the Company's cost of debt calculation for ratemaking purposes.

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Summary of Outstanding Derivative Instruments

The amounts recorded on the Condensed Consolidated Balance Sheet as of September 30, 2017 and December 31, 2016 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, 2017 (in thousands):

Derivative and Balance Sheet Location	Fair Value as of September 30, 2017			Net Asset (Liability) on Balance Sheet
	Gross Asset	Gross Liability	Collateral Netted	
Foreign currency exchange derivatives				
Other current liabilities	\$—	\$(51)	\$—	\$(51)
Interest rate swap derivatives				
Other current assets	2,637	(249)	—	2,388
Other property and investments-net and other non-current assets	5,346	(1,896)	—	3,450
Current interest rate swap derivative liabilities	—	(63,074)	28,554	(34,520)
Non-current interest rate swap derivative liabilities	—	(7,136)	5,806	(1,330)
Energy commodity derivatives				
Other current assets	197	(70)	—	127
Current energy commodity derivative liabilities	23,904	(46,036)	11,078	(11,054)
Other non-current liabilities, regulatory liabilities and deferred credits	13,891	(30,262)	4,569	(11,802)
Total derivative instruments recorded on the balance sheet	\$45,975	\$(148,774)	\$ 50,007	\$(52,792)

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of December 31, 2016 (in thousands):

Derivative and Balance Sheet Location	Fair Value as of December 31, 2016			Net Asset (Liability) on Balance Sheet
	Gross Asset	Gross Liability	Collateral Netted	
Foreign currency exchange derivatives				
Other current liabilities	\$5	\$(28)	\$—	\$(23)
Interest rate swap derivatives				
Other current assets	3,393	—	—	3,393
Other property and investments-net and other non-current assets	5,754	(397)	—	5,357
Current interest rate swap derivative liabilities	—	(15,756)	9,731	(6,025)
Non-current interest rate swap derivative liabilities	3,951	(57,825)	25,169	(28,705)
Energy commodity derivatives				
Other current assets	18,682	(16,787)	—	1,895
Current energy commodity derivative liabilities	16,335	(29,598)	6,228	(7,035)
Other non-current liabilities, regulatory liabilities and deferred credits	13,071	(29,990)	3,630	(13,289)
Total derivative instruments recorded on the balance sheet	\$61,191	\$(150,381)	\$ 44,758	\$(44,432)
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

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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, 2017 and December 31, 2016 (in thousands):

	September 30, 2017	December 31, 2016
Energy commodity derivatives		
Cash collateral posted	\$ 19,570	\$ 17,134
Letters of credit outstanding	31,500	24,400
Balance sheet offsetting (cash collateral against net derivative positions)	15,647	9,858
Interest rate swap derivatives		
Cash collateral posted	34,360	34,900
Letters of credit outstanding	6,000	3,600
Balance sheet offsetting (cash collateral against net derivative positions)	34,360	34,900

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, 2017 and December 31, 2016 (in thousands):

	September 30, 2017	December 31, 2016
Energy commodity derivatives		
Liabilities with credit-risk-related contingent features	\$ 670	\$ 1,124
Additional collateral to post	670	1,046
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	72,355	73,978
Additional collateral to post	12,730	21,100

NOTE 4. 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, 2017. 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, 2017 and does not expect any further contributions during 2017. The Company contributed \$12.0 million in cash to the pension plan in 2016.

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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 Post-retirement Benefits	
	2017	2016	2017	2016
Three months ended September 30:				
Service cost	\$5,092	\$4,567	\$ 799	\$ 806
Interest cost	6,976	6,895	1,374	1,530
Expected return on plan assets	(7,900)	(6,887)	(475)	(465)
Amortization of prior service cost	—	1	(274)	(300)
Net loss recognition	2,517	2,161	1,168	1,453
Net periodic benefit cost	\$6,685	\$6,737	\$ 2,592	\$ 3,024
Nine months ended September 30:				
Service cost	\$15,226	\$13,655	\$ 2,422	\$ 2,389
Interest cost	20,903	20,695	4,147	4,623
Expected return on plan assets	(23,700)	(20,512)	(1,425)	(1,415)
Amortization of prior service cost	—	1	(898)	(924)
Net loss recognition	7,380	6,252	3,761	4,312
Net periodic benefit cost	\$19,809	\$20,091	\$ 8,007	\$ 8,985

Total net periodic benefit 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 other operating expenses.

NOTE 5. 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.

Borrowings 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, 2017 and December 31, 2016 (dollars in thousands):

	September 30, 2017	December 31, 2016
Borrowings outstanding at end of period (1)	\$195,000	\$120,000
Letters of credit outstanding at end of period	\$43,853	\$34,353
Average interest rates at end of period	1.99 %	1.50 %

(1) As of September 30, 2017, there was \$195.0 million outstanding under the committed line of credit; however, \$105.9 million was classified as short-term borrowings and the remaining \$89.1 million was classified as long-term debt on the Condensed Consolidated Balance Sheet due to the Company's intention to refinance such amount on a long-term basis through the issuance and sale of first mortgage bonds in December 2017 pursuant to a bond purchase agreement entered into in September 2017. See Note 7 for further discussion of the bond purchase agreement and the refinancing of short-term debt on a long-term basis. In addition, there were short-term borrowings outstanding as of September 30, 2017 on the Condensed Consolidated Balance Sheet related to a

short-term note payable by a subsidiary for the acquisition of land that is expected to be repaid in early 2018.
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, 2017 and December 31, 2016, 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

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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 6. LONG-TERM DEBT AND CAPITAL LEASES

The following details long-term debt outstanding as of September 30, 2017 and December 31, 2016 (dollars in thousands):

Maturity Year	Description	Interest Rate	September 30, 2017	December 31, 2016
Avista Corp. Secured Long-Term Debt				
2018	First Mortgage Bonds	5.95%	\$ 250,000	\$ 250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	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
2051	First Mortgage Bonds	3.54%	175,000	175,000
	Total Avista Corp. secured long-term debt		1,621,700	1,621,700
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		1,696,700	1,696,700
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		1,711,700	1,711,700
Other Long-Term Debt Components				
	Capital lease obligations		62,969	65,435
	Unamortized debt discount		(668)	(792)
	Unamortized long-term debt issuance costs		(9,986)	(10,639)
	Committed line of credit to be refinanced on a long-term basis (2)		89,100	—
	Total		1,853,115	1,765,704
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Current portion of long-term debt and capital leases		(277,626)	(3,287)
	Total long-term debt and capital leases		\$ 1,491,789	\$ 1,678,717

(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

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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 Consolidated Balance Sheets.

In September 2017, the Company entered into a bond purchase agreement with four institutional investors in the private placement market for the issuance and sale of \$90.0 million of Avista Corp. first mortgage bonds in December 2017. The first mortgage bonds will bear a coupon rate of 3.91 percent and mature in December 2047. The Company intends to use the \$90.0 million of bond proceeds, less issuance costs, to refinance on a long-term (2) basis \$89.1 million outstanding under the Company's committed line of credit. As such, \$89.1 million has been excluded from current liabilities and is recorded as long-term debt on the Condensed Consolidated Balance Sheets as of September 30, 2017. In connection with the pricing of the first mortgage bonds, the Company cash-settled five interest rate swap derivatives (notional aggregate amount of \$60.0 million) and paid a net amount of \$8.8 million.

NOTE 7. 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, 2017 and the year ended December 31, 2016:

	September 30, 2017		December 31, 2016	
Low distribution rate	1.81	%	1.29	%
High distribution rate	2.19	%	1.81	%
Distribution rate at the end of the period	2.19	%	1.81	%

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued \$1.5 million of Common Trust Securities to the Company. These debt 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 8. 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

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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, 2017 and December 31, 2016 (dollars in thousands):

	September 30, 2017		December 31, 2016	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	\$951,000	\$1,072,557	\$951,000	\$1,048,661
Long-term debt (Level 3)	677,000	704,130	677,000	675,251
Snettisham capital lease obligation (Level 3)	60,349	62,000	62,160	62,800
Long-term debt to affiliated trusts (Level 3)	51,547	41,238	51,547	38,660

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 80.00 to 129.64, 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, 2017.

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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, 2017 and December 31, 2016 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, 2017					
Assets:					
Energy commodity derivatives	\$—	\$37,902	\$—	\$ (37,775)	\$127
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	90	(90)	—
Interest rate swap derivatives	—	7,983	—	(2,145)	5,838
Deferred compensation assets:					
Fixed income securities (2)	1,692	—	—	—	1,692
Equity securities (2)	6,276	—	—	—	6,276
Total	\$7,968	\$45,885	\$90	\$ (40,010)	\$13,933
Liabilities:					
Energy commodity derivatives	\$—	\$56,013	\$—	\$ (53,422)	\$2,591
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	3,689	(90)	3,599
Power exchange agreement	—	—	16,654	—	16,654
Power option agreement	—	—	12	—	12
Foreign currency exchange derivatives	—	51	—	—	51
Interest rate swap derivatives	—	72,355	—	(36,505)	35,850
Total	\$—	\$128,419	\$20,355	\$ (90,017)	\$58,757

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	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2016					
Assets:					
Energy commodity derivatives	\$—	\$47,994	\$—	\$ (46,099)	\$1,895
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	69	(69)	—
Power exchange agreement	—	—	25	(25)	—
Foreign currency exchange derivatives	—	5	—	(5)	—
Interest rate swap derivatives	—	13,098	—	(4,348)	8,750
Deferred compensation assets:					
Fixed income securities (2)	1,789	—	—	—	1,789
Equity securities (2)	5,481	—	—	—	5,481
Total	\$7,270	\$61,097	\$94	\$ (50,546)	\$17,915
Liabilities:					
Energy commodity derivatives	\$—	\$56,871	\$—	\$ (55,957)	\$914
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	5,954	(69)	5,885
Power exchange agreement	—	—	13,474	(25)	13,449
Power option agreement	—	—	76	—	76
Foreign currency exchange derivatives	—	28	—	(5)	23
Interest rate swap derivatives	—	73,978	—	(39,248)	34,730
Total	\$—	\$130,877	\$19,504	\$ (95,304)	\$55,077

The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a (1) 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 trading securities and 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 3 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.

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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 \$0.2 million as of September 30, 2017 and \$0.4 million as of December 31, 2016.

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. Because the nuclear power plant O&M charges are only known for one year, all forward years are estimated assuming an annual escalation. In addition to the forward price being estimated using unobservable inputs, the Company also 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. Generally, a change in the current year O&M charges for the surrogate plants is accompanied by a directionally similar change in O&M charges in future years. There is generally not a correlation between external market prices and the O&M charges used to develop the internal forward price.

For the power commodity option agreement, the Company uses the Black-Scholes-Merton valuation model to estimate the fair value, and this model includes significant inputs not observable or corroborated in the market. These inputs include: 1) the strike price (which is an internally derived price based on a combination of generation plant heat rate factors, natural gas market pricing, delivery and other O&M charges) and 2) estimated delivery volumes. Significant increases or decreases in these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, changes in overall commodity market prices are accompanied by directionally similar changes in the strike price assumptions used in the calculation.

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, 2017 (dollars in thousands):

	Fair Value (Net) at September 30, 2017	Valuation Technique	Unobservable Input	Range
Power exchange agreement	\$ (16,654)	Surrogate facility pricing	O&M charges Escalation factor Transaction volumes	\$38.87-\$45.20/MWh (1) 5% - 2018 to 2019 396,984 - 432,357 MWWhs
Power option agreement	\$ (12)	Black-Scholes-Merton	Strike price Delivery volumes	\$34.85/MWh - 2019 \$47.54/MWh - 2018 157,517 - 222,683 MWWhs

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Natural gas exchange agreement	\$ (3,599)	Internally derived weighted average cost of gas	Forward purchase prices	\$1.70 - \$2.24/mmBTU
			Forward sales prices	\$1.63 - \$3.20/mmBTU
			Purchase volumes	115,000 - 310,000 mmBTUs
			Sales volumes	60,000 - 310,000 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2017 are \$41.95 per MWh. For ratemaking purposes the average O&M charges to be included for recovery in retail rates vary slightly between regulatory jurisdictions. The average O&M charges for the delivery year beginning in 2017 are \$45.32 for Washington and \$41.95 for Idaho.

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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	Power Option Agreement	Total
Three months ended September 30, 2017:				
Balance as of July 1, 2017	\$ (4,173)	\$ (13,784)	\$ (43)	\$ (18,000)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	617	(2,870)	31	(2,222)
Settlements	(43)	—	—	(43)
Ending balance as of September 30, 2017 (2)	\$ (3,599)	\$ (16,654)	\$ (12)	\$ (20,265)
Three months ended September 30, 2016:				
Balance as of July 1, 2016	\$ (6,857)	\$ (14,614)	\$ (105)	\$ (21,576)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	336	(1,696)	(692)	(2,052)
Settlements	—	—	—	—
Ending balance as of September 30, 2016 (2)	\$ (6,521)	\$ (16,310)	\$ (797)	\$ (23,628)
Nine months ended September 30, 2017:				
Balance as of January 1, 2017	\$ (5,885)	\$ (13,449)	\$ (76)	\$ (19,410)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	2,434	(8,035)	64	(5,537)
Settlements	(148)	4,830	—	4,682
Ending balance as of September 30, 2017 (2)	\$ (3,599)	\$ (16,654)	\$ (12)	\$ (20,265)
Nine months ended September 30, 2016:				
Balance as of January 1, 2016	\$ (5,039)	\$ (21,961)	\$ (124)	\$ (27,124)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	(2,960)	272	(673)	(3,361)
Settlements	1,478	5,379	—	6,857
Ending balance as of September 30, 2016 (2)	\$ (6,521)	\$ (16,310)	\$ (797)	\$ (23,628)

(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 9. COMMON STOCK

The Company has entered into four separate sales agency agreements under which Avista Corp.'s sales agents may offer and sell up to 3.8 million new shares of Avista Corp.'s common stock, no par value, from time to time. The sales agency agreements expire on February 29, 2020. As of September 30, 2017, 1.6 million shares have been issued under these agreements, leaving 2.2 million shares remaining to be issued. No shares were issued under these agreements in the nine months ended September 30, 2017.

In the nine months ended September 30, 2017, Avista Corp. issued 0.2 million shares of common stock, most of which were under employee incentive plans. The Company also issued a small number of shares under the 401(k) employee investment plan. Total net proceeds for all issuances were \$1.5 million.

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NOTE 10. 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, 2017		Nine months ended September 30, 2016	
Numerator:				
Net income attributable to Avista Corp. shareholders	\$4,451	\$12,234	\$88,338	\$97,137
Denominator:				
Weighted-average number of common shares outstanding-basic	64,412	63,857	64,392	63,282
Effect of dilutive securities:				
Performance and restricted stock awards	480	468	246	405
Weighted-average number of common shares outstanding-diluted	64,892	64,325	64,638	63,687
Earnings per common share attributable to Avista Corp. shareholders:				
Basic	\$0.07	\$0.19	\$1.37	\$1.53
Diluted	\$0.07	\$0.19	\$1.37	\$1.53

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

NOTE 11. 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 the California Parties (as defined in the 2016 Form 10-K). The penalty arises as a result of the Federal Energy and Regulatory Commission's (FERC) 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 2014 settlement with the California Parties insulates it from any such liability and that as a dismissed party it cannot be drawn back into the litigation. Avista Energy intends to vigorously dispute APX's assertions of indirect liability, but cannot at this time predict the eventual outcome.

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 is reducing TDG by constructing spill crest modifications on spill gates at the dam, and the Company expects to continue spill crest modifications over the next several years, in ongoing consultation with key stakeholders. Avista Corp. cannot at this time predict the outcome or estimate a range of costs associated with this contingency; however, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

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Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the United States Fish and Wildlife Service (USFWS) listed bull trout as threatened under the Endangered Species Act. In 2010, the USFWS issued a revised designation of critical habitat for bull trout, which includes the lower Clark Fork River. The USFWS issued a final recovery plan in October 2015.

The CFSA describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company evaluated the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. Parties to the CFSA have agreed to finalize the design of a fishway and plan its construction. Final design and construction costs are expected in late 2017 or early 2018. The Company believes its ongoing efforts through the CFSA continue to effectively address issues related to bull trout. Avista Corp. cannot at this time predict the outcome or estimate a range of costs associated with this contingency; however, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to fish passage at Cabinet Gorge and Noxon Rapids.

Legal Proceedings Related to the Pending Acquisition by Hydro One

See Note 13 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, three lawsuits have been filed in the United States District Court for the Eastern District of Washington, captioned as follows:

Jen 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)

In addition one lawsuit 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).

These lawsuits were filed against Avista Corporation, Hydro One Limited, Olympus Holding Corp. and Olympus Corp., 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, except that in Fink, Avista Corporation is not named and Bank of America Merrill Lynch is named as a defendant, and in the Jen and Samuelson cases Hydro One Limited, Olympus Holding Corp., and Olympus Corp. are not named as defendants.

The complaints generally allege, among other things, 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 in Fink and Sharpenter were brought only against Hydro One Limited, Olympus Holding Corp. and Olympus Corp. The complaints also allege misstatements and omissions of material facts in the Company's proxy soliciting materials relating to the special meeting of shareholders to be held November 21, 2017 to approve the acquisition. The complaints seek various remedies, including an injunction against the acquisition and monetary damages, including attorneys' fees and expenses.

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.

Interest Rate Swaps included in the 2017 Washington General Rate Cases

On October 27, 2017, UTC Staff and other parties to Avista Corp.'s electric and natural gas general rate cases filed their testimony. These parties recommended lower revenue requirements than what was proposed in Avista Corp.'s original filings. Additionally, the UTC Staff recommended the disallowance of the Washington portion of the Company's 2016 settled interest rate swaps. The total amount of the 2016 settled interest rate swaps was \$54.0 million,

with approximately 60 percent of this total being allocated to Washington.

In addition to the settled interest rate swaps from 2016, the Company has a net regulatory asset of \$8.8 million for interest rate swaps settled during the third quarter of 2017, and a net regulatory asset of \$64.4 million for unsettled interest rate swaps as of September 30, 2017 related to forecasted debt issuances. Of those amounts, approximately 60 percent relate to Washington. If recovery of the 2016 settled interest rate swap payments referenced above is disallowed by the UTC, this could change the Company's current conclusion that settlement payments related to the 2017 settled interest rate swaps and the unsettled interest

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rate swaps are probable of recovery through rates. If the Company concluded that recovery of these swap related payments were no longer probable, the Company would be required to derecognize the related regulatory assets and liabilities with an adjustment through the income statement, and any subsequent gains and losses would be recognized through the income statement rather than recorded as a regulatory asset or liability.

Interest rate swaps are a tool used throughout multiple industries to manage interest rate risk. They also provide certainty for future cash flows associated with future borrowings. Interest rate swap settlements have been included as a component of Avista Corp.'s cost of debt that has been approved by the UTC in past general rate cases. Accordingly, the Company still believes the interest rate swap payments are recoverable and will continue to work through the rate case process; however, the Company cannot predict the outcome of these rate cases and whether a disallowance will occur.

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 2016 Form 10-K for additional discussion regarding other contingencies.

NOTE 12. 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, 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)	81,045	3,469	84,514	6,598	—	91,112
Depreciation and amortization	41,516	1,452	42,968	137	—	43,105
Income (loss) from operations	31,023	1,298	32,321	(1,279)	—	31,042
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

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	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the three months ended September 30, 2016:						
Operating revenues	\$287,193	\$9,796	\$296,989	\$6,360	\$ —	\$303,349
Resource costs	115,228	3,509	118,737	—	—	118,737
Other operating expenses	72,318	2,842	75,160	6,756	—	81,916
Depreciation and amortization	38,909	1,331	40,240	193	—	40,433
Income (loss) from operations	38,554	1,629	40,183	(589)	—	39,594
Interest expense (3)	20,772	894	21,666	149	(19)	21,796
Income taxes	7,983	339	8,322	(716)	—	7,606
Net income (loss) attributable to Avista Corp. shareholders	12,673	866	13,539	(1,305)	—	12,234
Capital expenditures (4)	101,558	3,699	105,257	105	—	105,362
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)	231,727	9,236	240,963	19,863	—	260,826
Depreciation and amortization	123,249	4,347	127,596	482	—	128,078
Income (loss) from operations	193,629	12,080	205,709	(3,184)	—	202,525
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
For the nine months ended September 30, 2016:						
Operating revenues	\$989,981	\$32,689	\$1,022,670	\$17,690	\$ —	\$1,040,360
Resource costs	380,913	9,358	390,271	—	—	390,271
Other operating expenses	221,364	8,241	229,605	18,862	—	248,467
Depreciation and amortization	115,126	3,984	119,110	573	—	119,683
Income (loss) from operations	199,661	9,354	209,015	(1,745)	—	207,270
Interest expense (3)	61,652	2,684	64,336	459	(116)	64,679
Income taxes	53,004	2,910	55,914	(1,253)	—	54,661
Net income (loss) attributable to Avista Corp. shareholders	94,431	4,885	99,316	(2,179)	—	97,137
Capital expenditures (4)	274,041	14,031	288,072	270	—	288,342
Total Assets:						
As of September 30, 2017:	\$5,116,059	\$276,426	\$5,392,485	\$59,747	\$ —	\$5,452,232
As of December 31, 2016:	\$4,975,555	\$273,770	\$5,249,325	\$60,430	\$ —	\$5,309,755

(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, 2017 include acquisition costs of \$6.7 million and \$8.0 million, respectively, which are separately disclosed on the Condensed

Consolidated Statements of Income.

(3) Including interest expense to affiliated trusts.

(4) The capital expenditures for the other businesses are included in other investing activities on the Condensed Consolidated Statements of Cash Flows.

NOTE 13. 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. (the

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"Merger"), 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 Merger, each share of Avista Corp. Common Stock issued and outstanding, other than Dissenting Shareholder Shares (as defined in the Merger Agreement) and shares of Avista Corp. Common Stock that are owned by Hydro One, US Parent or Merger Sub or any of their respective subsidiaries, will be converted automatically into the right to receive an amount in cash equal to \$53.00, without interest.

Consummation of the Merger 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 Merger 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 Merger, including approval from the FERC, the Committee on Foreign Investment in the United States (CFIUS), the Federal Communications Commission (FCC), the UTC, IPUC, Public Service Commission of the State of Montana (MPSC), OPUC, and the RCA, and (iii) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

On September 14, 2017, Avista Corp. and Hydro One filed applications for approval of the acquisition with the FERC, the UTC, the IPUC, the OPUC, the MPSC and the RCA, requesting approval of the transaction on or before August 14, 2018. However, the OPUC has set a procedural schedule with an end date no later than September 14, 2018.

As part of the applications for approval, Hydro One and Avista Corp. have proposed to flow through to Avista Corp.'s Washington, Idaho and Oregon retail customers, a rate credit totaling \$31.5 million among the three jurisdictions over a 10-year period beginning at the time the Merger closes. In addition, to the extent Avista Corp. and Hydro One in a future rate proceeding demonstrate that cost savings, or benefits, directly related to the proposed transaction are already being flowed through to customers through base retail rates, the rate credit to customers would be reduced by an amount up to the \$22.0 million over the 10-year period. The portion of the total rate credit that is not allowable for offset effectively represents acceptance by Hydro One of a lower rate of return during the 10-year period.

On October 2, 2017, the Company distributed the definitive proxy statement associated with a special meeting of shareholders to be held on November 21, 2017 to vote on the transaction. The transaction is expected to close in the second half of 2018 subject to all of the above referenced approvals and the satisfaction or waiver of other specified conditions.

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 Merger 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 Merger 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.

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 Merger 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 Merger and the absence of a Burdensome Condition (as defined in the Merger Agreement) in any required regulatory approval, have been satisfied). 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 a termination fee of \$103.0 million (Company Termination Fee). 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 of obtaining regulatory approvals, Hydro One will be required to pay Avista Corp. a termination fee of \$103.0 million.

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See Note 11 for discussion of shareholder lawsuits filed against the Company, the Company's directors, Hydro One Limited, Olympus Holding Corp., and Olympus Corp. in relation to the Merger Agreement and the proposed Merger. See also the Company's Current Report on Form 8-K, filed with the SEC on July 19, 2017, and its definitive proxy statement relating to the special meeting of shareholders to approve the proposed transaction, filed with the SEC on October 2, 2017. The Merger Agreement was filed as Exhibit 2.1 to such Current Report.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have reviewed the accompanying condensed consolidated balance sheet of Avista Corporation and subsidiaries (the "Company") as of September 30, 2017, and the related condensed consolidated statements of income and comprehensive income for the three-month and nine-month periods ended September 30, 2017 and 2016 and the related condensed consolidated statements of equity and cash flows for the nine-month periods ended September 30, 2017 and 2016. These interim financial statements are the responsibility of the Company's management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 Public Company Accounting Oversight Board (United States), 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.

Based on our reviews, we are not aware of any material modifications that should be made to such condensed consolidated interim financial statements for them 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), the consolidated balance sheet of Avista Corporation and subsidiaries as of December 31, 2016, and the related consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for the year then ended (not presented herein); and in our report dated February 21, 2017, 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, 2016 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP
Seattle, Washington
October 31, 2017

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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 2016 Form 10-K.

Business Segments

Our business segments have not changed during the nine months ended September 30, 2017. See the 2016 Form 10-K as well as "Note 12 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,	
	2017	2016	2017	2016
Avista Utilities	\$5,419	\$12,673	\$85,623	\$94,431
AEL&P	427	866	5,961	4,885
Other	(1,395)	(1,305)	(3,246)	(2,179)
Net income attributable to Avista Corp. shareholders	\$4,451	\$12,234	\$88,338	\$97,137

Executive Level Summary

Overall Results

Net income attributable to Avista Corp. shareholders was \$4.5 million for the three months ended September 30, 2017, a decrease from \$12.2 million for the three months ended September 30, 2016. Net income attributable to Avista Corp. shareholders was \$88.3 million for the nine months ended September 30, 2017, a decrease from \$97.1 million for the nine months ended September 30, 2016.

The decrease in earnings for both the third quarter and first nine months of 2017 was due to a decrease in earnings at Avista Utilities and an increase in losses at our other businesses (primarily during the first half of the year). There was also a decrease in earnings at AEL&P for the third quarter, but an increase in earnings for the first nine months of 2017.

Avista Utilities' earnings decreased for both the third quarter and year-to-date 2017 due to an increase in other operating expenses, primarily due to an increase in generation and distribution maintenance costs, compensation costs, depreciation and amortization and interest expense. As discussed below, our 2016 requests for general rate increases in Washington were denied, as was our 2017 Washington power cost rate adjustment; therefore, we are not receiving regulatory recovery of the increase in expenses. In addition, there were also acquisition costs incurred during the second and third quarters of 2017, which are not being passed through to customers. Further, since a majority of these acquisition costs are not deductible for income tax purposes, earnings reflect the full amount of such costs. The increase in costs was partially offset by an increase in gross margin (operating revenues less resource costs) as a result of general rate increases in Idaho and Oregon, customer growth and lower electric resource costs. See "Results of Operations – Overall – Non-GAAP Financial Measures" for further discussion of gross margin.

AEL&P earnings decreased for the third quarter 2017, but increased for the year-to-date 2017. For both the third quarter and year-to-date, there was an increase in revenue due to an interim general rate increase, higher electric loads and a slight increase in residential and commercial customers. During the third quarter 2017, there was a customer refund charge related to a settlement agreement in AEL&P's electric general rate case which mostly offset the revenue increase for the third quarter. There was also an increase in operating expenses for both the third quarter and

year-to-date and a decrease in AFUDC and capitalized interest due to the construction of an additional back-up generation plant completed in 2016.

The increase in losses at our other businesses for the year-to-date 2017 was primarily related to renovation expenses and increased compliance costs at one of our subsidiaries.

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

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regulatory agencies and Avista Corp. shareholders, the transaction is expected to close during the second half of 2018. At the effective time of the Merger, each share of Avista Corp. Common Stock issued and outstanding other than Dissenting Shareholder Shares (as defined in the Merger Agreement) and shares of Avista Corp. Common Stock that are owned by Hydro One, US Parent or Merger Sub or any of their respective subsidiaries, will be converted automatically into the right to receive an amount in cash equal to \$53.00, without interest. For further information, see “Notes 11 and 13 of the Notes to Condensed Consolidated Financial Statements.”

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 (Order 05) that concluded our electric and natural gas general rate cases that were originally filed with the UTC in February 2015. New electric and natural gas rates were effective on January 11, 2016.

The UTC-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 UTC also approved a rate of return (ROR) on rate base of 7.29 percent, with a common equity ratio of 48.5 percent and a 9.5 percent return on equity (ROE).

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

On January 19, 2016, the Industrial Customers of Northwest Utilities (ICNU) and the Public Counsel Unit of the Washington State Office of the Attorney General (PC) filed a Joint Motion for Clarification with the UTC. In the Motion for Clarification, ICNU and PC requested that the UTC clarify the calculation of the electric attrition adjustment and the end-result revenue decrease of \$8.1 million. ICNU and PC provided their own calculations in their Motion, and suggested that the revenue decrease should have been \$19.8 million based on their reading of the UTC’s Order.

On January 19, 2016, the UTC Staff, which is a separate party in the general rate case proceedings from the UTC Advisory Staff, filed a Motion to Reconsider with the UTC. In its Motion to Reconsider, the Staff provided calculations and explanations that suggested that the electric revenue decrease should have been a revenue decrease of \$27.4 million instead of \$8.1 million, based on its reading of the UTC’s Order. Further, on February 4, 2016, the UTC Staff filed a Motion to Reopen Record for the Limited Purpose of Receiving into Evidence Instruction on Use and Application of Staff’s Attrition Model, and sought to supplement the record “to incorporate all aspects of the Company’s Power Cost Update.” Within this Motion, UTC Staff updated its suggested electric revenue decrease to \$19.6 million. None of the parties in their Motions raised issues with the UTC’s decision on the natural gas revenue increase of \$10.8 million.

On February 19, 2016, the UTC 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

On March 18, 2016, PC filed in Thurston County Superior Court a Petition for Judicial Review of the UTC's Order 05 and Order 06 described above that concluded our 2015 electric and natural gas general rate cases. In its Petition for Judicial Review, PC seeks judicial review of five aspects of Order 05 and Order 06, alleging, among other things, that

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(1) the UTC exceeded its statutory authority by setting rates for our natural gas and electric services based on amounts for utility plant and facilities that are not "used and useful" in providing utility service to customers; (2) the UTC acted arbitrarily and capriciously in granting an attrition adjustment for our electric operations after finding that we did not meet the newly articulated standard regarding attrition adjustments; (3) the UTC erred in applying the "end results test" to set rates for our electric operations that are not supported by the record; (4) the UTC did not correct its calculation of our electric rates after significant errors were brought to its attention; and (5) the UTC's calculation of our electric rates lacks substantial evidence.

PC is requesting that the Court (1) vacate or set aside portions of the UTC's orders; (2) identify the errors contained in the UTC's orders; (3) find that the rates approved in Order 05 and reaffirmed in Order 06 are unlawful and not fair, just and reasonable; (4) remand the matter to the UTC for further proceedings consistent with these rulings, including a determination of our revenue requirement for electric and natural gas services; and (5) find the customers are entitled to a refund.

On April 18, 2016, PC filed an application with the Thurston County Superior Court to certify this matter for review directly by the Court of Appeals, an intermediate appellate court in the State of Washington. The matter was certified on April 29, 2016 and accepted by the Court of Appeals on July 29, 2016. The parties provide briefs to the Court, after which the Court will set the matter for argument. On July 7, 2017, ICNU filed a brief in support of PC and the UTC and Avista Corp. responded. Oral argument was held on October 24, 2017 before the court. A decision from the Court is not expected until late 2017, at the earliest.

In its brief to the Court, the UTC, while defending the use of its attrition adjustment nevertheless requested a partial remand back to the UTC to reevaluate the implementation of our power cost update as part of the general rate case on appeal, doing so by means of a supplemental evidentiary hearing. The power cost update at issue represents approximately \$12.0 million of costs.

The new rates established by Order 05 will continue in effect while the Petition for Judicial Review is being considered. We believe the UTC's Order 05 and Order 06 finalizing the electric and natural gas general rate cases provide a reasonable end result for all parties. If the outcome of the judicial review were to result in an electric rate reduction greater than the decrease ordered by the UTC, it may result in a refund liability to customers of up to \$9.5 million, which is net of an approximately \$2.5 million refund for Washington electric customers related to the 2016 provision for earnings sharing that we have already accrued.

2016 General Rate Cases

On December 15, 2016, the UTC issued an order related to our Washington electric and natural gas general rate cases that were originally filed with the UTC in February 2016. The UTC order denied the Company's proposed electric and natural gas rate increase requests of \$38.6 million and \$4.4 million, respectively. Accordingly, our current electric and natural gas retail rates remained unchanged in Washington State, following the order.

Our original requests were based on a proposed ROR of 7.64 percent with a common equity ratio of 48.5 percent and a 9.9 percent ROE.

We determined that an appeal of the UTC's decision to the courts would involve a significant amount of uncertainty regarding the level of success of such an appeal, as well as the timing of any value that might come following a process that would take between one and two years. The Company believes greater long-term value can be achieved through focusing on new general rate cases than through appealing the UTC's decision in the courts.

2017 General Rate Cases

On May 26, 2017, we filed two requests with the UTC to recover costs related to power supply and operating costs as well as capital investments made since the last determination of our rate base in the 2015 Washington general rate cases.

The two filings are summarized as follows:

Power Cost Rate Adjustment

The first filing was an electric only power cost rate adjustment (PCRA) that was designed to update and reset power supply costs, effective September 1, 2017. We requested an overall increase in billed electric rates of 2.9 percent (designed to increase annual electric revenues by \$15.0 million). On August 10, 2017, the PCRA filing was dismissed by the UTC.

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Our power supply costs, on a normalized basis, are much higher than those built into current base retail rates. The increased level of costs are included in our pending general rate case in Washington, which is scheduled to be concluded by April 26, 2018. The dismissal of the PCRA by the UTC does not impact our general rate requests discussed below.

General Rate Requests

The second request relates to electric and natural gas general rate cases. We filed three-year rate plans for electric and natural gas and have requested the following for each year (dollars in millions):

Effective Date	Electric			Natural Gas		
	Proposed Revenue Increase	Proposed Base Rate Increase	%	Proposed Revenue Increase	Proposed Base Rate Increase	%
May 1, 2018	\$61.4	12.5	%	\$8.3	9.3	%
May 1, 2019 (1)	\$14.0	2.5	%	\$4.2	4.4	%
May 1, 2020 (1)	\$14.4	2.5	%	\$4.4	4.4	%

As a part of the electric rate plan, we have proposed to update power supply costs through a Power Supply Update, (1) the effects of which would also go into effect on May 1, 2019 and May 1, 2020. The requested revenue increases for 2019 and 2020 do not include any power supply adjustments.

Our request is based on a proposed ROR of 7.76 percent with a common equity ratio of 50.0 percent and a 9.9 percent ROE.

As a part of the three-year rate plan, if approved, we would not file another general rate case until June 1, 2020, with new rates effective no earlier than May 1, 2021.

The major drivers of these general rate case requests is to recover the costs associated with our capital investments to replace infrastructure that has reached the end of its useful life, as well as respond to the need for reliability and technology investments required to maintain our integrated energy services grid. Among the capital investments included in the filings are:

- Major hydroelectric investments at the Little Falls and Nine Mile hydroelectric plants.
- Generator maintenance at the Kettle Falls biomass plant that will ensure efficient generation and operations.
- The ongoing project to systematically replace portions of natural gas distribution pipe in our service area that were installed prior to 1987, as well as replacement of other natural gas service equipment.
- Transmission and distribution system and asset maintenance, such as wood pole replacements, feeder upgrades, and substation and transmission line rebuilds to maintain reliability for our customers.
- Technology upgrades that support necessary business processes and operational efficiencies that allow us to effectively manage the utility and serve customers.
- A refresh of the customer-facing website, providing relevant information, greater accessibility on mobile devices, easier navigation, and a streamlined payment experience.

The UTC has up to 11 months to review the general rate case filings and issue a decision, which is scheduled to be concluded by April 26, 2018.

On October 27, 2017, UTC Staff and other parties to our electric and natural gas general rate cases filed their testimony. These parties recommended lower revenue requirements than what was proposed in our original filings. Additionally, the UTC Staff recommended the disallowance of the Washington portion of our 2016 settled interest rate swaps. The total amount of the 2016 settled interest rate swaps was \$54.0 million, with approximately 60 percent of this total being allocated to Washington.

In addition to the settled interest rate swaps from 2016, we have a net regulatory asset of \$8.8 million for interest rate swaps settled during the third quarter of 2017, and a net regulatory asset of \$64.4 million for unsettled interest rate

swaps as of September 30, 2017 related to forecasted debt issuances. Of those amounts, approximately 60 percent relate to Washington. If recovery of the 2016 settled interest rate swap payments referenced above is disallowed by the UTC, this could change our current conclusion that settlement payments related to the 2017 settled interest rate swaps and the unsettled interest rate swaps are probable of recovery through rates. If we concluded that recovery of these swap related payments were no longer probable, we would be required to derecognize the related regulatory assets and liabilities

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with an adjustment through the income statement, and any subsequent gains and losses would be recognized through the income statement rather than recorded as a regulatory asset or liability.

Interest rate swaps are a tool used throughout multiple industries to manage interest rate risk. They also provide certainty for future cash flows associated with future borrowings. Interest rate swap settlements have been included as a component of our cost of debt that has been approved by the UTC in past general rate cases. Accordingly, we still believe the interest rate swap payments are recoverable and will continue to work through the rate case process; however, we cannot predict the outcome of these rate cases and whether a disallowance will occur.

Idaho General Rate Cases

2016 General Rate Case

In December 2016, the IPUC approved a settlement agreement between us and other parties in our electric general rate case, concluding our Idaho electric general rate case originally filed in May 2016. New rates took effect on January 1, 2017 under the settlement agreement. We did not file a natural gas general rate case in 2016.

The settlement agreement increased annual electric base rates by 2.6 percent (designed to increase annual electric revenues by \$6.3 million). The settlement revenue increase is based on a ROR of 7.58 percent with a common equity ratio of 50 percent and a 9.5 percent ROE.

In addition to the agreed upon increase in electric revenues to recover costs primarily driven by our increased capital investments in infrastructure to serve customers, the settlement agreement includes the continued recovery of approximately \$4.1 million in costs related to the Palouse Wind Project through the Power Cost Adjustment (PCA) mechanism rather than through base rates.

2017 General Rate Cases

On October 20, 2017, we reached a settlement agreement with multiple parties to our electric and natural gas general rate cases that has been submitted to the IPUC for its consideration. If approved, new rates would take effect January 1, 2018 and January 1, 2019.

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

Effective Date	Electric			Natural Gas		
	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	1.9	%	\$1.1	2.7	%

The settlement agreement is based on a ROR of 7.61 percent with a common equity ratio of 50.0 percent and a 9.5 percent ROE.

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

The Company's original request was a two-year rate plan and requested the following electric and natural gas base rate changes each year (dollars in millions):

Effective Date	Electric			Natural Gas		
	Proposed Revenue Increase	Proposed Base Rate Increase	%	Proposed Revenue Increase	Proposed Base Rate Increase	%
January 1, 2018	\$18.6	7.5	%	\$3.5	8.8	%
January 1, 2019	\$9.9	3.7	%	\$2.1	5.0	%

The original requests were based on a proposed ROR of 7.81 percent with a common equity ratio of 50.0 percent and a 9.9 percent ROE.

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Oregon General Rate Cases

2015 General Rate Case

On February 29, 2016, the OPUC issued a preliminary order (and a final order on March 15, 2016) concluding our natural gas general rate case, which was originally filed with the OPUC in May 2015. The OPUC order approved rates designed to increase overall billed natural gas rates by 4.9 percent (designed to increase annual natural gas revenues by \$4.5 million). New rates went into effect on March 1, 2016. The final OPUC order incorporated two partial settlement agreements which were entered into during November 2015 and January 2016.

The OPUC order provides for an overall authorized ROR of 7.46 percent with a common equity ratio of 50 percent and a 9.4 percent ROE.

The November 2015 partial settlement agreement, approved by the OPUC, included a provision for the implementation of a decoupling mechanism, similar to the Washington and Idaho mechanisms described below. See further description and a summary of the balances recorded under this mechanism below.

2016 General Rate Case

On September 13, 2017, the OPUC approved an all-party settlement agreement that was filed with the OPUC in May 2017, 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 will be effective 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 approximately \$0.8 million in the second quarter of 2017.

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

AMI Project

In March 2016, the UTC granted our Petition for an Accounting Order to defer and include in a regulatory asset the undepreciated value of our existing Washington electric meters for the opportunity for later recovery. This accounting treatment is related to our plans to replace approximately 253,000 of our existing electric meters with new two-way digital meters and the related software and support services through our AMI project in Washington State.

Replacement of the meters is expected to begin in the second half of 2018. As of September 30, 2017, the estimated undepreciated value for the existing meters is \$20.1 million.

In May 2017, we filed a Petition with the UTC requesting deferred accounting treatment for the investment costs associated with the Washington AMI project, including components such as meter communication networks, information management systems and natural gas ERTs. The Petition requested the deferral and inclusion in a regulatory asset of all AMI investment costs over the multi-year implementation period, until the costs could be reviewed for prudence in a future regulatory proceeding and recovered in retail rates. Through discussions with UTC staff, we developed an alternative proposal to our original Petition and on September 14, 2017, the UTC approved our alternative proposal to defer the depreciation expense associated with AMI, along with a carrying charge, and to seek recovery of the deferral and carrying charge in a future general rate case. Cost savings, such as reduced meter reading costs, will occur during the implementation period which will offset a portion of the AMI costs not being deferred.

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

Alaska Electric Light and Power Company

Alaska General Rate Case

In October 2017, AEL&P filed an all-party settlement agreement with the RCA related to its electric general rate case, which was originally filed in September 2016. If approved by the RCA, the settlement agreement is designed to increase base electric revenue by 3.86 percent or \$1.3 million.

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In September 2016, when AEL&P filed its original electric general rate case, it was granted a refundable interim base rate increase of 3.86 percent (designed to increase electric revenues by \$1.3 million), which took effect in November 2016. If the settlement agreement is approved by the RCA, these rates will become permanent.

In addition, in the settlement agreement, AEL&P agreed to retain \$0.9 million less revenue from the Greens Creek Mine than what was included in the original general rate case request. As such, during the third quarter of 2017, AEL&P recorded a refund liability to customers of \$0.8 million, which will be refunded to customers during 2018. The amount of revenue from Greens Creek Mine that is retained by AEL&P is used to offset revenue requirements that would otherwise be required from retail customers.

The settlement agreement reflects an 8.91 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 gross margin or net income. In Oregon, we absorb (cost or benefit) 10 percent of the difference between actual and projected 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 \$34.4 million as of September 30, 2017 and a liability of \$30.8 million as of December 31, 2016. These balances represent amounts due to customers.

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used to track certain differences between Avista Utilities' actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for our Washington customers and defer these differences (over the \$4.0 million deadband and sharing bands) for future surcharge or rebate to customers. See the 2016 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 was a liability of \$21.9 million as of September 30, 2017, compared to a liability of \$21.3 million as of December 31, 2016. 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 for future surcharge or rebate to 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 \$5.9 million as of September 30, 2017 and a liability of \$2.2 million as of December 31, 2016. These deferred power cost balances represent amounts due to customers.

Decoupling and Earnings Sharing Mechanisms

Decoupling is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of Avista Utilities' jurisdictions, each month 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 revenues based on actual usage is deferred and either surcharged or rebated to customers beginning in the following year. Only the residential and commercial customer classes are included in our decoupling mechanisms described below.

Washington Decoupling and Earnings Sharing Mechanisms

In Washington, the UTC approved our decoupling mechanisms for electric and natural gas for a five-year period beginning January 1, 2015. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to a 3 percent increase on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

The decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations are made for the calendar year just ended. These earnings tests reflect actual decoupled revenues, normalized power supply costs and other normalizing adjustments. The operation of the Washington decoupling and earnings sharing mechanisms has not changed for the nine months ended September 30, 2017. These decoupling and earnings sharing mechanisms are more fully described in the 2016 Form 10-K. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

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Idaho Fixed Cost Adjustment (FCA) and Earnings Sharing Mechanisms

In Idaho, the IPUC approved the implementation of FCAs for electric and natural gas (similar in operation and effect to the Washington decoupling mechanisms) for an initial term of three years, beginning January 1, 2016.

For the period 2013 through 2015, we had an after-the-fact earnings test such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earned more than a 9.8 percent ROE, we were required to share with customers 50 percent of any earnings above the 9.8 percent. This after-the-fact earnings test was discontinued, effective January 1, 2016, as part of the settlement of our 2015 Idaho electric and natural gas general rates cases. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Oregon Decoupling Mechanism

In February 2016, the OPUC approved the implementation of a decoupling mechanism for natural gas, similar to the Washington and Idaho mechanisms described above. The decoupling mechanism became effective on March 1, 2016. There will be an opportunity for interested parties to review the mechanism and recommend changes, if any, by September 2019. An earnings review is conducted on an annual basis, which is filed by us with the OPUC on or before June 1 of each year for the prior calendar year. In the annual earnings review, if we earn more than 100 basis points above our allowed return on equity, one-third of the earnings above the 100 basis points would be deferred and later returned to customers. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Cumulative Decoupling and Earnings Sharing Mechanism Balances

As of September 30, 2017 and December 31, 2016, we had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in our various jurisdictions (dollars in thousands):

	September 30, 2017	December 31, 2016
Washington		
Decoupling surcharge (1)	\$ 14,783	\$ 30,408
Provision for earnings sharing rebate (1)	(800)	(5,113)
Idaho		
Decoupling surcharge	\$ 5,410	\$ 8,292
Provision for earnings sharing rebate	(3,064)	(5,184)
Oregon		
Decoupling surcharge	\$ 335	\$ 2,021

When we make our annual decoupling regulatory filing, typically during the third quarter, we apply the balance of (1) the provision for earnings sharing rebate for the relevant time period to either offset the decoupling surcharge balance, or increase the decoupling rebate balance.

See "Results of Operations - Avista Utilities" for further discussion of the amounts recorded to operating revenues in 2017 and 2016 related to the decoupling and earnings sharing mechanisms.

Results of Operations - Overall

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

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

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Three months ended September 30, 2017 compared to the three months ended September 30, 2016

The following graph shows the total change in net income attributable to Avista Corp. shareholders for the third quarter of 2016 to the third quarter of 2017, as well as the various factors that caused such change (dollars in millions):

Utility revenues decreased due to a decrease at Avista Utilities, partially offset by an increase at AEL&P. Avista Utilities' revenues decreased primarily due to a decrease in electric and natural gas wholesale sales and a decrease in electric sales of fuel. These revenue decreases were partially offset by an electric general rate increase in Idaho, a natural gas general rate increase in Oregon and higher retail electric revenues. Retail electric revenues increased as a result of higher cooling loads due to weather that was warmer than the prior year and customer growth. There were net electric decoupling rebates during both the third quarter of 2017 and 2016 and net natural gas decoupling surcharges during both the third quarter of 2017 and 2016. The electric rebates were larger in 2017 compared to 2016 due to weather that was warmer than normal in 2017. AEL&P's revenues increased primarily due to a general rate increase and higher retail heating loads due to weather that was cooler than the prior year. There was also a slight increase in the number of customers at AEL&P.

Utility resource costs decreased due to a decrease at Avista Utilities, partially offset by an increase at AEL&P. The decrease at Avista Utilities was primarily due to a decrease in purchased power, resulting from a decrease in prices, partially offset by a slight increase in volumes. The increase at AEL&P was primarily due to a customer refund liability related to AEL&P's general rate case settlement.

The increase in utility other operating expenses was due to an increase at Avista Utilities and a slight increase at AEL&P. The increase at Avista Utilities was the result of an increase in generation and distribution maintenance costs and higher compensation costs, partially offset by decreases in pension, other postretirement benefit and medical expenses.

The acquisition costs are related to the pending Hydro One acquisition and consist primarily of consulting, banking fees, legal fees and employee time and are not being passed through to customers.

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

Income taxes decreased due to a decrease in income before income taxes. Our effective tax rate was 53.6 percent for the third quarter of 2017 compared to 38.3 percent for the third quarter of 2016. The effective tax rate increased during 2017 because the majority of acquisition costs, which reduce income before income taxes, are not deductible for tax purposes and thus do not reduce income tax expense.

Other was primarily related to an increase in interest expense, due to additional debt being outstanding during 2017 as compared to 2016 and partially due to an increase in the overall interest rate. Also, there was an increase in utility taxes other than income taxes primarily due to revenue-related taxes, which resulted from an increase in retail electric revenue.

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Nine months ended September 30, 2017 compared to the nine months ended September 30, 2016

The following graph shows the total change in net income attributable to Avista Corp. shareholders for the nine months ended September 30, 2016 to the nine months ended September 30, 2017, as well as the various factors that caused such change (dollars in millions):

Utility revenues increased due to increases at both Avista Utilities and AEL&P. Avista Utilities' revenues increased primarily due to an electric general rate increase in Idaho, a natural gas general rate increase in Oregon and higher retail electric and natural gas revenues. The higher electric and natural gas retail revenues were from increased heating loads due to customer growth and weather that was cooler than the prior year during the heating season. Also, during the third quarter, weather was warmer than the prior year, which increased electric cooling loads. The increased utility revenues were partially offset by decoupling rebates in the first nine months of 2017 due to weather that fluctuated from normal. This compares to decoupling surcharges during the first nine months of 2016. AEL&P's revenues increased primarily due to a general rate increase and higher retail heating loads due to weather that was cooler than the prior year. There was also a slight increase in the number of customers at AEL&P.

Utility resource costs decreased due to a decrease at Avista Utilities, partially offset by an increase at AEL&P. The decrease at Avista Utilities was primarily due to a decrease in purchased power, resulting from a decrease in wholesale prices, partially offset by an increase in volumes, and a decrease in fuel for generation resulting from higher hydroelectric generation and lower thermal generation. The increase at AEL&P was primarily due to a customer refund liability related to AEL&P's general rate case settlement.

The increase in utility other operating expenses was due to an increase at Avista Utilities and a slight increase at AEL&P. The increase at Avista Utilities' was the result of an increase in generation and distribution maintenance costs, higher compensation costs, as well as a write-off in Oregon of utility plant associated with a general rate case settlement. The increased costs were partially offset by decreases in pension, other postretirement benefit and medical expenses.

The acquisition costs are related to the pending Hydro One acquisition and consist primarily of consulting, banking fees, legal fees and employee time and are not being passed through to customers.

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

Income taxes decreased due to a decrease in income before income taxes. Our effective tax rate was 36.9 percent for 2017, compared to 36.0 percent for 2016. The effective tax rate increased during 2017 because the majority of acquisition costs, which reduce income before income taxes, are not deductible for tax purposes and thus do not reduce income tax expense.

Other was primarily related to an increase in interest expense, due to additional debt being outstanding during 2017 as compared to 2016 and partially due to an increase in the overall interest rate. Also, there was an increase in utility taxes other than income taxes primarily due to revenue-related taxes, which resulted from an increase in electric and natural gas retail revenue.

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Non-GAAP Financial Measures

The following discussion for Avista Utilities includes two financial measures that are considered “non-GAAP financial measures,” electric gross margin and natural gas gross margin. In the AEL&P section, we include a discussion of electric gross 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 presentation of electric gross margin and natural gas gross margin is intended to supplement an understanding of operating performance. We use these measures to determine whether the appropriate amount of revenue is being collected from our customers to allow for the recovery of energy resource costs and operating costs, as well as to analyze how changes in loads (due to weather, economic or other conditions), rates, supply costs and other factors impact our results of operations. In addition, we present electric and natural gas gross margin separately below for Avista Utilities since each business has different cost sources, cost recovery mechanisms and jurisdictions, such that separate analysis is beneficial. These measures are not intended to replace income from operations as determined in accordance with GAAP as an indicator of operating performance. The calculations of electric and natural gas gross margins are presented below.

Results of Operations - Avista Utilities

Three months ended September 30, 2017 compared to the three months ended September 30, 2016

The following table presents Avista Utilities' operating revenues, resource costs and resulting gross margin for the three months ended September 30 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2017	2016	2017	2016	2017	2016	2017	2016
Operating revenues	\$231,419	\$237,768	\$79,938	\$83,335	\$(30,581)	\$(33,910)	\$280,776	\$287,193
Resource costs	79,598	90,445	55,499	58,693	(30,581)	(33,910)	104,516	115,228
Gross margin	\$151,821	\$147,323	\$24,439	\$24,642	\$—	\$—	\$176,260	\$171,965

The gross margin on electric sales increased \$4.5 million and the gross margin on natural gas sales decreased \$0.2 million in the third quarter of 2017 compared to the third quarter of 2016. The increase in electric gross margin was primarily due to a general rate increase in Idaho, customer growth and lower resource costs. For the third quarter of 2017, we had a \$1.0 million pre-tax expense under the ERM in Washington, compared to a \$1.6 million pre-tax expense for the third quarter of 2016. For the full year of 2017, we expect to be in a benefit position under the ERM within the \$4 million deadband, primarily due to above normal hydroelectric generation for the year, which allowed us to engage in additional optimization activities.

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.

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The following graphs present Avista Utilities' utility 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 it also includes revenues and rebates from decoupling.

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The following table presents Avista Utilities' decoupling and customer earnings sharing mechanisms by jurisdiction that are reflected in utility electric operating revenues for the three months ended September 30 (dollars in thousands):

	Electric Operating Revenues	
	2017	2016
Washington		
Decoupling surcharge (rebate)	\$(4,092)	\$266
Provision for earnings sharing	—	355
Idaho		
Decoupling rebate	\$(918)	\$(515)

Total electric revenues decreased \$6.3 million for the third quarter of 2017 as compared to the third quarter of 2016 primarily reflecting the following:

- an \$11.5 million increase in retail electric revenue due to an increase in total MWhs sold (increased revenues \$8.3 million) and an increase in revenue per MWh (increased revenues \$3.2 million).

The increase in total retail MWhs sold was the result of weather that was warmer than the prior year (which increased electric cooling loads), as well as customer growth. Compared to the third quarter of 2016, residential electric use per customer increased 8 percent and commercial use per customer increased 2 percent. Cooling degree days in Spokane were 39 percent above normal and 79 percent above the third quarter of 2016.

The increase in revenue per MWh was primarily due to a general rate increase in Idaho and a greater portion of retail revenues from residential customers in the third quarter of 2017.

- a \$7.2 million decrease in wholesale electric revenues due to a decrease in sales prices (decreased revenues \$8.0 million), partially offset by an increase in sales volumes (increased revenues \$0.8 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.

- a \$5.0 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 2017, \$13.6 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 2016, \$13.8 million of these sales were made to our natural gas operations.

- a \$4.8 million decrease in electric revenue due to decoupling. Weather was significantly warmer than normal in the third quarter of 2017, which resulted in large decoupling rebates. Weather was close to normal in third quarter of 2016, which resulted in immaterial decoupling adjustments. Decoupling mechanisms are not impacted by fluctuations in weather compared to prior year, they are only impacted by weather fluctuations as compared to normal weather.

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The following graphs present our utility 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 it also includes revenues and rebates from decoupling.

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The following table presents Avista Utilities' decoupling and customer earnings sharing mechanisms by jurisdiction that are reflected in utility natural gas operating revenues for the three months ended September 30 (dollars in thousands):

	Natural Gas Operating Revenues	
	2017	2016
Washington		
Decoupling surcharge (rebate)	\$(45)	\$376
Provision for earnings sharing (rebate)	(207)	177
Idaho		
Decoupling rebate	\$(30)	\$(82)
Oregon		
Decoupling surcharge	\$350	\$486

Total natural gas revenues decreased \$3.4 million for the third quarter of 2017 as compared to the third quarter of 2016 primarily reflecting the following:

a \$1.7 million decrease in natural gas retail revenues due to lower retail rates (decreased revenues \$1.9 million), partially offset by a slight increase in volumes (increased revenues \$0.2 million).

We sold slightly more retail natural gas in the third quarter of 2017 as compared to the third quarter of 2016. 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, partially offset by a general rate increase in Oregon.

a \$1.1 million decrease in wholesale natural gas revenues due to a decrease in volumes (decreased revenues \$5.1 million), partially offset by an increase in prices (increased revenues \$4.0 million). In the third quarter of 2017, \$17.0 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 2016, \$20.1 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 \$0.5 million decrease in natural gas revenue due to decoupling. Retail natural gas loads, changes in customer usage and resulting decoupling surcharges or rebates during the third quarter are typically not significant to the full year.

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

	Electric Customers		Natural Gas Customers	
	2017	2016	2017	2016
Residential	334,274	330,435	306,706	300,168
Commercial	42,241	41,830	35,087	34,792
Interruptible	—	—	37	35
Industrial	1,336	1,340	253	256
Public street and highway lighting	577	559	—	—
Total retail customers	378,428	374,164	342,083	335,251

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The following graphs present our utility 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 \$17.0 million and \$20.1 million for the three months ended September 30, 2017 and September 30, 2016, respectively.

Total natural gas resource costs in the graph above include intracompany resource costs of \$13.6 million and \$13.8 million for the three months ended September 30, 2017 and September 30, 2016, respectively.

Total electric resource costs decreased \$10.8 million for the third quarter of 2017 as compared to the third quarter of 2016 primarily reflecting the following:

- an \$8.4 million decrease in purchased power due to a decrease in wholesale prices (decreased costs \$8.5 million), partially offset by a slight increase in the volume of power purchases (increased costs \$0.1 million).
The fluctuation in volumes and prices was primarily the result of our optimization activities during the quarter.
- a \$0.8 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

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part of the resource optimization process. When the fuel or related derivative instruments are sold, that revenue is included in sales of fuel.

a \$2.1 million decrease from amortizations and deferrals of power costs. This change was primarily the result of lower net power supply costs.

a \$0.4 million net increase from other regulatory amortizations and other electric resource costs.

Total natural gas resource costs decreased \$3.2 million for the third quarter of 2017 as compared to the third quarter of 2016 primarily reflecting the following:

a \$5.3 million decrease in natural gas purchased due to a decrease in total therms purchased (decreased costs \$4.8 million) and a decrease in the price of natural gas (decreased costs \$0.5 million). Total therms purchased decreased due to a decrease in wholesale sales.

a \$0.2 million decrease in other regulatory amortizations.

a \$2.1 million increase from amortizations and deferrals of natural gas costs. This reflects lower natural gas prices compared to our authorized PGA rates and the deferral of these lower costs, which occurred in the current quarter for future rebate to customers.

Nine months ended September 30, 2017 compared to the nine months ended September 30, 2016

The following table presents our operating revenues, resource costs and resulting gross margin for the nine months ended September 30 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2017	2016	2017	2016	2017	2016	2017	2016
Operating revenues	\$725,695	\$735,361	\$330,580	\$319,700	\$(63,371)	\$(65,080)	\$992,904	\$989,981
Resource costs	239,900	258,147	190,061	187,846	(63,371)	(65,080)	366,590	380,913
Gross margin	\$485,795	\$477,214	\$140,519	\$131,854	\$—	\$—	\$626,314	\$609,068

The gross margin on electric sales increased \$8.6 million and the gross margin on natural gas sales increased \$8.7 million. The increase in electric gross margin was primarily due to a general rate increase in Idaho, customer growth and lower resource costs, partially offset by a change in the provision for earnings sharing. During 2016, there was a provision for earnings sharing, which increased electric gross margin by \$3.2 million, compared to a rebate during 2017 of \$0.1 million. For the nine months ended September 30, 2017, we recognized a pre-tax benefit of \$3.6 million under the ERM in Washington compared to a benefit of \$2.7 million for the nine months ended September 30, 2016. For the full year of 2017, we expect to be in a benefit position under the ERM within the \$4 million deadband, primarily due to above normal hydroelectric generation for the year, which allowed us to engage in additional optimization activities.

The increase in natural gas gross margin was primarily due to a general rate increase in Oregon and customer growth. Intracompany revenues and resource costs represent purchases and sales of natural gas between our natural gas distribution operations and our electric generation operations (as fuel for our generation plants). These transactions are eliminated in the presentation of total results for Avista Utilities and in the condensed consolidated financial statements but are included in the separate results for electric and natural gas presented below.

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The following graphs present our utility electric operating revenues and megawatt-hour (MWh) sales for the nine months ended September 30 (dollars in millions and MWhs in thousands):

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The following table presents Avista Utilities' decoupling and customer earnings sharing mechanisms by jurisdiction that are reflected in utility electric operating revenues for the nine months ended September 30 (dollars in thousands):

	Electric Operating Revenues	
	2017	2016
Washington		
Decoupling surcharge (rebate)	\$(5,552)	\$8,900
Provision for earnings sharing (1)	(130)	2,524
Idaho		
Decoupling surcharge (rebate)	\$(2,015)	\$4,516
Provision for earnings sharing (2)	n/a	711

The provision for earnings sharing in Washington for the nine months ended September 30, 2017 represents an adjustment of the 2016 provision for earnings sharing. We are not expecting a provision for earnings sharing in (1) Washington relating to 2017 earnings. The provision for earnings sharing in Washington for the nine months ended September 30, 2016 resulted from a \$2.5 million reduction in the 2015 provision for earnings sharing (which increased 2016 revenues).

The provision for earnings sharing in Idaho for the nine months ended September 30, 2016 resulted from a (2) reduction in the 2015 provision for earnings sharing (which increased 2016 revenues). Beginning in 2016 there is no longer an earnings sharing mechanism in Idaho.

(n/a) This mechanism did not exist during this time period.

Total electric revenues decreased \$9.7 million for the nine months ended September 30, 2017 as compared to the nine months ended September 30, 2016 primarily reflecting the following:

a \$42.2 million increase in retail electric revenue due to an increase in total MWhs sold (increased revenues \$30.5 million) and an increase in revenue per MWh (increased revenues \$11.7 million).

The increase in total retail MWhs sold was the result of weather that was cooler than the prior year during the heating season (which increased electric heating loads) and warmer than the prior year during the cooling season (which increased electric cooling loads), as well as customer growth. Compared to the nine months ended September 30, 2016, residential electric use per customer increased 9.8 percent and commercial use per customer increased 0.6 percent. Heating degree days in Spokane were 5 percent above normal and 26 percent above the first nine months of 2016. Year-to-date 2016 cooling degree days were 41 percent above normal and 57 percent above the prior year.