UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

FOR THE QUARTERLY PERIOD ENDED September 30, 2015 OR

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

FOR THE TRANSITION PERIOD FROM TO

Commission file number 1-3701

AVISTA CORPORATION

(Exact name of Registrant as specified in its charter)

Washington	**91-0462470**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
1411 East Mission Avenue, Spokane, Washington	**99202-2600**
(Address of principal executive offices)	**(Zip Code)**

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

None

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ☐

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

Large accelerated filer	x	Accelerated filer	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐

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

As of October 31, 2015, 62,306,897 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

AVISTA CORPORATION
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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,” “projects,” “predicts,” and similar expressions.

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

- 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;
- state and federal regulatory 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 and operating costs and discretion over allowed return on investment;
- 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 on wholesale energy transactions and credit risk to us from such transactions, and the market value of derivative assets and liabilities;
- 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;
- 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;
- the potential effects of legislation or administrative rulemaking, including possible effects on our generating resources of restrictions on greenhouse gas emissions to mitigate concerns over global climate changes;
- political pressures, activism, challenges in court or regulatory practices that could constrain or place additional cost burdens 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;
- 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;
- the outcome of pending legal proceedings arising out of the “western energy crisis” of 2000 and 2001, specifically related to the Pacific Northwest refund proceedings;
- the outcome of legal proceedings and other contingencies;

- changes in environmental and endangered species laws, regulations, decisions and policies, including present and potential environmental remediation costs and our compliance with these matters;
- 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;
- growth or decline of our customer base and the extent to which new uses for our services may materialize or existing uses may decline;
- the ability to comply with the terms of the licenses for our hydroelectric generating facilities at cost-effective levels;
- severe weather or natural disasters, including avalanches and wildfires, 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 distribution systems or other operations;
- public injuries or damage arising from or allegedly arising from our operations;
- blackouts or disruptions of interconnected transmission systems (the regional power grid);
- disruption to information systems, automated controls and other technologies that we rely on for our operations, communications and customer service;
- terrorist attacks, cyber attacks or other malicious acts that may disrupt or cause damage to our utility assets or to the national economy in general, including any effects of terrorism, cyber attacks or vandalism that damage or disrupt information technology systems;
- cyber attacks 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;
- delays or changes in construction costs, and/or our ability to obtain required permits and materials for present or prospective facilities;
- changes in the costs to implement new information technology systems and/or obstacles that impede our ability to complete such projects timely and effectively;
- 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;
- changes in industrial, commercial and residential growth and demographic patterns in our service territory or changes in demand by significant customers;
- the loss of key suppliers for materials or services or disruptions to the supply chain;
- default or nonperformance on the part of any parties from which we purchase and/or sell capacity or energy;
- deterioration in the creditworthiness of our customers;
- potential decline in our credit ratings, with effects including impeded access to capital markets, higher interest costs, and restrictive covenants in our financing arrangements and wholesale energy contracts;
- increasing health care costs and the resulting effect on employee injury costs and health insurance provided to our employees and retirees;
- increasing costs of insurance, more restrictive coverage terms and our ability to obtain insurance;
- 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;
- 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 technologies, possibly making some of the current technology obsolete;
- changes in tax rates and/or policies;

- 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 that we recover interest costs through utility operations;
- potential difficulties in integrating acquired operations and in realizing expected opportunities, diversions of management resources and losses of key employees, challenges with respect to operating new businesses and other unanticipated risks and liabilities;
- 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;
- compliance with extensive federal, state and local legislation and regulation, including numerous environmental, health, safety and other laws and regulations that affect our operations and costs; and
- adverse impacts to our Alaska operations because a majority of the hydroelectric power generation for such operations is provided by a single facility that is subject to a long-term power purchase agreement; hence any issues that negatively affect this facility’s ability to generate or transmit power, the cost and ability to replace power in the event of an extended outage, any decrease in the demand for the power generated by this facility or any loss by our subsidiary of its contractual rights with respect thereto or other adverse effects thereon could negatively affect our Alaska operations' financial results.

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. However, there can be no assurance that our expectations, beliefs or projections will be achieved or accomplished. Furthermore, any forward-looking statement speaks only as of the date on which such statement is made. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time to time, and it is not possible for us to predict all such factors, nor can we assess the effect of each such factor on our business or the extent that any such factor or combination of factors may cause actual results to differ materially from those contained in any forward-looking statement.

Available Information

Our website address is www.avistacorp.com. We make annual, quarterly and current reports available at our website as soon as practicable after electronically filing these reports with the Securities and Exchange Commission. Information contained on our website is not part of this report.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

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

	2015	2014
Operating Revenues:		
Utility revenues	$ 307,405	$ 291,262
Non-utility revenues	6,244	10,296
Total operating revenues	313,649	301,558
Operating Expenses:		
Utility operating expenses:		
Resource costs	138,210	131,588
Other operating expenses	74,315	72,509
Depreciation and amortization	36,303	33,294
Taxes other than income taxes	22,269	21,000
Non-utility operating expenses:		
Other operating expenses	6,462	10,251
Depreciation and amortization	178	154
Total operating expenses	277,737	268,796
Income from continuing operations	35,912	32,762
Interest expense	19,951	18,642
Interest expense to affiliated trusts	120	113
Capitalized interest	(905)	(1,212)
Other income-net	(2,123)	(2,608)
Income from continuing operations before income taxes	18,869	17,827
Income tax expense	6,115	7,301
Net income from continuing operations	12,754	10,526
Net income (loss) from discontinued operations (Note 4)	289	(55)
Net income	13,043	10,471
Net income attributable to noncontrolling interests	(32)	(20)
Net income attributable to Avista Corp. shareholders	$ 13,011	$ 10,451

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (continued)

Avista Corporation

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

	2015	2014
Amounts attributable to Avista Corp. shareholders:		
Net income from continuing operations attributable to Avista Corp. shareholders	$ 12,722	$ 10,506
Net income (loss) from discontinued operations attributable to Avista Corp. shareholders	289	(55)
Net income attributable to Avista Corp. shareholders	$ 13,011	$ 10,451
Weighted-average common shares outstanding (thousands), basic	62,299	63,934
Weighted-average common shares outstanding (thousands), diluted	62,688	64,244
Earnings per common share attributable to Avista Corp. shareholders, basic:		
Earnings per common share from continuing operations	$ 0.21	$ 0.16
Earnings per common share from discontinued operations	—	—
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 0.21	$ 0.16
Earnings per common share attributable to Avista Corp. shareholders, diluted:		
Earnings per common share from continuing operations	$ 0.21	$ 0.16
Earnings per common share from discontinued operations	—	—
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 0.21	$ 0.16
Dividends declared per common share	$ 0.33	$ 0.3175

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Nine Months Ended September 30
Dollars in thousands, except per share amounts
(Unaudited)

	2015	2014
Operating Revenues:		
Utility revenues	$ 1,074,642	$ 1,031,491
Non-utility revenues	22,829	29,225
Total operating revenues	1,097,471	1,060,716
Operating Expenses:		
Utility operating expenses:		
Resource costs	488,886	481,007
Other operating expenses	220,599	207,195
Depreciation and amortization	106,279	95,200
Taxes other than income taxes	75,424	70,513
Non-utility operating expenses:		
Other operating expenses	22,924	20,514
Depreciation and amortization	512	452
Total operating expenses	914,624	874,881
Income from continuing operations	182,847	185,835
Interest expense	59,719	55,933
Interest expense to affiliated trusts	347	336
Capitalized interest	(2,701)	(2,707)
Other income-net	(6,190)	(8,263)
Income from continuing operations before income taxes	131,672	140,536
Income tax expense	47,378	51,274
Net income from continuing operations	84,294	89,262
Net income from discontinued operations (Note 4)	485	70,772
Net income	84,779	160,034
Net income attributable to noncontrolling interests	(73)	(213)
Net income attributable to Avista Corp. shareholders	$ 84,706	$ 159,821

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (continued)

Avista Corporation

For the Nine Months Ended September 30
Dollars in thousands, except per share amounts
(Unaudited)

	2015	2014
Amounts attributable to Avista Corp. shareholders:		
Net income from continuing operations attributable to Avista Corp. shareholders	$ 84,221	$ 89,236
Net income from discontinued operations attributable to Avista Corp. shareholders	485	70,585
Net income attributable to Avista Corp. shareholders	$ 84,706	$ 159,821
Weighted-average common shares outstanding (thousands), basic	62,299	61,413
Weighted-average common shares outstanding (thousands), diluted	62,691	61,625
Earnings per common share attributable to Avista Corp. shareholders, basic:		
Earnings per common share from continuing operations	$ 1.35	$ 1.45
Earnings per common share from discontinued operations	0.01	1.15
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 1.36	$ 2.60
Earnings per common share attributable to Avista Corp. shareholders, diluted:		
Earnings per common share from continuing operations	$ 1.34	$ 1.45
Earnings per common share from discontinued operations	0.01	1.14
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 1.35	$ 2.59
Dividends declared per common share	$ 0.99	$ 0.9525

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

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

	2015	2014
Net income	$ 13,043	$ 10,471
Other Comprehensive Income:		
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $132 and $60, respectively	246	112
Total other comprehensive income	246	112
Comprehensive income	13,289	10,583
Comprehensive income attributable to noncontrolling interests	(32)	(20)
Comprehensive income attributable to Avista Corporation shareholders	$ 13,257	$ 10,563

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

	2015	2014
Net income	$ 84,779	$ 160,034
Other Comprehensive Income (Loss):		
Unrealized investment gains - net of taxes of $0 and $664, respectively	—	1,126
Reclassification adjustment for realized gains on investment securities included in net income from discontinued operations - net of taxes of $0 and $(1), respectively	—	(2)
Reclassification adjustment for realized losses on investment securities included in net income from discontinued operations - net of taxes of $0 and $273, respectively	—	462
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $396 and $181, respectively	737	335
Total other comprehensive income	737	1,921
Comprehensive income	85,516	161,955
Comprehensive income attributable to noncontrolling interests	(73)	(213)
Comprehensive income attributable to Avista Corporation shareholders	$ 85,443	$ 161,742

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands
(Unaudited)

		September 30, 2015		December 31, 2014
Assets:				
Current Assets:				
Cash and cash equivalents	$	9,314	$	22,143
Accounts and notes receivable-less allowances of $5,121 and $4,888, respectively		110,837		171,925
Utility energy commodity derivative assets		899		1,525
Regulatory asset for utility derivatives		16,841		29,640
Materials and supplies, fuel stock and stored natural gas		59,735		66,356
Deferred income taxes		20,646		14,794
Income taxes receivable		627		43,893
Other current assets		39,081		45,071
Total current assets		257,980		395,347
Net Utility Property:				
Utility plant in service		5,007,349		4,718,062
Construction work in progress		193,000		227,758
Total		5,200,349		4,945,820
Less: Accumulated depreciation and amortization		1,416,227		1,325,858
Total net utility property		3,784,122		3,619,962
Other Non-current Assets:				
Investment in exchange power-net		9,596		11,433
Investment in affiliated trusts		11,547		11,547
Goodwill		57,672		57,976
Long-term energy contract receivable		18,179		28,202
Other property and investments-net		43,591		42,016
Total other non-current assets		140,585		151,174
Deferred Charges:				
Regulatory assets for deferred income tax		95,535		100,412
Regulatory assets for pensions and other postretirement benefits		226,648		235,758
Other regulatory assets		94,124		91,920
Regulatory asset for unsettled interest rate swaps		87,973		77,063
Non-current regulatory asset for utility derivatives		34,018		24,483
Other deferred charges		18,221		16,212
Total deferred charges		556,519		545,848
Total assets	$	4,739,206	$	4,712,331

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

Dollars in thousands
(Unaudited)

	September 30, 2015	December 31, 2014
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 63,172	$ 112,974
Current portion of long-term debt and capital leases	93,105	6,424
Current portion of nonrecourse long-term debt of Spokane Energy	—	1,431
Short-term borrowings	130,000	105,000
Utility energy commodity derivative liabilities	15,092	18,045
Other current liabilities	146,368	141,395
Total current liabilities	447,737	385,269
Long-term debt and capital leases	1,391,611	1,492,062
Long-term debt to affiliated trusts	51,547	51,547
Regulatory liability for utility plant retirement costs	261,092	254,140
Pensions and other postretirement benefits	188,711	189,489
Deferred income taxes	724,473	710,342
Other non-current liabilities and deferred credits	165,838	146,240
Total liabilities	3,231,009	3,229,089
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; 62,303,857 and 62,243,374 shares issued and outstanding as of September 30, 2015 and December 31, 2014, respectively	1,002,716	999,960
Accumulated other comprehensive loss	(7,151)	(7,888)
Retained earnings	512,988	491,599
Total Avista Corporation shareholders' equity	1,508,553	1,483,671
Noncontrolling Interests	(356)	(429)
Total equity	1,508,197	1,483,242
Total liabilities and equity	$ 4,739,206	$ 4,712,331

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

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

	2015	2014
Operating Activities:		
Net income	$ 84,779	$ 160,034
Non-cash items included in net income:		
Depreciation and amortization	109,522	102,899
Provision for deferred income taxes	12,381	111,335
Power and natural gas cost amortizations (deferrals), net	10,004	(17,956)
Amortization of debt expense	2,651	2,799
Amortization of investment in exchange power	1,838	1,838
Stock-based compensation expense	5,263	6,261
Equity-related AFUDC	(5,891)	(6,426)
Pension and other postretirement benefit expense	28,179	17,381
Amortization of Spokane Energy contract	10,023	9,214
Gain on sale of Ecova	(710)	(161,100)
Other	(717)	14,568
Contributions to defined benefit pension plan	(12,000)	(32,000)
Changes in certain current assets and liabilities:		
Accounts and notes receivable	49,524	64,761
Materials and supplies, fuel stock and stored natural gas	6,621	(22,979)
Decrease (increase) in collateral posted for derivative instruments	(9,917)	5,978
Income taxes receivable	43,266	(645)
Other current assets	3,408	(1,886)
Accounts payable	(32,378)	(22,450)
Income taxes payable	158	6,885
Other current liabilities	5,240	27,203
Net cash provided by operating activities	311,244	265,714
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(272,801)	(229,764)
Other capital expenditures	(852)	(6,316)
Federal and state grant payments received	2,752	2,191
Cash received (paid) in acquisition, net	(95)	15,007
Increase in funds held for clients	—	(18,931)
Purchase of securities available for sale	—	(12,267)
Sale and maturity of securities available for sale	—	14,612
Proceeds from sale of Ecova, net of cash sold	—	229,903
Other	(106)	(1,194)
Net cash used in investing activities	(271,102)	(6,759)

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

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

	2015	2014
Financing Activities:		
Net increase (decrease) in short-term borrowings	$ 25,000	$ (136,000)
Repayment of borrowings from Ecova line of credit	—	(46,000)
Proceeds from issuance of long-term debt	—	75,000
Redemption and maturity of long-term debt	(2,174)	(39,367)
Maturity of nonrecourse long-term debt of Spokane Energy	(1,431)	(12,172)
Cash paid for settlement of interest rate swap agreements	(9,326)	—
Issuance of common stock, net of issuance costs	1,397	3,425
Repurchase of common stock	(2,920)	(60,963)
Cash dividends paid	(61,828)	(58,552)
Increase in client fund obligations	—	16,216
Payment to noncontrolling interests for sale of Ecova	—	(54,179)
Payment to option holders and redeemable noncontrolling interests for sale of Ecova	—	(20,871)
Other	(1,689)	2,325
Net cash used in financing activities	(52,971)	(331,138)
Net decrease in cash and cash equivalents	(12,829)	(72,183)
Cash and cash equivalents at beginning of period	22,143	82,574
Cash and cash equivalents at end of period	$ 9,314	$ 10,391

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS

Avista Corporation

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

	2015	2014
Common Stock, Shares:		
Shares outstanding at beginning of period	62,243,374	60,076,752
Shares issued	149,883	4,685,953
Shares repurchased	(89,400)	(1,924,077)
Shares outstanding at end of period	62,303,857	62,838,628
Common Stock, Amount:		
Balance at beginning of period	$ 999,960	$ 896,993
Equity compensation expense	4,579	6,061
Issuance of common stock, net of issuance costs and excess tax benefits	1,397	153,501
Payment of minimum tax withholdings for share-based payment awards	(1,832)	—
Repurchase of common stock	(1,431)	(30,794)
Equity transactions of consolidated subsidiaries	—	(1,062)
Payment to option holders and redeemable noncontrolling interests for sale of Ecova	—	(20,871)
Excess tax benefits	43	3,936
Balance at end of period	1,002,716	1,007,764
Accumulated Other Comprehensive Loss:		
Balance at beginning of period	(7,888)	(5,819)
Other comprehensive income	737	1,921
Balance at end of period	(7,151)	(3,898)
Retained Earnings:		
Balance at beginning of period	491,599	407,092
Net income attributable to Avista Corporation shareholders	84,706	159,821
Cash dividends paid (common stock)	(61,828)	(58,552)
Repurchase of common stock	(1,489)	(30,169)
Valuation adjustments and other noncontrolling interests activity	—	10,150
Balance at end of period	512,988	488,342
Total Avista Corporation shareholders’ equity	1,508,553	1,492,208
Noncontrolling Interests:		
Balance at beginning of period	(429)	20,001
Net income attributable to noncontrolling interests	73	217
Deconsolidation of noncontrolling interests related to sale of Ecova	—	(23,612)
Other	—	2,943
Balance at end of period	(356)	(451)
Total equity	$ 1,508,197	$ 1,491,757
Redeemable Noncontrolling Interests:		
Balance at beginning of period	$ —	$ 15,889
Net loss attributable to noncontrolling interests	—	(4)
Purchase of subsidiary noncontrolling interests	—	(12)
Valuation adjustments and other noncontrolling interests activity	—	(15,873)
Balance at end of period	$ —	$ —

The Accompanying Notes are an Integral Part of These Statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

The accompanying condensed consolidated financial statements of Avista Corporation (Avista Corp. or the Company) for the interim periods ended September 30, 2015 and 2014 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. 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, 2014 (2014 Form 10-K). Please refer to the section “Acronyms and Terms” in the 2014 Form 10-K for definitions of terms. 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.

On July 1, 2014, Avista Corp. acquired Alaska Energy and Resources Company (AERC), and as of that date, AERC became a wholly-owned subsidiary of Avista Corp. The primary subsidiary of AERC is Alaska Electric Light and Power Company (AEL&P), comprising the regulated utility operations in Alaska. There are no AERC earnings included in the overall results of Avista Corp. prior to July 1, 2014. See Note 3 for information regarding the acquisition of AERC.

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. During the first half of 2014, Avista Capital’s subsidiaries included Ecova, Inc. (Ecova), which was an 80.2 percent owned subsidiary prior to its disposition on June 30, 2014. Ecova was a provider of energy efficiency and other facility information and cost management programs and services for multi-site customers and utilities throughout North America. See Note 4 for information regarding the disposition of Ecova and Note 14 for business segment information.

Basis of Reporting

The condensed consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries and other majority owned subsidiaries and variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Ecova's revenues and expenses are included in the Condensed Consolidated Statements of Income in discontinued operations; however, as of June 30, 2014, and for all subsequent reporting periods, there are no balance sheet amounts included for Ecova. All tables throughout the Notes to Condensed Consolidated Financial Statements that present Condensed Consolidated Statements of Income information were revised to include only the amounts from continuing operations. 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 and totaled the following amounts for the three and nine months ended September 30 (dollars in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Utility taxes	$ 12,316	$ 11,716	$ 44,755	$ 43,923

Other Income-Net

Other income-net consisted of the following items for the three and nine months ended September 30 (dollars in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Interest income	$ 118	$ 154	$ 478	$ 678
Interest income on regulatory deferrals	10	59	44	154
Equity-related AFUDC	2,017	2,189	5,891	6,426
Net gain (loss) on investments	240	(27)	(211)	118
Other income (loss)	(262)	233	(12)	887
Total	$ 2,123	$ 2,608	$ 6,190	$ 8,263

Materials and Supplies, Fuel Stock and Stored Natural Gas

Inventories of materials and supplies, fuel stock and stored natural gas are recorded at average cost for our regulated operations and the lower of cost or market for our non-regulated operations and consisted of the following as of September 30, 2015 and December 31, 2014 (dollars in thousands):

	September 30, 2015	December 31, 2014
Materials and supplies	$ 34,957	$ 32,483
Fuel stock	4,802	5,142
Stored natural gas	19,976	28,731
Total	$ 59,735	$ 66,356

Investments and Funds Held for Clients and Client Fund Obligations

In connection with its bill paying services, Ecova collected funds from its clients and remitted the funds to the appropriate utility or other service provider. Some of the funds collected were invested by Ecova and classified as investments and funds held for clients, and a related liability for client fund obligations was recorded. Investments and funds held for clients included cash and cash equivalent investments, money market funds and investment securities classified as available for sale. Ecova did not invest the funds directly for the clients' benefit; therefore, Ecova bore the risk of loss associated with the investments. As of June 30, 2014 and for all subsequent reporting periods there are no longer any investments and funds held for clients due to the disposition of Ecova.

The following is a summary of the disposition of available-for-sale securities for the nine months ended September 30, 2014 (dollars in thousands):

	Nine months ended September 30, 2014
Proceeds from sales, maturities and calls	$ 14,612
Gross realized gains	3
Gross realized losses (1)	(735)

(1) The gross realized losses for the nine months ended September 30, 2014 were included in the determination of the gain on the disposition of Ecova and were not the result of selling any individual securities.

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Condensed Consolidated Balance Sheets measured at estimated fair value. In certain defined conditions, a derivative may be specifically designated as a hedge for a particular exposure. The accounting for a derivative depends on the intended use of such derivative and the resulting designation.

The Washington Utilities and Transportation Commission (UTC) and the Idaho Public Utilities Commission (IPUC) issued accounting orders authorizing Avista Utilities 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. The orders provide for Avista Utilities to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Condensed Consolidated Statements of Income. Realized gains or losses are recognized in the periods of delivery, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, 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 rates cases. Regulatory assets are assessed regularly and are probable for 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 agreements, each period Avista Utilities records all mark-to-market gains and losses as assets and liabilities and records offsetting regulatory assets and liabilities, such that there is no income statement impact. Upon settlement of interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the term of the associated debt.

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 swap agreements and foreign currency exchange contracts, are reported at estimated fair value on the Condensed Consolidated Balance Sheets. See Note 11 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits

The Company follows the accounting practices for regulated operations for its regulated utility businesses because:

- rates for regulated services are established by or subject to approval by independent third-party regulators,
- the regulated rates are designed to recover the cost of providing the regulated services, and
- in view of demand for the regulated services and the level of competition, it is reasonable to assume that rates can be charged to and collected from customers at levels that will recover costs.

Regulatory accounting practices require that certain costs and/or obligations (such as incurred power and natural gas costs not currently included in rates, but expected to be recovered or refunded in the future) are reflected as deferred charges or credits on the Condensed Consolidated Balance Sheets. These costs and/or obligations are not reflected in the Condensed Consolidated Statements of Income until the period during which matching revenues are recognized. The Company also has decoupling revenue deferrals. As opposed to cost deferrals which are not recognized in the Condensed Consolidated Statements of Income until they are included in rates, decoupling revenue is recognized in the Condensed Consolidated Statements of Income during the period it occurs (i.e. during the period of revenue shortfall or excess due to fluctuations in customer usage), subject to certain limitations, and a regulatory asset/liability is established which will be surcharged or rebated to customers in future periods. If at some point in the future the Company determines that it no longer meets the criteria for continued application of regulatory accounting practices for all or a portion of its regulated operations, the Company could be:

- required to write off its regulatory assets,
- precluded from the future deferral of costs or decoupled revenues not recovered through rates at the time such amounts are incurred, even if the Company expected to recover these amounts from customers in the future.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax, consisted of the following as of September 30, 2015 and December 31, 2014 (dollars in thousands):

	September 30, 2015	December 31, 2014
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $(3,852) and $(4,247), respectively	$ (7,151)	$ (7,888)

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). Items in parenthesis indicate reductions to net income.

	Amounts Reclassified from Accumulated Other Comprehensive Loss				
	Three months ended September 30,		Nine months ended September 30,		
Details about Accumulated Other Comprehensive Loss Components	2015	2014	2015	2014	Affected Line Item in Statement of Income
Realized gains on investment securities	$ —	$ —	$ —	$ 3	(a)
Realized losses on investment securities	—	—	—	(735)	(a)
	—	—	—	(732)	Total before tax
	—	—	—	272	Tax benefit (a)
	$ —	$ —	$ —	$ (460)	Net of tax
Amortization of defined benefit pension items					
Amortization of net prior service cost	$ 273	$ 37	$ 819	$ 113	(b)
Amortization of net loss	(3,688)	(1,988)	$ (11,063)	$ (5,968)	(b)
Adjustment due to effects of regulation	3,037	1,779	9,111	5,339	(b)
	(378)	(172)	(1,133)	(516)	Total before tax
	132	60	396	181	Tax benefit
	$ (246)	$ (112)	$ (737)	$ (335)	Net of tax

(a) These amounts were included as part of net income from discontinued operations (see Note 4 for additional details).
(b) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 7 for additional details).

Appropriated Retained Earnings

In accordance with the hydroelectric licensing requirements of section 10(d) of the Federal Power Act (FPA), the Company maintains an appropriated retained earnings account for any earnings in excess of the specified rate of return on the Company's investment in the licenses for its various hydroelectric projects. Per section 10(d) of the FPA, the Company must maintain these excess earnings in an appropriated retained earnings account until the termination of the licensing agreements or apply them to reduce the net investment in the licenses of the hydroelectric projects at the discretion of the FERC. The Company typically calculates the earnings in excess of the specified rate of return on an annual basis, usually during the second quarter.

In addition to the hydroelectric project licenses identified above for Avista Utilities, the requirements of section 10(d) of the FPA also apply to the AEL&P licenses for Lake Dorothy and Annex Creek/Salmon Creek (combined).

The appropriated retained earnings amounts included in retained earnings were as follows as of September 30, 2015 and December 31, 2014 (dollars in thousands):

	September 30, 2015	December 31, 2014
Appropriated retained earnings	$ 21,030	$ 14,270

Dividends

The payment of dividends on common stock could be limited by:

- certain covenants applicable to preferred stock (when outstanding) contained in the Company’s Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements,
- the hydroelectric licensing requirements of section 10(d) of the FPA, and
- certain requirements under the Public Utility Commission of Oregon (OPUC) approval of the AERC acquisition. As of July 1, 2015 (one year following the acquisition date), the OPUC does not permit one-time or special dividends from AERC to Avista Corp. and does not permit Avista Utilities' total equity to total capitalization to be

less than 40 percent, without approval from the OPUC. However, the OPUC approval does allow for regular distributions of AERC earnings to Avista Corp. as long as AERC remains sufficiently capitalized and insured.

Under the covenant applicable to the Company's committed line of credit agreement, which does not permit the ratio of “consolidated total debt” to “consolidated total capitalization” to be greater than 65 percent at any time, the amount of retained earnings available for dividends at September 30, 2015 was limited to approximately $397.4 million.

Under the requirements of the OPUC approval of the AERC acquisition as outlined above, the amount available for dividends at September 30, 2015 was limited to approximately $252.2 million.

Stock Repurchase Program

On December 16, 2014, the Company announced that Avista Corp.'s Board of Directors approved the repurchase of up to 800,000 shares of the Company’s outstanding common stock, commencing on January 2, 2015, and expiring on March 31, 2015 (first quarter 2015 program). Under the first quarter 2015 program, the Company repurchased 89,400 shares at a total cost of $2.9 million and an average cost of $32.66 per share. All repurchased shares reverted to the status of authorized but unissued shares.

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 losses that do not meet these conditions for accrual if there is a reasonable possibility that a loss may be incurred. As of September 30, 2015, the Company has not recorded any significant amounts related to unresolved contingencies.

Reclassifications

Certain prior year amounts on the Company's Condensed Consolidated Statements of Cash Flows were reclassified to conform to the current year presentation. In the current year Condensed Consolidated Statements of Cash Flows, "Decrease (increase) in collateral posted for derivative instruments" and "Income taxes receivable" were added as their own line items. These were previously included in "Other current assets" in the operating activities section.

NOTE 2. NEW ACCOUNTING STANDARDS

In April 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-08, "Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity." This ASU amends the definition of a discontinued operation and requires entities to provide additional disclosures about discontinued operations as well as disposal transactions that do not meet the discontinued-operations criteria. ASU 2014-08 makes it more difficult for a disposal transaction to qualify as a discontinued operation. In addition, the ASU requires entities to reclassify assets and liabilities of a discontinued operation for all comparative periods presented in the Balance Sheet rather than just the current period, and it requires additional disclosures on the face of the Statement of Cash Flows regarding discontinued operations. This ASU became effective for periods beginning on or after December 15, 2014; however, early adoption was permitted. The Company evaluated this standard and determined that it would not early adopt this standard. Since the disposition of Ecova occurred before the effective date of this standard, and the Company did not early adopt this standard, there is no impact on the Company's financial condition, results of operations and cash flows in the current year.

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," 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 identifies the various performance obligations in a contract, allocates the transaction price among the performance obligations and recognizes revenue as the entity satisfies the performance obligations. This ASU was originally effective for periods beginning after December 15, 2016 and early adoption is not permitted. In August 2015, the FASB issued ASU 2015-14 Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," which deferred the effective date of ASU 2014-09 for one year, with adoption as of the original date permitted. However, while this ASU is not effective until 2018, it will require retroactive application to all periods presented in the financial statements. As such, at adoption in 2018, amounts in 2016 and 2017 may have to be revised or a cumulative adjustment to opening retained earnings may have to be recorded. The Company is evaluating this standard and cannot, at this time, estimate the potential impact on its future financial condition, results of operations and cash flows.

In February 2015, the FASB issued ASU No. 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis." This ASU significantly changes the consolidation analysis required under GAAP, including the identification of variable interest entities (VIE). The ASU also removes the deferral of the VIE analysis related to investments in certain investment funds, which will result in a different consolidation evaluation for these types of investments. This ASU is effective for periods beginning on or after December 15, 2015; however, early adoption is permitted. The Company evaluated this standard and determined that it will not early adopt this standard. The Company is evaluating this standard and cannot, at this time, estimate the potential impact on its future financial condition, results of operations and cash flows.

In April 2015, the FASB issued ASU No. 2015-03, "Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs." This ASU amends the presentation of debt issuance costs in the financial statements such that an entity presents such costs in the balance sheet as a direct deduction from the related debt liability rather than as a deferred asset. Amortization of the costs will continue to be reported as interest expense. ASU No. 2015-03 is effective for periods beginning on or after December 15, 2015; however, early adoption is permitted. Upon adoption, entities will apply the new guidance retrospectively to all comparable prior periods presented in the financial statements. The Company is currently evaluating this standard and has not determined if it will early adopt this standard. Upon adoption, the Company will revise its current presentation of debt issuance costs for long-term debt in the Condensed Consolidated Balance Sheets; however, the Company does not expect a material impact on its future financial condition, results of operations or cash flows as a result of the adoption.

ASU No. 2015-03 did not address the presentation of debt issuance costs associated with line of credit arrangements. Accordingly, in August 2015, the FASB issued ASU No. 2015-15, "Interest - Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements." This ASU incorporates guidance from the Securities and Exchange Commission which states that it would not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line of credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. This ASU was effective upon issuance. The presentation outlined in ASU No. 2015-15 is consistent with the Company's current presentation of line of credit issuance costs; therefore, there is no impact to the Company's financial statements as a result of adopting this accounting standard in 2015.

In April 2015, the FASB issued ASU No. 2015-05, "Intangibles - Goodwill and Other - Internal-Use Software (Subtopic 350-40): Customer’s Accounting for Fees Paid in a Cloud Computing Arrangement." This ASU provides guidance on how organizations should account for fees paid in a cloud computing arrangement, including helping organizations understand whether their arrangement includes a software license. If the arrangement includes a software license, the software license would be accounted for in a manner consistent with internal-use software. If a cloud-computing arrangement does not include a software license, the customer is required to account for the arrangement as a service contract. This ASU is effective for periods beginning on or after December 15, 2015; however, early adoption is permitted. The Company evaluated this standard and determined that it will not early adopt this standard. Upon adoption, an entity can elect to apply this ASU prospectively or retroactively and disclose the method selected. The Company is evaluating this standard and cannot, at this time, estimate the potential impact on its future financial condition, results of operations and cash flows.

In May 2015, the FASB issued ASU No. 2015-07, "Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)." This ASU removes, from the fair value hierarchy,
investments for which the practical expedient is used to measure fair value at net asset value (NAV). Instead, an entity is required to include those investments as a reconciling line item so that the total fair value amount of investments in the disclosure is consistent with the amount on the balance sheet. Further, entities must provide certain disclosures for investments for which they elect to use the NAV practical expedient to determine fair value. This ASU is effective for periods beginning on or after December 15, 2015 and early adoption is permitted. The Company evaluated this standard and determined that it will not early adopt this standard. Upon adoption, this ASU should be applied retrospectively to all periods presented. The Company is evaluating this standard and cannot, at this time, estimate the potential impact on its future financial condition, results of operations and cash flows.

In July 2015, the FASB issued ASU No. 2015-11, "Inventory (Topic 330): Simplifying the Measurement of Inventory." This ASU simplifies the inventory measurement guidance by removing the requirement to measure inventory at the lower of cost or market and instead requires inventory to be measured at the lower of cost or net realizable value (estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation). This ASU applies to all inventory except that which is measured using last-in, first-out (LIFO) or the retail inventory method. Inventory measured using first-in, first-out (FIFO) or average cost is included in the new amendment. This ASU is effective for periods beginning on or after December 15, 2016. The new guidance shall be applied prospectively, and earlier application is permitted as of the beginning of an interim or annual reporting period. The Company is evaluating this standard and cannot, at this time, estimate the potential impact on its future financial condition, results of operations and cash flows. However, the Company does not expect to early adopt this standard.

NOTE 3. BUSINESS ACQUISITIONS

Alaska Energy and Resources Company

On July 1, 2014, the Company acquired AERC, based in Juneau, Alaska, and as of that date, AERC became a wholly-owned subsidiary of Avista Corp.

The primary subsidiary of AERC is AEL&P, a regulated utility which provides electric services to 16,676 customers in the City and Borough of Juneau (Juneau), Alaska. In addition to the regulated utility, AERC owns AJT Mining, which is an inactive mining company holding certain properties.

The purpose of the acquisition was to expand and diversify Avista Corp.'s energy assets and deliver long-term value to its customers, communities and investors.

In connection with the closing, on July 1, 2014 Avista Corp. issued 4,500,014 new shares of common stock to the shareholders of AERC based on a contractual formula that resulted in a price of $32.46 per share, reflecting a purchase price of $170.0 million, plus acquired cash, less outstanding debt and other closing adjustments.

The $32.46 price per share of Avista Corp. common stock was determined based on the average closing stock price of Avista Corp. common stock for the 10 consecutive trading days immediately preceding, but not including, the trading day prior to July 1, 2014. This value was used solely for determining the number of shares to issue based on the adjusted contract closing price (see reconciliation below). The fair value of the consideration transferred at the closing date was based on the closing stock price of Avista Corp. common stock on July 1, 2014, which was $33.35 per share.

On October 1, 2014, a working capital adjustment was made in accordance with the agreement and plan of merger which resulted in Avista Corp. issuing an additional 1,427 shares of common stock to the shareholders of AERC. The number of shares issued on October 1, 2014 was based on the same contractual formula described above. The fair value of the new shares issued in October was $30.71 per share, which was the closing stock price of Avista Corp. common stock on that date.

The contract acquisition price and the fair value of consideration transferred for AERC were as follows (in thousands, except "per share" and number of shares data):

Contract acquisition price (using the calculated $32.46 per share common stock price)		
Gross contract price	$	170,000
Acquired cash		19,704
Acquired debt (excluding capital lease obligation)		(38,832)
Other closing adjustments		(58)
Total adjusted contract price	$	150,814
Fair value of consideration transferred		
Avista Corp. common stock (4,500,014 shares at $33.35 per share)	$	150,075
Avista Corp. common stock (1,427 shares at $30.71 per share)		44
Cash		4,792
Fair value of total consideration transferred	$	154,911

During the second quarter of 2015, the Company recorded a reduction to goodwill of approximately $0.3 million due to income tax related adjustments. After consideration of the goodwill adjustment in the second quarter of 2015, the transaction resulted in a total amount of goodwill of $52.4 million. The goodwill associated with this acquisition is not deductible for tax purposes. The remainder of the assets acquired and liabilities assumed have not changed from the amounts disclosed in the 2014 Form 10-K.

The majority of AERC’s operations are subject to the rate-setting authority of the Regulatory Commission of Alaska (RCA) and are accounted for pursuant to GAAP, including the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for AERC’s regulated operations provide revenues derived from costs, including a return on investment, of assets and liabilities included in rate base. Due to this regulation, the fair values of AERC’s assets and liabilities subject to these rate-setting provisions are assumed to approximate their carrying values. There were not any identifiable intangible assets associated with this acquisition. The excess of the purchase consideration over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill at the acquisition date. The goodwill reflects the value paid for the expected continued growth of a rate-regulated business located in a defined service area with a constructive regulatory environment, the attractiveness of stable, growing cash flows, as well as providing a platform for potential future growth outside of the rate-regulated electric utility in Alaska and potential additional utility investment.

The following table summarizes the supplemental pro forma information for the three and nine months ended September 30, 2014 compared to actual 2015 information related to the acquisition of AERC as if the acquisition had occurred on January 1, 2013 (dollars in thousands - unaudited):

	Three months ended September 30,		Nine months ended September 30,	
	2015 Actual	2014 Actual	2015 Actual	2014 Pro forma
Actual Avista Corp. revenues from continuing operations (excluding AERC)	$ 304,342	$ 292,334	$ 1,065,126	$ 1,051,492
Total AERC revenues (1)	9,307	9,224	32,345	35,319
Total pro forma revenues	313,649	301,558	1,097,471	1,086,811
Actual AERC revenues included in Avista Corp. revenues (1)	9,307	9,224	32,345	9,224
Actual Avista Corp. net income from continuing operations attributable to Avista Corp. shareholders (excluding AERC)	12,422	9,982	80,562	88,712
Actual Avista Corp. net income (loss) from discontinued operations attributable to Avista Corp. shareholders	289	(55)	485	70,585
Adjustment to Avista Corp.'s net income for acquisition costs (net of tax) (2)	—	401	21	838
Supplemental pro forma AERC net income (1)	300	524	3,659	6,151
Total pro forma net income	13,011	10,852	84,727	166,286
Actual AERC net income included in Avista Corp. net income (1)	$ 300	$ 524	$ 3,659	$ 524

(1) AERC was acquired on July 1, 2014; therefore, all the revenues and net income for the third quarter of 2014 are actual amounts that are included in Avista Corp.'s overall results. All revenue and net income amounts prior to July 1, 2014 are supplemental pro forma amounts and are excluded from Avista Corp.'s overall results. The amounts disclosed for the three and nine months ended September 30, 2015 were included in the overall results of Avista Corp.

(2) This adjustment is to treat all transaction costs as if they occurred on January 1, 2013 and to remove them from the periods in which they actually occurred. The transaction costs were expensed and presented in the Condensed Consolidated Statements of Income in other operating expenses within utility operating expenses. Since the start of the transaction through September 30, 2015, Avista Corp. has expensed $3.0 million (pre-tax) in total transaction fees. In addition to the amounts expensed, through September 30, 2015, Avista Corp. has included $0.4 million in fees associated with the issuance of common stock for the transaction as a reduction to common stock. These fees do not impact the supplemental pro forma information above.

NOTE 4. DISCONTINUED OPERATIONS

On June 30, 2014, Avista Capital, completed the sale of its interest in Ecova to Cofely USA Inc., an indirect subsidiary of GDF SUEZ, a French multinational utility company, and an unrelated party to Avista Corp. The sale price was $335.0 million in cash, less the payment of debt and other customary closing adjustments. At the closing of the transaction on June 30, 2014, Ecova became a wholly-owned subsidiary of Cofely USA Inc. and the Company has not had and will not have any further involvement with Ecova after such date.

Avista Capital and Cofely USA Inc. agreed to make an election under Section 338(h)(10) of the Internal Revenue Code (Code) of 1986, as amended, with respect to the purchase and sale of Ecova to allocate the merger consideration among the assets of Ecova deemed to have been acquired in the merger.

The purchase price of $335.0 million, as adjusted, was divided among the security holders of Ecova, including minority shareholders, option holders and a warrant holder, pro rata based on ownership. Approximately $16.8 million (5 percent of the purchase price) was held in escrow for 15 months from the closing of the transaction to satisfy certain indemnification obligations under the merger agreement (Escrow). An additional $1.0 million was held in escrow pending resolution of adjustments to working capital. The indemnification escrow and the working capital adjustment escrow amounts above represent the full amounts to be divided among all security holders pro rata based on ownership.

As expected, no claims were made against the Escrow as of September 30, 2015 (the end of the claims period) and accordingly, all Escrow amounts were released in October 2015 and the Company received its full portion of the Escrow proceeds together with the remainder of the working capital adjustment escrow for a total amount of $13.8 million. After consideration of the escrow amounts received, the sales transaction provided cash proceeds to Avista Corp., net of debt, payment to option and minority holders, income taxes and transaction expenses, of $143.9 million and resulted in a net gain of $70.2 million. Almost all of the net gain was recognized in 2014 with some minor true-ups during 2015.

Prior to the completion of the sale, Ecova was a reportable business segment. Amounts reported in discontinued operations for 2014 and 2015 relate solely to the Ecova business segment. The following table presents amounts that were included in discontinued operations for the three and nine months ended September 30 (dollars in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Revenues	$ —	$ —	$ —	$ 87,534
Gain on sale of Ecova (1)	547	—	710	161,100
Transaction expenses and accelerated employee benefits (2)	24	86	24	9,062
Gain on sale of Ecova, net of transaction expenses	523	(86)	686	152,038
Income (loss) before income taxes	523	(86)	686	156,513
Income tax expense (benefit) (3)	234	(31)	201	85,741
Net income (loss) from discontinued operations	289	(55)	485	70,772
Net income attributable to noncontrolling interests	—	—	—	(187)
Net income (loss) from discontinued operations attributable to Avista Corp. shareholders	$ 289	$ (55)	$ 485	$ 70,585

(1) The gain recognized during 2015 relates to the resolution of the working capital adjustment, as well as a gain associated with the favorable settlement of outstanding litigation at Ecova that was shared between the Cofely USA, Inc. and the former shareholders and option holders of Ecova.

(2) Avista Corp.'s portion of the total transaction expenses was $9.1 million (including amounts which were withheld from the transaction net proceeds) and this was recognized during the second and third quarters of 2014 and the third quarter of 2015. All transaction expenses paid on the Ecova sale (including Avista Corp.'s portion and the portion attributable to the minority interest holders of Ecova) were $11.0 million, and of this amount, $5.4 million was withheld from the net proceeds and the remainder was paid during the second and third quarters of 2014 and the third quarter of 2015. The transaction expenses were for legal, accounting and other consulting fees, and the accelerated employee benefits related to employee stock options which were settled in accordance with the Ecova equity plan.

(3) The tax expense during 2015 resulted from a state tax true-up, partially offset by tax expense associated with the gain on sale and the final true-up of 2014 federal tax payments.

NOTE 5. DERIVATIVES AND RISK MANAGEMENT

The below disclosures in Note 5 apply only to Avista Corp. and Avista Utilities; AERC and its primary subsidiary AEL&P do not enter into derivative instruments.

Energy Commodity Derivatives

Avista Utilities is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Utilities utilizes derivative instruments, such as forwards, futures, swaps and options in order to manage the various risks relating to these commodity price exposures. The Company has an energy resources risk policy and control procedures to manage these risks. The Company’s Risk Management Committee establishes the Company’s energy resources risk policy and monitors compliance. The Risk Management Committee is comprised of certain Company officers and other members of management. The Audit Committee of the Company’s Board of Directors periodically reviews and discusses enterprise risk management processes, and it focuses on the Company's material financial and accounting risk exposures and the steps management has undertaken to control them.

As part of the Company's resource procurement and management operations in the electric business, the Company engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve the Company's load obligations and the use of these resources to capture available economic value. The Company 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 the related financial risks. These transactions range from terms of intra-hour up to multiple years.

Avista Utilities makes continuing projections of:

- electric loads at various points in time (ranging from intra-hour to multiple years) based on, among other things, estimates of customer usage and weather, historical data and contract terms, and
- resource availability at these points in time based on, among other things, fuel choices and fuel markets, estimates of streamflows, availability of generating units, historic and forward market information, contract terms, and experience.

On the basis of these projections, the Company makes purchases and sales of electric capacity and energy, fuel for electric generation, and related derivative instruments to match expected resources to expected electric load requirements and reduce exposure to electricity (or fuel) market price changes. Resource optimization involves generating plant dispatch and scheduling available resources and also includes transactions such as:

- purchasing fuel for generation,
- when economic, selling fuel and substituting wholesale electric purchases, and
- other wholesale transactions to capture the value of generation and transmission resources and fuel delivery capacity contracts.

Avista Utilities' optimization process includes entering into hedging transactions to manage risks. Transactions include both physical energy contracts and related derivative financial instruments.

As part of its resource procurement and management of its natural gas business, Avista Utilities 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 Utilities' distribution system. However, daily variations in natural gas demand can be significantly different than monthly demand projections. On the basis of these projections, Avista Utilities 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 Utilities also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets.

Natural gas resource optimization activities include:

- wholesale market sales of surplus natural gas supplies,
- optimization of interstate pipeline transportation capacity not needed to serve daily load, and
- purchases and sales of natural gas to optimize use of storage capacity.

The following table presents the underlying energy commodity derivative volumes as of September 30, 2015 that are expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWH	Financial (1) MWH	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWH	Financial (1) MWH	Physical (1) mmBTUs	Financial (1) mmBTUs
2015	171	805	8,962	50,538	39	1,142	1,683	32,768
2016	394	1,642	10,600	118,228	256	2,365	1,370	91,398
2017	397	—	675	35,823	286	483	1,360	19,008
2018	397	—	—	10,288	286	—	1,360	2,738
2019	235	—	—	4,500	158	—	1,345	—
Thereafter	—	—	—	—	—	—	2,470	—

(1) Physical transactions represent commodity transactions in which Avista Utilities will take or make delivery of either electricity or natural gas; financial transactions represent derivative instruments with delivery of cash in the amount of gain or loss but with no physical delivery of the commodity, such as futures, swaps, 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 PGAs), or in the general rate case process, and are expected to be collected through retail rates from customers.

Foreign Currency Exchange Contracts

A significant portion of Avista Utilities’ 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 Utilities’ 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 Utilities hedges a portion of the foreign currency risk by purchasing Canadian currency contracts when such commodity transactions are initiated. This risk has not had a material effect on the Company’s financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations were included with natural gas supply costs for ratemaking.

The following table summarizes the foreign currency hedges that the Company has outstanding as of September 30, 2015 and December 31, 2014 (dollars in thousands):

	September 30, 2015	December 31, 2014
Number of contracts	23	18
Notional amount (in United States currency)	$ 10,140	$ 5,474
Notional amount (in Canadian currency)	13,438	6,198

Interest Rate Swap Agreements

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt and future borrowing requirements. The Finance Committee of the Board of Directors periodically reviews and discusses interest rate risk management processes and focuses on the steps management has undertaken to manage it. The Company's Risk Management Committee also reviews the interest rate risk management plan. Avista Corp. manages interest rate exposure by limiting the variable rate exposures to a percentage of total capitalization. Additionally, interest rate risk is managed by monitoring market conditions when timing the issuance of long-term debt and optional debt redemptions and through the use of fixed rate long-term debt with varying maturities. The Company also hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swaps and U.S. Treasury lock agreements. These interest rate swaps and U.S. Treasury lock agreements are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

The following table summarizes the interest rate swaps that the Company has entered into as of September 30, 2015 and December 31, 2014 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
September 30, 2015	6	115,000	2016
	3	45,000	2017
	11	245,000	2018
	1	20,000	2019
December 31, 2014	5	75,000	2015
	5	95,000	2016
	3	45,000	2017
	9	205,000	2018

During the third quarter 2015, in connection with the execution of a purchase agreement for bonds that the Company will issue in December 2015, the Company cash-settled five interest rate swap contracts (notional aggregate amount of $75.0 million) and paid a total of $9.3 million. Upon settlement of interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the term of the associated debt.

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

Summary of Outstanding Derivative Instruments

As of September 30, 2015, the Company has multiple master netting agreements with a variety of entities that allow for cross-commodity netting under ASC 815-10-45. The Company does not have any agreements which allow for cross-affiliate netting among multiple affiliated legal entities. The amounts recorded on the Condensed Consolidated Balance Sheet as of September 30, 2015 and December 31, 2014 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, 2015 (in thousands):

		Fair Value			
Derivative	Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet
Foreign currency contracts	Other current liabilities	$ 8	$ (73)	$ —	$ (65)
Interest rate contracts	Other current liabilities	—	(7,344)	—	(7,344)
Interest rate contracts	Other non-current liabilities and deferred credits	1,002	(81,631)	36,270	(44,359)
Commodity contracts	Current utility energy commodity derivative assets	900	(1)	—	899
Commodity contracts	Current utility energy commodity derivative liabilities	60,218	(77,958)	2,648	(15,092)
Commodity contracts	Other non-current liabilities and deferred credits	15,007	(49,025)	9,944	(24,074)
Total derivative instruments recorded on the balance sheet		$ 77,135	$ (216,032)	$ 48,862	$ (90,035)

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of December 31, 2014 (in thousands):

		Fair Value			
Derivative	Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet
Foreign currency contracts	Other current liabilities	$ 1	$ (21)	$ —	$ (20)
Interest rate contracts	Other current assets	966	(506)	—	460
Interest rate contracts	Other current liabilities	—	(7,325)	—	(7,325)
Interest rate contracts	Other non-current liabilities and deferred credits	—	(69,737)	28,880	(40,857)
Commodity contracts	Current utility energy commodity derivative assets	2,063	(538)	—	1,525
Commodity contracts	Current utility energy commodity derivative liabilities	66,421	(97,586)	13,120	(18,045)
Commodity contracts	Other non-current liabilities and deferred credits	29,594	(54,077)	2,390	(22,093)
Total derivative instruments recorded on the balance sheet		$ 99,045	$ (229,790)	$ 44,390	$ (86,355)

Exposure to Demands for Collateral

The Company'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 the Company's credit ratings or changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against the Company's credit facilities and cash. The Company actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements.

The following table presents the Company's collateral outstanding related to its derivative instruments as of September 30, 2015 and December 31, 2014 (in thousands):

	September 30, 2015	December 31, 2014
Energy commodity derivatives		
Cash collateral posted	$ 23,093	$ 20,565
Letters of credit outstanding	26,200	14,500
Balance sheet offsetting (cash collateral against net derivative positions)	12,592	15,510
Interest rate swaps		
Cash collateral posted	36,270	28,880
Letters of credit outstanding	10,700	10,900
Balance sheet offsetting (cash collateral against net derivative positions)	36,270	28,880

Certain of the Company’s derivative instruments contain provisions that require the Company to maintain an "investment grade" credit rating from the major credit rating agencies. If the Company’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 the Company could be required to post as of September 30, 2015 and December 31, 2014 (in thousands):

	September 30, 2015	December 31, 2014
Energy commodity derivatives		
Liabilities with credit-risk-related contingent features	$ 8,436	$ 12,911
Additional collateral to post	8,433	16,227
Interest rate swaps		
Liabilities with credit-risk-related contingent features	88,975	77,568
Additional collateral to post	21,330	19,404

Credit Risk

Credit risk relates to the potential losses that the Company would incur as a result of non-performance by counterparties of their contractual obligations to deliver energy or make financial settlements. The Company often extends credit to counterparties and customers and is exposed to the risk that it may not be able to collect amounts owed to the Company. Credit risk includes potential counterparty default due to circumstances:

- relating directly to it,
- caused by market price changes, and
- relating to other market participants that have a direct or indirect relationship with such counterparty.

Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established. Should a counterparty fail to perform, the Company may be required to honor the underlying commitment or to replace existing contracts with contracts at then-current market prices.

The Company enters into bilateral transactions with various counterparties. The Company also trades energy and related derivative instruments through clearinghouse exchanges.

The Company seeks to mitigate bilateral credit risk by:

- entering into bilateral contracts that specify credit terms and protections against default,
- applying credit limits and duration criteria to existing and prospective counterparties,
- actively monitoring current credit exposures,
- asserting our collateral rights with counterparties,
- carrying out transaction settlements timely and effectively, and
- conducting transactions on exchanges with fully collateralized clearing arrangements that significantly reduce counterparty default risk.

The Company's credit policy requires an evaluation of the financial condition of counterparties. Credit risk management includes collateral requirements or other credit enhancements, such as letters of credit or parent company guarantees. The Company enters into various agreements that address credit risks including standardized agreements that allow for the netting or offsetting of positive and negative exposures.

The Company has concentrations of suppliers and customers in the electric and natural gas industries including:

- electric and natural gas utilities,
- electric generators and transmission providers,
- natural gas producers and pipelines,
- financial institutions including commodity clearing exchanges and related parties, and
- energy marketing and trading companies.

In addition, the Company has concentrations of credit risk related to geographic location as it operates in the western United States and western Canada. These concentrations of counterparties and concentrations of geographic location may impact the Company’s overall exposure to credit risk because the counterparties may be similarly affected by changes in conditions.

The Company maintains credit support agreements with certain counterparties and margin calls are periodically made and/or received. Margin calls are triggered when exposures exceed contractual limits or when there are changes in a counterparty’s creditworthiness. Price movements in electricity and natural gas can generate exposure levels in excess of these contractual limits. Negotiating for collateral in the form of cash, letters of credit, or performance guarantees is common industry practice.

NOTE 6. ASSET RETIREMENT OBLIGATIONS

The Company records the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred. When the liability is initially recorded, the associated costs of the ARO are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. In addition, if there are changes in the estimated timing or estimated costs of the AROs, adjustments are recorded during the period new information becomes available as an increase or decrease to the liability, with the offset recorded to the related long-lived asset. Upon retirement of the asset, the Company either settles the ARO for its recorded amount or incurs a gain or loss. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and AROs recorded since asset retirement costs are recovered through rates charged to customers.

Specifically, the Company has recorded liabilities for future AROs to:

- restore containment ponds at Colstrip,
- cap a landfill at the Kettle Falls Plant,
- remove plant and restore the land at the Coyote Springs 2 site at the termination of the land lease, and
- dispose of PCBs in certain transformers.

Due to an inability to estimate a range of settlement dates, the Company cannot estimate a liability for the:

- removal and disposal of certain transmission and distribution assets, and
- abandonment and decommissioning of certain hydroelectric generation and natural gas storage facilities.

On April 17, 2015, the EPA published a final rule regarding coal combustion residuals (CCRs), also termed coal combustion byproducts or coal ash in the Federal Register and this rule became effective on October 15, 2015. Colstrip, of which Avista Corp. is a 15 percent owner of units 3 and 4, produces this byproduct. The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste. The Company, in conjunction with the other Colstrip Owners, is developing a multi-year compliance plan to strategically address the new CCR requirements and existing State obligations while maintaining operational stability. During the second quarter of 2015, the operator of Colstrip provided an initial cost estimate of the expected retirement costs associated with complying with the new CCR rule. Based on the initial assessment, Avista Corp. recorded an increase to its ARO of $11.7 million with a corresponding increase in the cost basis of the utility plant.

The actual asset retirement costs related to the new CCR rule requirements may vary substantially from the estimates used to record the increased obligation due to uncertainty about the compliance strategies that will be used and the preliminary nature of available data used to estimate costs, such as the quantity of coal ash present at certain sites and the volume of fill that will be needed to cap and cover certain impoundments. Avista Corp. will coordinate with the plant operator and continue to gather additional data in future periods to make decisions about compliance strategies and the timing of closure activities. As additional information becomes available, Avista Corp. will update the ARO for these changes in estimates, which could be material. The Company expects to seek recovery of any increased costs related to complying with the new rule through customer rates.

There were no material changes to the ARO during all of 2014. The following table documents the changes in the Company’s ARO for the period December 31, 2014 through September 30, 2015 (dollars in thousands):

	2015
ARO at December 31, 2014	$ 3,028
Liabilities incurred	11,658
Liabilities settled	(16)
Accretion expense	232
ARO at September 30, 2015	$ 14,902

NOTE 7. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The pension and other postretirement benefit plans described below only relate to Avista Utilities. AEL&P (not discussed below) participates in a defined contribution multiemployer plan for its union workers and a defined contribution money purchase pension plan for its nonunion workers. METALfx (not discussed below) has a defined contribution 401(k) savings plan. None of the subsidiary retirement plans, individually or in the aggregate, are significant to Avista Corp.

Avista Utilities

The Company has a defined benefit pension plan covering the majority of all regular full-time employees at Avista Utilities that were hired prior to January 1, 2014. Individual benefits under this plan are based upon the employee’s years of service, date of hire and average compensation as specified in the plan. Non-union employees hired on or after January 1, 2014 participate in a defined contribution 401(k) plan in lieu of a defined benefit pension plan. 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 $12.0 million in cash to the pension plan for the nine months ended September 30, 2015 and expects to make no further contributions in 2015. The Company contributed $32.0 million in cash to the pension plan in 2014.

The Company also has a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to executive officers and certain key employees of the Company. The SERP is intended to provide benefits to individuals whose benefits under the defined benefit pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans. The liability and expense for the SERP are included as pension benefits in the tables included in this Note.

The Company provides certain health care and life insurance benefits for eligible retired employees that were hired prior to January 1, 2014. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The liability and expense of this plan are included as other postretirement benefits. Non-union employees hired on or after January 1, 2014, will have access to the retiree medical plan upon retirement; however, Avista Corp. will no longer provide a contribution toward their medical premium.

The Company has a Health Reimbursement Arrangement (HRA) to provide employees with tax-advantaged funds to pay for allowable medical expenses upon retirement. The amount earned by the employee is fixed on the retirement date based on the employee’s years of service and the ending salary. The liability and expense of the HRA are included as other postretirement benefits.

The Company provides death benefits to beneficiaries of executive officers who die during their term of office or after retirement. Under the plan, an executive officer’s designated beneficiary will receive a payment equal to twice the executive officer’s annual base salary at the time of death (or if death occurs after retirement, a payment equal to twice the executive officer’s total annual pension benefit). The liability and expense for this plan are included as other postretirement benefits.

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	
	2015	2014	2015	2014
Three months ended September 30:				
Service cost	$ 4,984	$ 3,868	$ 721	$ 499
Interest cost	6,531	6,706	1,292	1,353
Expected return on plan assets	(7,075)	(8,110)	(500)	(472)
Amortization of prior service cost	6	6	(287)	(43)
Net loss recognition	2,397	1,163	1,324	826
Net periodic benefit cost	$ 6,843	$ 3,633	$ 2,550	$ 2,163
Nine months ended September 30:				
Service cost	$ 14,917	$ 12,754	$ 2,141	$ 1,972
Interest cost	19,734	20,118	3,915	4,059
Expected return on plan assets	(21,566)	(24,330)	(1,431)	(1,416)
Amortization of prior service cost	18	18	(853)	(129)
Net loss recognition	7,425	2,334	3,879	2,001
Net periodic benefit cost	$ 20,528	$ 10,894	$ 7,651	$ 6,487

NOTE 8. COMMITTED LINES OF CREDIT

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million that expires in April 2019.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under the Company's revolving committed lines of credit were as follows as of September 30, 2015 and December 31, 2014 (dollars in thousands):

	September 30, 2015	December 31, 2014
Borrowings outstanding at end of period	$ 130,000	$ 105,000
Letters of credit outstanding at end of period	$ 43,812	$ 32,579
Average interest rate on borrowings at end of period	0.95%	0.93%

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, 2015 and December 31, 2014, there were no borrowings outstanding under this committed line of credit.

NOTE 9. LONG-TERM DEBT

The following details long-term debt outstanding as of September 30, 2015 and December 31, 2014 (dollars in thousands):

Maturity Year	Description	Interest Rate	September 30, 2015	December 31, 2014
Avista Corp. Secured Long-Term Debt				
2016	First Mortgage Bonds	0.84%	$ 90,000	$ 90,000
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
2047	First Mortgage Bonds	4.23%	80,000	80,000
	Total Avista Corp. secured long-term debt		1,436,700	1,436,700
Alaska Electric Light and Power Company Secured Long-Term Debt				
2044	First Mortgage Bonds	4.54%	75,000	75,000
	Total consolidated secured long-term debt		1,511,700	1,511,700
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		1,526,700	1,526,700
Other Long-Term Debt Components				
	Capital lease obligations		69,331	74,149
	Settled interest rate swaps (2)		(26,617)	(17,541)
	Unamortized debt discount		(998)	(1,122)
	Total other long-term debt components		41,716	55,486
	Total		1,568,416	1,582,186
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Current portion of long-term debt and capital leases		(93,105)	(6,424)
	Total long-term debt and capital leases		$ 1,391,611	$ 1,492,062

(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 bond issues (Series 2010A and Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Condensed Consolidated Balance Sheets.

(2) Upon settlement of interest rate swaps, these are recorded as a regulatory asset or liability and included as part of long-term debt above. They are amortized as a component of interest expense over the life of the associated debt and included as a part of the Company's cost of debt calculation for ratemaking purposes.

In October 2015, the Company entered into a bond purchase agreement with five institutional investors in the private placement market for the issuance and sale of $100.0 million of Avista Corp. first mortgage bonds in December 2015. The first mortgage bonds will bear an interest rate of 4.37 percent and mature in December 2045. In connection with this agreement, the Company cash-settled five interest rate swap contracts (notional aggregate amount of $75.0 million) and paid a total of $9.3 million. Upon settlement of interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the term of the associated debt.

Snettisham Capital Lease Obligation

Included in long-term capital leases above is a power purchase agreement between AEL&P and Alaska Industrial Development and Export Authority (AIDEA), an agency of the State of Alaska, under which AEL&P has a take-or-pay obligation, expiring in December 2038, to purchase all the output of the 78 MW Snettisham hydroelectric project. For accounting purposes, this power purchase agreement is treated as a capital lease.

The balances related to the Snettisham capital lease obligation as of September 30, 2015 and December 31, 2014 were as follows (dollars in thousands):

	September 30, 2015	December 31, 2014
Capital lease obligation (1)	$ 64,967	$ 69,955
Capital lease asset (2)	71,007	71,007
Accumulated amortization of capital lease asset (2)	4,552	1,821

(1) The capital lease obligation amount is equal to the amount of AIDEA's revenue bonds outstanding.
(2) These amounts are included in utility plant in service on the Condensed Consolidated Balance Sheet.

Interest on the capital lease obligation and amortization of the capital lease asset are included in utility resource costs in the Condensed Consolidated Statements of Income and totaled the following amounts for the three and nine months ended September 30 (dollars in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Interest on capital lease obligation	$ 897	$ 954	$ 2,742	$ 954
Amortization of capital lease asset	911	910	2,731	910

AIDEA issued $100.0 million of revenue bonds in 1998 to finance its acquisition of the project and the payments by AEL&P were designed to be more than sufficient to enable the AIDEA to pay the principal of and interest on its revenue bonds, which bore interest at rates ranging from 4.9 percent to 6.0 percent and were set to mature in January 2034.

In August 2015, AIDEA issued $65.7 million of new revenue bonds for the purpose of refunding all of the remaining outstanding revenue bonds for the Snettisham Hydroelectric Project. The new revenue bonds have interest rates ranging from 4.0 percent to 5.0 percent and mature in January 2034. AEL&P is scheduled to make its last bond payment to AIDEA in December 2033. The payments by AEL&P under the power purchase agreement between AEL&P and AIDEA are unconditional, notwithstanding any suspension, reduction or curtailment of the operation of the project. The bonds are payable solely out of AIDEA's receipts under the power purchase agreement. AEL&P is also obligated to operate, maintain and insure the project. The power purchase agreement did not change as a result of the refunding and the lower debt service payments that resulted from the refunding will be passed through to AEL&P. As a result of the refunding, AEL&P recognized a gain of $3.3 million, which was recorded as a regulatory liability. The benefits from the refunding will eventually be passed through to customers in future periods via lower purchased power costs, after a new general rate case is filed. AEL&P's new payments for power under the agreement are approximately $10.2 million per year, while debt service on the bonds is approximately $5.5 million per year, which is included in the $10.2 million total cost of power.

Snettisham Electric Company, a non-operating subsidiary of AERC, has the option to purchase the Snettisham project with certain conditions at any time for the principal amount of the bonds outstanding at that time.

While the power purchase agreement is treated as a capital lease for accounting purposes, for ratemaking purposes this agreement is treated as an operating lease with a constant level of annual rental expense (straight line expense). Because of this regulatory treatment, any difference between the operating lease expense for ratemaking purposes and the expenses recognized under capital lease treatment (interest and depreciation of the capital lease asset) is recorded as a regulatory asset and amortized during the later years of the lease when the capital lease expense is less than the operating lease expense included in base rates.

The Company evaluated this agreement to determine if it has a variable interest which must be consolidated. Based on this evaluation, AIDEA will not be consolidated under ASC 810 "Consolidation" because AIDEA is a government agency and ASC 810 has a specific scope exception which does not allow for the consolidation of government organizations.

The following table details future capital lease obligations, including interest, under the Snettisham power purchase agreement (dollars in thousands):

	Remaining 2015	2016	2017	2018	2019	Thereafter	Total
Principal	$ 512	$ 2,295	$ 2,415	$ 2,535	$ 2,660	$ 54,550	$ 64,967
Interest	845	3,157	3,042	2,921	2,795	21,857	34,617
Total	$ 1,357	$ 5,452	$ 5,457	$ 5,456	$ 5,455	$ 76,407	$ 99,584

NOTE 10. LONG-TERM DEBT TO AFFILIATED TRUSTS

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly. The distribution rates paid were as follows during the nine months ended September 30, 2015 and the year ended December 31, 2014:

	September 30, 2015	December 31, 2014
Low distribution rate	1.11%	1.10%
High distribution rate	1.20%	1.11%
Distribution rate at the end of the period	1.20%	1.11%

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 on or after June 1, 2007 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 as of September 30, 2015 and December 31, 2014. Interest expense to affiliated trusts in the Condensed Consolidated Statements of Income represents interest expense on these debentures.

NOTE 11. FAIR VALUE

The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable and short-term borrowings are reasonable estimates of their fair values. Long-term debt (including current portion and material capital leases), nonrecourse long-term debt 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 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, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

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

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of Avista Corp.'s nonperformance risk on its liabilities.

The following table sets forth the carrying value and estimated fair value of the Company's financial instruments not reported at estimated fair value on the Condensed Consolidated Balance Sheets as of September 30, 2015 and December 31, 2014 (dollars in thousands):

	September 30, 2015		December 31, 2014	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 951,000	$ 1,088,596	$ 951,000	$ 1,118,972
Long-term debt (Level 3)	492,000	505,343	492,000	527,663
Snettisham capital lease obligation (Level 3)	64,967	63,869	69,955	79,290
Nonrecourse long-term debt (Level 3)	—	—	1,431	1,440
Long-term debt to affiliated trusts (Level 3)	51,547	37,629	51,547	38,582

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 73.00 to 125.39, where a par value of 100.0 represents the carrying value recorded on the Consolidated Balance Sheets. Due to the unique nature of the Snettisham capital lease obligation, the estimated fair value of this item 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 Moody's Aaa Corporate discount rate as published by the Federal Reserve on September 30, 2015.

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, 2015 and December 31, 2014 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, 2015					
Assets:					
Energy commodity derivatives	$ —	$ 75,433	$ —	$ (74,534)	$ 899
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	692	(692)	—
Foreign currency derivatives	—	8	—	(8)	—
Interest rate swaps	—	1,002	—	(1,002)	—
Deferred compensation assets:					
Fixed income securities (2)	1,793	—	—	—	1,793
Equity securities (2)	5,753	—	—	—	5,753
Total	$ 7,546	$ 76,443	$ 692	$ (76,236)	$ 8,445
Liabilities:					
Energy commodity derivatives	$ —	$ 98,253	$ —	$ (87,126)	$ 11,127
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	5,435	(692)	4,743
Power exchange agreement	—	—	23,179	—	23,179
Power option agreement	—	—	117	—	117
Foreign currency derivatives	—	73	—	(8)	65
Interest rate swaps	—	88,975	—	(37,272)	51,703
Total	$ —	$ 187,301	$ 28,731	$ (125,098)	$ 90,934

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2014					
Assets:					
Energy commodity derivatives	$ —	$ 96,729	$ —	$ (95,204)	$ 1,525
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	1,349	(1,349)	—
Foreign currency derivatives	—	1	—	(1)	—
Interest rate swaps	—	966	—	(506)	460
Funds held in trust account of Spokane Energy	1,600	—	—	—	1,600
Deferred compensation assets:					
Fixed income securities (2)	1,793	—	—	—	1,793
Equity securities (2)	6,074	—	—	—	6,074
Total	$ 9,467	$ 97,696	$ 1,349	$ (97,060)	$ 11,452
Liabilities:					
Energy commodity derivatives	$ —	$ 127,094	$ —	$ (110,714)	$ 16,380
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	1,384	(1,349)	35
Power exchange agreement	—	—	23,299	—	23,299
Power option agreement	—	—	424	—	424
Interest rate swaps	—	77,568	—	(29,386)	48,182
Foreign currency derivatives	—	21	—	(1)	20
Total	$ —	$ 204,683	$ 25,107	$ (141,450)	$ 88,340

(1) The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a legally enforceable master netting agreement exists. In addition, the Company nets derivative assets and derivative liabilities against any payables and receivables for cash collateral held or placed with these same counterparties.
(2) These assets are trading securities and are included in other property and investments-net on the Condensed Consolidated Balance Sheets.

Avista Corp. enters into forward contracts to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. These contracts are entered into as part of Avista Corp.'s management of loads and resources and certain contracts are considered derivative instruments. The difference between the amount of derivative assets and liabilities disclosed in respective levels and the amount of derivative assets and liabilities disclosed on the Condensed Consolidated Balance Sheets is due to netting arrangements with certain counterparties. The Company uses quoted market prices and forward price curves to estimate the fair value of utility derivative commodity instruments included in Level 2. In particular, electric derivative valuations are performed using broker 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 broker quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

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 $0.7 million as of September 30, 2015 and $0.8 million as of December 31, 2014.

Level 3 Fair Value

For the power exchange agreement, 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 operating and maintenance (O&M) charges from four surrogate nuclear power plants around the country 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), 2) estimated delivery volumes, and 3) volatility rates for periods beyond October 2018. Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, changes in overall commodity market prices and volatility rates are accompanied by directionally similar changes in the strike price and volatility 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, 2015 (dollars in thousands):

	Fair Value (Net) at September 30, 2015	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (23,179)	Surrogate facility pricing	O&M charges	$33.52-$43.65/MWh (1)
			Escalation factor	3% - 2016 to 2019
			Transaction volumes	392,608 - 397,030 MWhs
Power option agreement	(117)	Black-Scholes-Merton	Strike price	$39.85/MWh - 2016
				$50.31/MWh - 2019
			Delivery volumes	157,517 - 286,307 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreement	(4,743)	Internally derived weighted average cost of gas	Forward purchase prices	$2.10 - $2.69/mmBTU
			Forward sales prices	$2.14 - $3.68/mmBTU
			Purchase volumes	125,000 - 310,000 mmBTUs
			Sales volumes	60,000 - 310,000 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2015 are $39.27 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 2015 are $43.52 for Washington and $39.27 for Idaho.

(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.35 for 2015 to 0.21 in October 2018.

Avista Corp.'s Risk Management team and accounting team are responsible for developing the valuation methods described above and both groups report to the Chief Financial Officer. The valuation methods, significant inputs and resulting fair values described above are reviewed on at least a quarterly basis by the risk management team and the accounting team 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, 2015:				
Balance as of July 1, 2015	$ (6,825)	$ (18,616)	$ (145)	$ (25,586)
Total gains or losses (realized/unrealized):				
Included in regulatory assets/liabilities (1)	1,800	(4,563)	28	(2,735)
Settlements	282	—	—	282
Ending balance as of September 30, 2015 (2)	$ (4,743)	$ (23,179)	$ (117)	$ (28,039)
Three months ended September 30, 2014:				
Balance as of July 1, 2014	$ (2,183)	$ (7,919)	$ (605)	$ (10,707)
Total gains or losses (realized/unrealized):				
Included in regulatory assets/liabilities (1)	712	(4,935)	243	(3,980)
Settlements	—	—	—	—
Ending balance as of September 30, 2014 (2)	$ (1,471)	$ (12,854)	$ (362)	$ (14,687)
Nine months ended September 30, 2015:				
Balance as of January 1, 2015	$ (35)	$ (23,299)	$ (424)	$ (23,758)
Total gains or losses (realized/unrealized):				
Included in regulatory assets/liabilities (1)	(5,586)	(4,393)	307	(9,672)
Settlements	878	4,513	—	5,391
Ending balance as of September 30, 2015 (2)	$ (4,743)	$ (23,179)	$ (117)	$ (28,039)
Nine months ended September 30, 2014:				
Balance as of January 1, 2014	$ (1,219)	$ (14,441)	$ (775)	$ (16,435)
Total gains or losses (realized/unrealized):				
Included in regulatory assets/liabilities (1)	2,796	2,120	413	5,329
Settlements	(3,048)	(533)	—	(3,581)
Ending balance as of September 30, 2014 (2)	$ (1,471)	$ (12,854)	$ (362)	$ (14,687)

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

NOTE 12. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORP. SHAREHOLDERS

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corp. shareholders for the three and nine months ended September 30 (in thousands, except per share amounts):

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Numerator:				
Net income from continuing operations attributable to Avista Corp. shareholders	$ 12,722	$ 10,506	$ 84,221	$ 89,236
Net income (loss) from discontinued operations attributable to Avista Corp. shareholders	289	(55)	485	70,585
Subsidiary earnings adjustment for dilutive securities (discontinued operations)	—	—	—	5
Adjusted net income (loss) from discontinued operations attributable to Avista Corp. shareholders for computation of diluted earnings per common share	$ 289	$ (55)	$ 485	$ 70,590
Denominator:				
Weighted-average number of common shares outstanding-basic	62,299	63,934	62,299	61,413
Effect of dilutive securities:				
Performance and restricted stock awards	389	310	392	212
Weighted-average number of common shares outstanding-diluted	62,688	64,244	62,691	61,625
Earnings per common share attributable to Avista Corp. shareholders, basic:				
Earnings per common share from continuing operations	$ 0.21	$ 0.16	$ 1.35	$ 1.45
Earnings per common share from discontinued operations	$ —	$ —	$ 0.01	$ 1.15
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 0.21	$ 0.16	$ 1.36	$ 2.60
Earnings per common share attributable to Avista Corp. shareholders, diluted:				
Earnings per common share from continuing operations	$ 0.21	$ 0.16	$ 1.34	$ 1.45
Earnings per common share from discontinued operations	$ —	$ —	$ 0.01	$ 1.14
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 0.21	$ 0.16	$ 1.35	$ 2.59

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

NOTE 13. 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.

Pacific Northwest Refund Proceeding

In July 2001, the Federal Energy Regulatory Commission (“FERC” or “Commission”) initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. In August 2007, the Ninth Circuit found that the FERC had failed to take into account new evidence of market manipulation and that such failure was arbitrary and capricious and, accordingly, remanded the case to the FERC, stating that the FERC's findings must be reevaluated in light of the new evidence. The Ninth Circuit expressly declined to direct the FERC to grant refunds. On October 3, 2011, the

FERC issued an Order on Remand. On April 5, 2013, the FERC issued an Order on Rehearing expanding the temporal scope of the proceeding to permit parties to submit evidence on transactions during the period from January 1, 2000 through and including June 20, 2001. The Order on Remand established an evidentiary, trial-type hearing before an ALJ, and reopened the record to permit parties to present evidence of unlawful market activity. The Order on Remand stated that parties seeking refunds must submit evidence demonstrating that specific unlawful market activity occurred, and must demonstrate that such activity directly affected negotiations with respect to the specific contract rate about which they complain. Simply alleging a general link between the dysfunctional spot market in California and the Pacific Northwest spot market would not be sufficient to establish a causal connection between a particular seller's alleged unlawful activities and the specific contract negotiations at issue. The hearing was conducted in August through October 2013.

On July 11, 2012 and March 28, 2013, Avista Energy and Avista Utilities filed settlements of all issues in this docket with regard to the claims made by the City of Tacoma and the California AG (on behalf of CERS). The FERC has approved the settlements and they are final. The remaining direct claimant against Avista Utilities and Avista Energy in this proceeding is the City of Seattle, Washington (Seattle).

With regard to the Seattle claims, on March 28, 2014, the Presiding ALJ issued her Initial Decision finding that: 1) Seattle failed to demonstrate that either Avista Utilities or Avista Energy engaged in unlawful market activity and also failed to identify any specific contracts at issue; 2) Seattle failed to demonstrate that contracts with either Avista Utilities or Avista Energy imposed an excessive burden on consumers or seriously harmed the public interest; and that 3) Seattle failed to demonstrate that either Avista Utilities or Avista Energy engaged in any specific violations of substantive provisions of the FPA or any filed tariffs or rate schedules. Accordingly, the ALJ denied all of Seattle's claims under both section 206 and section 309 of the FPA. On May 22, 2015, the FERC issued its Order on Initial Decision in which it upheld the ALJ's Initial Decision denying all of Seattle's claims against Avista Utilities and Avista Energy. Seattle has filed a Request for Rehearing of the FERC's Order on Initial Decision. The Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

Sierra Club and Montana Environmental Information Center Litigation

On March 6, 2013, the Sierra Club and Montana Environmental Information Center (MEIC) (collectively "Plaintiffs"), filed a Complaint in the United States District Court for the District of Montana, Billings Division, against the Owners of the Colstrip Generating Project ("Colstrip"). Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The other Colstrip co-Owners are Talen (formerly PPL Montana), Puget Sound Energy, Portland General Electric Company, NorthWestern Energy and PacifiCorp. The Complaint alleges certain violations of the Clean Air Act, including the New Source Review, Title V and opacity requirements.

On September 27, 2013, the Plaintiffs filed an Amended Complaint. The Amended Complaint withdrew from the original Complaint fifteen claims related to seven pre-January 1, 2001 Colstrip maintenance projects, upgrade projects and work projects and claims alleging violations of Title V and opacity requirements. The Amended Complaint alleges certain violations of the Clean Air Act and the New Source Review and adds claims with respect to post-January 1, 2001 Colstrip projects.

On August 27, 2014, the Plaintiffs filed a Second Amended Complaint. The Second Amended Complaint withdraws from the Amended Complaint five claims and adds one new claim. The Second Amended Complaint alleges certain violations of the Clean Air Act and the New Source Review. The Plaintiffs request that the Court grant injunctive and declaratory relief, order remediation of alleged environmental damages, impose civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require payment of Plaintiffs' costs of litigation and attorney fees. The Plaintiffs have since indicated that they do not intend to pursue two of the seven projects, leaving a total of five projects remaining.

The case has been bifurcated into separate liability and remedy trials. The Court has set the liability trial date for May 31, 2016. No date has been set for the remedy trial.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to uncertainties concerning this matter, Avista Corp. cannot predict the outcome or determine whether it would have a material impact on the Company.

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels (referred to as "TDG") in the Clark Fork River exceed state of Idaho and federal water quality numeric standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement 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. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

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 Clark Fork Settlement Agreement 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. Fishway designs for Cabinet Gorge are still being finalized. Construction cost estimates and schedules will be developed after several remaining issues are resolved, related to Montana's approval of fish transport from Idaho and expected minimum discharge requirements. Fishway design for Noxon Rapids has also been initiated, and is still in early stages.

The Company believes its ongoing efforts through the Clark Fork Settlement Agreement continue to effectively address issues related to bull trout. 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.

Collective Bargaining Agreements

The Company’s collective bargaining agreements with the International Brotherhood of Electrical Workers (IBEW) represent approximately 45 percent of all of Avista Utilities’ employees. The agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the Avista Utilities' bargaining unit employees expired in March 2014. A new two-year agreement with this group was approved in January 2015 and has an expiration of March 2016.

In October 2015, a new collective bargaining agreement concerning wages over the three-year period 2016 through 2018 was presented to the local IBEW in Washington and Idaho. A vote by the union on the new agreement is expected to occur during November 2015.

A new three-year agreement in Oregon, which covers approximately 50 employees, was approved in April 2014 and expires in March 2017.

A new collective bargaining agreement with the local union of the IBEW in Alaska was signed in May 2013 and expires in March 2017. The collective bargaining agreement with the IBEW in Alaska represents approximately 54 percent of all AERC employees. The remainder of AERC's employees are non-union.

There is a risk that if collective bargaining agreements expire and new agreements are not reached in each of our jurisdictions, employees could strike. Given the magnitude of employees that are covered by collective bargaining agreements, this could result in disruptions of our operations. However, the Company believes that the possibility of this occurring is remote.

Customer Information and Work Management Systems Project Cost Recovery

Over the past four years, Avista Corp. has invested significant capital into the replacement of its customer information and work management systems (Project Compass). Project Compass was completed and went into service during the first quarter of 2015. As part of the Washington electric and natural gas general rate cases filed in February 2015 and the Oregon natural gas general rate case filed in May 2015, Avista Utilities has requested the full recovery of the Washington and Oregon share of the costs associated with this project.

On July 27, 2015, the UTC Staff in the Company's electric and natural gas general rate cases filed responsive testimony. Included in their testimony was a recommendation to disallow $12.7 million (Washington's share) of Project Compass costs.

In October 2015, the OPUC staff filed testimony in the Company's natural gas general rate case which included a recommendation to disallow $1.2 million (Oregon's share) of Project Compass costs.

The recommended disallowances in Washington and Oregon are primarily related to the seven month delay in the full completion of the project. Avista Utilities has concluded that the likelihood that part of the cost of Project Compass will be disallowed for ratemaking purposes is less than probable.

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.

NOTE 14. 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 (acquired in the AERC acquisition on July 1, 2014) 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. All goodwill associated with the AERC acquisition was assigned to the AEL&P reportable business segment. The Other category, which is not a reportable segment, includes Spokane Energy, which was dissolved during the third quarter of 2015, other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital.

Ecova is a provider of facility information and cost management services for multi-site customers throughout North America. The Ecova business segment was disposed of as of June 30, 2014. All income statement amounts were reclassified to discontinued operations on the Condensed Consolidated Statements of Income for all periods presented.

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, 2015:						
Operating revenues	$ 298,132	$ 9,273	$ 307,405	$ 6,244	$ —	$ 313,649
Resource costs	135,048	3,162	138,210	—	—	138,210
Other operating expenses	71,536	2,779	74,315	6,462	—	80,777
Depreciation and amortization	34,986	1,317	36,303	178	—	36,481
Income (loss) from operations	34,800	1,508	36,308	(396)	—	35,912
Interest expense (2)	19,054	896	19,950	150	(29)	20,071
Income taxes	5,980	229	6,209	(94)	—	6,115
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	12,525	394	12,919	(197)	—	12,722
Capital expenditures (3)	92,271	2,778	95,049	348	—	95,397
For the three months ended September 30, 2014:						
Operating revenues	$ 282,555	$ 9,157	$ 291,712	$ 10,296	$ (450)	$ 301,558
Resource costs	128,591	2,997	131,588	—	—	131,588
Other operating expenses	69,403	3,106	72,509	10,701	(450)	82,760
Depreciation and amortization	32,006	1,288	33,294	154	—	33,448
Income (loss) from operations	32,048	1,273	33,321	(559)	—	32,762
Interest expense (2)	18,247	485	18,732	186	(163)	18,755
Income taxes	7,146	329	7,475	(174)	—	7,301
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	10,349	511	10,860	(354)	—	10,506
Capital expenditures (3)	92,197	1,053	93,250	194	—	93,444
For the nine months ended September 30, 2015:						
Operating revenues	$ 1,042,913	$ 32,279	$ 1,075,192	$ 22,829	$ (550)	$ 1,097,471
Resource costs	479,604	9,282	488,886	—	—	488,886
Other operating expenses	212,293	8,306	220,599	23,474	(550)	243,523
Depreciation and amortization	102,334	3,945	106,279	512	—	106,791
Income (loss) from operations	175,003	9,001	184,004	(1,157)	—	182,847
Interest expense (2)	56,991	2,695	59,686	461	(81)	60,066
Income taxes	45,500	2,504	48,004	(626)	—	47,378
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	81,387	3,953	85,340	(1,119)	—	84,221
Capital expenditures (3)	264,283	8,518	272,801	852	—	273,653

	Avista Utilities		Alaska Electric Light and Power Company		Total Utility		Other		Intersegment Eliminations (1)		Total
For the nine months ended September 30, 2014:											
Operating revenues	$	1,023,684	$	9,157	$	1,032,841	$	29,225	$	(1,350)	$	1,060,716
Resource costs		478,010		2,997		481,007		—		—		481,007
Other operating expenses		204,089		3,106		207,195		21,864		(1,350)		227,709
Depreciation and amortization		93,912		1,288		95,200		452		—		95,652
Income from operations		177,653		1,273		178,926		6,909		—		185,835
Interest expense (2)		55,215		485		55,700		899		(330)		56,269
Income taxes		48,068		329		48,397		2,877		—		51,274
Net income from continuing operations attributable to Avista Corp. shareholders		85,030		511		85,541		3,528		167		89,236
Capital expenditures (3)		228,711		1,053		229,764		296		—		230,060
Total Assets:												
As of September 30, 2015:	$	4,422,431	$	265,578	$	4,688,009	$	51,197	$	—	$	4,739,206
As of December 31, 2014:	$	4,367,926	$	264,195	$	4,632,121	$	80,210	$	—	$	4,712,331

(1) Intersegment eliminations reported as operating revenues and resource costs represent intercompany purchases and sales of electric capacity and energy. Intersegment eliminations reported as interest expense and net income (loss) attributable to Avista Corp. shareholders represent intercompany interest.

(2) Including interest expense to affiliated trusts.

(3) The capital expenditures for the other businesses are included as other capital expenditures on the Condensed Consolidated Statements of Cash Flows. The remainder of the balance included in other capital expenditures on the Condensed Consolidated Statements of Cash Flows in 2014 are related to Ecova.

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, 2015, and the related condensed consolidated statements of income and comprehensive income for the three-month and nine-month periods ending September 30, 2015 and 2014, and the related condensed consolidated statements of equity and redeemable noncontrolling interests and cash flows for the nine-month periods ended September 30, 2015 and 2014. 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, 2014, 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 25, 2015, 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, 2014 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
November 3, 2015

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

Business Segments

As of September 30, 2015, we have two reportable business segments as follows:

- **Avista Utilities** – an operating division of Avista Corp. (not a subsidiary) that comprises our regulated utility operations in the Pacific Northwest. Avista Utilities generates, transmits and distributes electricity and distributes natural gas, serving electric and natural gas customers in eastern Washington and northern Idaho and natural gas customers in parts of Oregon. We also supply electricity to a small number of customers in Montana, most of whom are employees who operate our Noxon Rapids generating facility. Avista Utilities also engages in wholesale purchases and sales of electricity and natural gas.
- **Alaska Electric Light and Power Company** – the primary operating subsidiary of AERC, which provides electric services in Juneau, Alaska. We acquired AERC on July 1, 2014, and as of that date, AERC is a wholly-owned subsidiary of Avista Corp. See "Note 3 of the Notes to Condensed Consolidated Financial Statements" for further discussion regarding this acquisition.

We have other businesses, including sheet metal fabrication, venture fund investments and real estate investments, as well as certain other operations of Avista Capital. In addition, as of July 1, 2014 we own AJT Mining, which is a wholly-owned subsidiary of AERC, and is an inactive mining company holding certain properties. These activities do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp., including AM&D, doing business as METALfx.

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,	
	2015	2014	2015	2014
Avista Utilities	$ 12,525	$ 10,349	$ 81,387	$ 85,030
Alaska Electric Light and Power Company	394	511	3,953	511
Ecova - Discontinued operations (1)	289	(55)	485	70,752
Other	(197)	(354)	(1,119)	3,528
Net income attributable to Avista Corporation shareholders	$ 13,011	$ 10,451	$ 84,706	$ 159,821

(1) The results for the nine months ended September 30, 2014 include the net gain on sale of Ecova of approximately $68.0 million.

Executive Level Summary

Overall Results

Net income attributable to Avista Corporation shareholders was $13.0 million for the three months ended September 30, 2015, an increase from $10.5 million for the three months ended September 30, 2014. Avista Utilities' earnings increased primarily due to an increase in gross margin as a result of a general rate increase in Washington. In addition, both electric and natural gas loads increased as a result of favorable weather. The increase in gross margin was partially offset by increases in other operating expenses, depreciation and amortization and taxes other than income taxes, all of which were expected. There was also a decrease in income tax expense associated with reconciling the 2014 federal income tax return to the amount included in our financial statements for 2014, which was recorded during the third quarter of 2015.

Net income attributable to Avista Corporation shareholders was $84.7 million for the nine months ended September 30, 2015, a decrease from $159.8 million for the nine months ended September 30, 2014. Results for 2014 were significantly increased by the net gain on the disposition of Ecova on June 30, 2014 of approximately $68.0 million. Avista Utilities' earnings decreased primarily due to weather that was significantly warmer than normal and warmer than the prior year in the first quarter, which reduced heating loads. The decrease in heating loads in the first quarter was partially offset by the new decoupling mechanism in Washington (implemented January 1, 2015), increased cooling loads in the summer, a general rate increase in Washington, lower net power supply costs and a decrease in the provision for earnings sharing. In addition to the fluctuation in gross margin, we experienced expected increases in other operating expenses, depreciation and amortization, and taxes other than income taxes.

Results for the nine months ended September 30, 2015 also include earnings at AEL&P for the full period, whereas 2014 results only include AEL&P for the third quarter.

Results for the nine months ended September 30, 2014 include a $9.8 million net gain at Avista Energy related to the settlement of the California power markets litigation. The net gain from the litigation settlement was partially offset by a pre-tax contribution of $6.4 million of the proceeds to the Avista Foundation, a charitable organization funded by Avista Corp. Both of these transactions are reflected in the results of the other businesses for the second quarter of 2014.

Avista Utilities

Avista Utilities is our most significant business segment. Our utility financial performance is dependent upon, among other things:

- weather conditions (temperatures, precipitation levels and wind patterns) which affect energy demand and electric generation, 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 impacts on supply and demand in the wholesale energy markets,
- regulatory decisions, allowing our utility to recover costs, including purchased power and fuel costs, on a timely basis, and to earn a reasonable return on investment,
- the price of natural gas in the wholesale market, including the effect on the price of fuel for generation, and
- the price of electricity in the wholesale market, including the effects of weather conditions, natural gas prices and other factors affecting supply and demand.

General Rate Cases

In our utility operations (both Avista Utilities and AEL&P), we regularly review the need for rate changes in each jurisdiction to improve the recovery of costs and capital investments in our generation, transmission and distribution systems. See further discussion under "Regulatory Matters."

Capital Expenditures

We are making significant capital investments in generation, transmission and distribution systems to preserve and enhance service reliability for our customers and replace aging infrastructure. The following table summarizes our actual and expected capital expenditures as of and for the nine months ended September 30, 2015 (in thousands):

	Avista Utilities	AEL&P
Actual capital expenditures (current year-to-date)		
Capital expenditures (per the Condensed Consolidated Statement of Cash Flows)	264,283	8,518
Accrual-basis capital expenditures	267,674	8,518
Expected total annual accrual-basis capital expenditures (by year)		
2015	375,000	14,000
2016	375,000	17,000
2017	400,000	13,000

These estimates of capital expenditures are subject to continuing review and adjustment (see discussion under “Capital Expenditures”).

Alaska Energy and Resources Company Acquisition

On July 1, 2014, we acquired AERC, based in Juneau, Alaska. In connection with this acquisition, we issued 4,500,014 new shares of common stock to the shareholders of AERC based on a contractual formula that resulted in a price of $32.46 per share and we made $4.8 million in cash payments. The consideration exchanged reflects a purchase price of $170.0 million, plus acquired cash, less outstanding debt and other closing adjustments.

This transaction resulted in total goodwill of $52.4 million.

The completion of this transaction makes the financial results for 2015 and 2014 incomparable since the first half of 2014 does not contain any financial results from AERC. For additional information regarding the AERC transaction, including pro forma financial comparisons, see “Note 3 of the Notes to Condensed Consolidated Financial Statements.”

Ecova Disposition

On June 30, 2014, Avista Capital completed the sale of its interest in Ecova to Cofely USA Inc., an indirect subsidiary of GDF SUEZ, a French multinational utility company. The sales price was $335.0 million in cash, less the payment of debt and other customary closing adjustments. At the closing of the transaction on June 30, 2014, Ecova became a wholly-owned subsidiary of Cofely USA Inc.

Avista Capital and Cofely USA Inc. agreed to make an election under Code Section 338(h)(10) with respect to the purchase and sale of Ecova to allocate the merger consideration among the assets of Ecova deemed to have been acquired in the merger.

The purchase price of $335.0 million, as adjusted, was divided among the security holders of Ecova, including minority shareholders, option holders and a warrant holder, pro rata based on ownership. Approximately $16.8 million (5 percent of the purchase price) was held in escrow for 15 months from the closing of the transaction to satisfy certain indemnification obligations under the merger agreement, and an additional $1.0 million was held in escrow pending resolution of adjustments to working capital. The indemnification escrow and the working capital adjustment escrow amounts above represent the full amounts to be divided among all security holders pro rata based on ownership.

As expected, no claims were made against the Escrow as of September 30, 2015 (the end of the claims period) and accordingly, all Escrow amounts were released in October 2015 and we received our full portion of the Escrow proceeds together with the remainder of the working capital adjustment escrow for a total amount of of $13.8 million. After consideration of the escrow amounts received, the sales transaction provided total cash proceeds to Avista Corp., net of debt, payment to option and minority holders, income taxes and transaction expenses, of $143.9 million, resulting in a net gain of $70.2 million. Almost all of the net gain was recognized in 2014 with some minor true-ups during 2015.

On July 1, 2014, we utilized a portion of the proceeds from the Ecova sales transaction to pay off the outstanding balance owed on our committed line of credit and we initiated a common stock share repurchase program.

The completion of this transaction makes the financial results for 2015 and 2014 incomparable since the first half of 2014 contains the financial results of Ecova (in discontinued operations) and 2015 does not have any material results from Ecova. For additional information regarding the Ecova disposition, see “Note 4 of the Notes to Condensed Consolidated Financial Statements.”

Stock Repurchase Program

Avista Corp. initiated a stock repurchase program on January 2, 2015 that expired on March 31, 2015 for the repurchase of up to 800,000 shares of the Company’s outstanding common stock. Under this program, the Company repurchased 89,400 shares at a total cost of $2.9 million and an average cost of $32.66 per share. All repurchased shares reverted to the status of authorized but unissued shares. We do not have plans to repurchase additional shares during 2015.

Liquidity and Capital Resources

Avista Corp. has a $400.0 million committed line of credit with various financial institutions that expires in April 2019. We have the option to request an extension for an additional one or two years beyond April 2019, provided (1) that no event of default has occurred and is continuing prior to the requested extension and (2) the remaining term of agreement, including the requested extension period, does not exceed five years. As of September 30, 2015, there were $130.0 million of cash borrowings and $43.8 million in letters of credit outstanding, leaving $226.2 million of available liquidity under this line of credit.

The Avista Corp. facility contains customary covenants and default provisions, including a covenant which does not permit our ratio of “consolidated total debt” to “consolidated total capitalization” to be greater than 65 percent at any time. As of September 30, 2015, we were in compliance with this covenant with a ratio of 52.5 percent.

AEL&P has a $25.0 million committed line of credit that expires in November 2019. As of September 30, 2015, there were no borrowings outstanding under this committed line of credit.

The AEL&P committed line of credit agreement contains customary covenants and default provisions including a covenant which does not permit the ratio of “consolidated total debt at AEL&P” to “consolidated total capitalization at AEL&P,” (including the impact of the Snettisham obligation) to be greater than 67.5 percent at any time. As of September 30, 2015, AEL&P was in compliance with this covenant with a ratio of 57.4 percent.

In October 2015, we entered into a bond purchase agreement with five institutional investors in the private placement market for the issuance and sale of $100.0 million of Avista Corp. first mortgage bonds in December 2015. The first mortgage bonds will bear an interest rate of 4.37 percent and mature in December 2045. In connection with this pricing, we cash-settled five interest rate swap contracts (notional aggregate amount of $75.0 million) and paid a total of $9.3 million. Upon settlement of interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the term of the associated debt.

In the nine months ended September 30, 2015, we issued $1.4 million (net of issuance costs) of common stock under the employee benefit plans. We do not expect to issue any additional shares in 2015, other than small amounts under these plans.

For 2016, we expect to issue approximately $155.0 million of long-term debt and approximately $55.0 million of common stock in order to fund capital expenditures and maintain an appropriate capital structure.

After considering the expected issuances of long-term debt and common stock during 2015 and 2016, we expect net cash flows from operating activities, together with cash available under our committed line of credit agreements, to provide adequate resources to fund capital expenditures, dividends, and other contractual commitments.

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 will 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.

Washington General Rate Cases

2014 General Rate Cases

In November 2014, the UTC approved an all-party settlement agreement related to Avista Utilities' electric and natural gas general rate cases filed in February 2014 and new rates became effective on January 1, 2015. The settlement is designed to increase annual electric base revenues by $12.3 million, or 2.5 percent, inclusive of a $5.3 million power supply update as required in the settlement agreement (explained below). The settlement is designed to increase annual natural gas base revenues by $8.5 million, or 5.6 percent.

Expiring and New Rebates and Energy Recovery Mechanism (ERM)

The parties agreed in the settlement that a credit of $8.3 million from the ERM deferral balance will be returned to electric customers to help offset the 2015 rate increase. This ERM balance represents lower net power supply costs in recent years than the costs embedded in base retail rates, which are being returned to customers in the form of a rebate. This rebate will not increase or decrease our net income. Total net deferred power costs under the ERM were a liability of $13.9 million as of September 30, 2015, compared to a liability of $14.2 million as of December 31, 2014, and these deferred power cost balances represent amounts due to customers.

In addition, our electric customers were receiving benefits from two rebates that expired at the end of 2014 and which reduced monthly energy bills by 2.8 percent during 2014. The parties agreed in the settlement that we will provide a rebate to customers of $8.6 million over an 18-month period related to our sale of renewable energy credits, which will partially replace the expiring rebates and reduce customers’ monthly bills by 1.2 percent, beginning January 1, 2015. The net effect of the expiring rebates and the new rebate resulted in an increase of approximately 1.6 percent beginning January 1, 2015. These rebates are passed through to customers and do not increase or decrease our net income.

The overall change in customer billing rates from the approved settlement agreement, including the expiring and new rebates, was 2.5 percent for electric customers and 5.6 percent for natural gas customers effective January 1, 2015.

Power Supply Cost Update and Customer Information and Work Management Systems Deferral

The settlement agreement included a provision that required Avista Utilities to update base power supply costs on November 1, 2014. This update to power supply costs was reflected in the overall electric revenue increase effective January 1, 2015, and reset the base power supply costs for the ERM calculations effective January 1, 2015. The amount of the updated power supply costs was a $5.3 million increase. The increase in costs to customers from the power supply update will be offset with the available ERM deferral balance for the calendar year 2015 and the offset will not increase or decrease our net income during 2015.

The parties also agreed that the natural gas revenue requirement associated with our investment in the Customer Information and Work Management Systems capital project (Project Compass) for 2015 will be deferred for regulatory purposes for recovery in retail rates through a future general rate case, based on the actual costs of the project at the time it goes into service. Project Compass went into service in February 2015. The net income from the future recovery of these costs and return on investment, estimated to be $2.0 million on a pre-tax basis, will be recognized in the future recovery period.

Decoupling

The parties agreed that Avista Utilities will implement electric and natural gas decoupling mechanisms for a five-year period beginning January 1, 2015. Decoupling is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. Our actual revenue, based on kilowatt hour and therm sales will vary, up or down, from the level included in a general rate case, which could be caused by changes in weather, energy conservation or the economy. Per the terms of the settlement agreement and the decoupling mechanisms included therein, generally, our electric and natural gas revenues will be adjusted each month to be based on the number of customers, rather than kilowatt hour and therm sales. The difference between revenues based on sales and revenues based on the number of customers will be deferred and either surcharged or rebated to customers beginning in the following year. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to 3 percent 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 will be made for the prior calendar year. These earnings tests will reflect actual decoupled revenues, normalized power supply costs and other normalizing adjustments.

- If we have a decoupling rebate balance for the prior year and earn in excess of a 7.32 percent rate of return (ROR), the rebate to customers would be increased by 50 percent of the earnings in excess of the 7.32 percent ROR.
- If we have a decoupling rebate balance for the prior year and earn a 7.32 percent ROR or less, only the base amount of the rebate to customers would be made.
- If we have a decoupling surcharge balance for the prior year and earn in excess of a 7.32 percent ROR, the surcharge to customers would be reduced by 50 percent of the earnings in excess of the 7.32 percent ROR (or eliminated). If 50 percent of the earnings in excess of the 7.32 percent ROR exceeds the decoupling surcharge balance, the dollar amount that exceeds the surcharge balance would create a rebate balance for customers.
- If we have a decoupling surcharge balance for the prior year and earn a 7.32 percent ROR or less, the base amount of the surcharge to customers would be made.

Capital Structure

Specific capital structure ratios and the cost of capital components were not agreed to in the settlement agreement, and the revenue increases in the settlement were not tied to the 7.32 percent ROR referenced above. The electric and natural gas revenue increases were negotiated numbers, with each party using its own set of assumptions underlying its agreement to the revenue increases. The parties agreed that the 7.32 percent ROR will be used to calculate the Allowance for Funds Used During Construction (AFUDC) and other purposes.

2015 General Rate Cases

In May 2015, Avista Corp. and multiple parties to our electric and natural gas general rate case filings reached agreement on certain issues, and a partial settlement agreement was filed with the UTC for its consideration. The general rate cases were originally filed in February 2015. The partial settlement agreement includes agreement among the parties on the cost of capital, net power supply costs and the spread of any resulting revenue increase among customer classes at the conclusion of the cases. The agreed-upon ROR on rate base is 7.29 percent, with a common equity ratio of 48.5 percent and a 9.5 percent return on equity (ROE).

The partial settlement includes adjustments to the originally-filed net power supply costs, resulting from a recent change in our power supply model, updated lower contract costs associated with a recently signed power purchase agreement from Chelan PUD, and an agreed-upon additional reduction to power supply costs. The overall decrease in net power supply costs under the settlement is $12.4 million. The parties also agreed that net power supply costs would be updated with the most current information two months prior to new retail rates going into effect from this case. On October 29, 2015, the Company filed its updated power supply adjustment, pursuant to the Partial Settlement Stipulation, that further reduced the level of power supply expense by $12.3 million. The updated net power supply costs (higher or lower) would also be used to reset the base for the ERM calculations for 2016.

The agreement on the elements in the partial settlement resulted in a reduction to our originally filed base revenue increase requests. Our original base electric revenue increase request is reduced from $33.2 million (or 6.6 percent) to $17.0 million (or 3.4 percent), and our original base natural gas revenue increase request is reduced from $12.0 million (or 7.0 percent) to $11.3 million (or 6.6 percent). Both original requests filed in February 2015 were based on a proposed ROR on rate base of 7.46 percent with a common equity ratio of 48 percent and a 9.9 percent ROE.

The remaining issues to be resolved in the case include, among other things, capital investments in infrastructure improvements, as well as the recovery of increased utility operating costs.

On July 27, 2015, the UTC Staff in our Washington electric and natural gas general rate cases filed responsive testimony. Included in their testimony was a recommendation to disallow $12.7 million (Washington's share) of Project Compass costs primarily related to the seven month delay in the full completion of the project. Avista Utilities has concluded that the likelihood that part of the cost of Project Compass will be disallowed for ratemaking purposes is less than probable and we will vigorously defend the prudence of our investment in Project Compass, and full recovery of the costs.

On September 4, 2015, we filed rebuttal testimony, incorporating the partial settlement and further reducing our requested electric and natural gas revenue increases. For electric, we reduced our requested revenue increase from $17.0 million to $3.6 million, due, in part, to updated information related to federal tax adjustments, state allocations, and the delay in the expected completion date of the Nine Mile hydroelectric generation project upgrade from late 2015 to late 2016. Further reductions resulted from our proposal to delay the start date to begin amortization of existing electric meters from 2016 to 2017, associated with our proposed Advanced Meter Infrastructure project. We also proposed deferral and normalization of certain major thermal maintenance expenses, and other miscellaneous adjustments, which, if approved by the UTC, would reduce our need for increased revenues in 2016. For natural gas, we reduced our requested revenue increase from $11.3 million to $10.3 million, mainly as a result of updated information related to federal tax adjustments and changes in net plant investment expected through 2015.

The UTC has up to 11 months from our initial filing date to review our filings and issue a decision.

Idaho General Rate Cases

2014 Rate Plan Extension

Avista Utilities did not file new general rate cases in Idaho in 2014. Instead, Avista Utilities developed an extension to the 2013 and 2014 rate plan and reached a settlement agreement with all interested parties.

In September 2014, the IPUC approved our settlement, which reflects agreement among all interested parties, for a one-year extension to our current rate plan, which was set to expire on December 31, 2014. Under the approved extension, base retail rates will remain unchanged through December 31, 2015.

The settlement will provide an estimated $3.7 million increase in pre-tax income by reducing planned expenses in 2015 for our Idaho operations, resulting from:

- the delay of the beginning of the amortization of the 2013 previously deferred operations and maintenance costs pertaining to the Colstrip and Coyote Springs 2 thermal generating facilities from 2015 to 2016, and
- deferral for later review and recovery of the majority of the costs associated with Project Compass, which was implemented in February 2015.

The settlement agreement establishes an ROE deadband between the currently authorized ROE of 9.8 percent and a 9.5 percent ROE. Under the settlement agreement, we will be allowed to use any 2014 Idaho after-the-fact earnings test deferral to support an actual earned ROE in 2015 up to 9.5 percent. For 2014, we deferred a total of $7.7 million for the 2014 after-the-fact earnings test, which includes the $1.9 million recorded in 2014 related to the 2013 earnings test. During 2015, if we earn more than the 9.8 percent ROE, 50 percent of the earnings above 9.8 percent will be shared with customers through future ratemaking. For the nine months ended September 30, 2015, we have deferred $1.2 million for 2015 amounts related to the provision for earnings sharing for Idaho customers.

As part of the settlement, we agreed not to file a general rate case in 2014, and to file no earlier than May 31, 2015 for new electric or natural gas base retail rates to become effective on or after January 1, 2016. In addition, the settlement replaced two rebates, which expired on January 1, 2015, that were reducing customers' monthly energy bills by 1.3 percent for electric and 1.7 percent for natural gas. The rebates were replaced for a one-year period, through December 31, 2015, using existing deferral balances due to customers, which will have no impact on our net income. This provision does not preclude us from filing other rate adjustments such as the PGA.

2015 General Rate Cases

In October 2015, we reached a settlement agreement with all interested parties in our electric and natural gas general rate cases, which were originally filed with the IPUC on June 1, 2015. If the settlement agreement is approved by the IPUC, new rates would take effect on January 1, 2016.

If approved, the settlement agreement is designed to increase annual electric base revenues by $1.7 million or 0.7 percent and annual natural gas base revenues by $2.5 million or 3.5 percent. The settlement is based on a rate of return on rate base of 7.42 percent with a common equity ratio of 50 percent and a 9.5 percent return on equity.

The settlement agreement also reflects the following:

- an adjustment to capital additions due to a delay in the completion, from late 2015 to late 2016, of the upgrade of our Nine Mile hydroelectric generation project, which reduced the overall revenue increase by $3.3 million,
- the continued recovery of approximately $3.2 million in costs related to the Palouse Wind Project through the PCA mechanism rather than through base rates,
- the extension of certain deferral amortizations from two years to four years, which reduced the overall revenue increase by $1.0 million,
- the discontinuation of the after-the-fact earnings test (provision for earnings sharing) that was originally agreed to as part of the settlement of our 2012 electric and natural gas general rate cases, and
- the implementation of electric and natural gas Fixed Cost Adjustment mechanisms, as discussed below.

Fixed Cost Adjustment (FCA) Mechanism

The FCA is a decoupling mechanism designed to break the link between a utility's revenues and consumers' energy usage. Our revenues, based on kilowatt-hour and therm sales, vary, up or down, from the levels included in a general rate case. This could be due to changes in conservation, weather or the economy.

Under the proposed FCA mechanism, our electric and natural gas revenues would be adjusted each month to reflect revenues based on the number of customers, rather than kilowatt-hour and therm sales. The difference between revenues based on sales and revenues based on the number of customers would result in either surcharges or rebates to customers in the following year.

The FCA is similar in effect to the Washington decoupling mechanism.

Customer Rebates

As a part of our original application, we proposed to use $5.6 million related to our 2014 Idaho electric earnings sharing to extend a $2.8 million rebate customers are currently receiving in 2015. As a part of the settlement agreement, that rebate will be extended through 2017.

As a part of our original application, we proposed to use $0.2 million related to our 2014 natural gas earnings sharing to replace a portion of a $1.2 million rebate customers are currently receiving in 2015. As a part of the settlement agreement, customers will receive that rebate in 2016.

Original Requests

The original requests were for two-year electric and natural gas rate plans with requested rate increases in 2016 and 2017.

Effective January 1, 2016, we requested an overall increase in billed electric rates of 5.2 percent (designed to increase annual electric revenues by $13.2 million) and an overall increase in billed natural gas rates of 5.8 percent (designed to increase annual natural gas revenues by $3.2 million).

Effective January 1, 2017, we requested an overall increase in billed electric rates of 5.1 percent (designed to increase annual electric revenues by $13.7 million) and an overall increase in billed natural gas rates of 2.5 percent (designed to increase annual natural gas revenues by $1.7 million).

Our original requests were based on a proposed rate of return on rate base of 7.62 percent with a common equity ratio of 50 percent and a 9.9 percent return on equity.

The parties did not come to an agreement for 2017 rates; however, the settlement agreement does not preclude us from filing additional general rate cases to address rates for 2017 and beyond.

Oregon General Rate Cases

2013 General Rate Case

In January 2014, the OPUC approved a settlement agreement in Avista Utilities' natural gas general rate case (originally filed in August 2013). As agreed to in the settlement, new rates were implemented in two phases: February 1, 2014 and November 1, 2014. Effective February 1, 2014, rates increased for Oregon natural gas customers on a billed basis by an overall 4.4 percent (designed to increase annual revenues by $3.8 million). Effective November 1, 2014, rates for Oregon natural gas customers were to increase on a billed basis by an overall 1.6 percent (designed to increase annual revenues by $1.4 million).

The billed rate increase on November 1, 2014 was dependent upon the completion of Project Compass and the actual costs incurred through September 30, 2014, and the actual costs incurred through June 30, 2014 related to the Company's Aldyl A distribution pipeline replacement program. As noted elsewhere, Project Compass was implemented in February 2015. The November 1, 2014 rate increase was reduced from $1.4 million to $0.3 million due to the delay of Project Compass.

The approved settlement agreement provided for an overall authorized rate of return of 7.47 percent, with a common equity ratio of 48 percent and a 9.65 percent return on equity.

2014 General Rate Case

In January 2015, Avista Utilities filed an all-party settlement agreement with the OPUC related to our natural gas general rate case, which was originally filed in September 2014. On February 23, 2015, the OPUC issued an order rejecting the all-party settlement agreement. The OPUC expressed concerns related to, among other things, various rate design issues.

In March 2015, Avista Utilities filed an amended all-party settlement agreement with the OPUC which addressed the OPUC's concerns regarding the initial settlement agreement. The amended settlement agreement is designed to increase base natural gas revenues by $5.3 million. Included in this base rate increase is $0.3 million in base revenues that we are already receiving from customers through a separate rate adjustment. Therefore, the net increase in base revenues is $5.0 million, or 4.9 percent on a billed basis. The parties requested that new retail rates be effective on April 16, 2015. On April 9, 2015, the OPUC issued an Order approving the amended settlement agreement as filed.

This settlement agreement provides for an overall authorized rate of return of 7.516 percent with a common equity ratio of 51 percent and a 9.5 percent return on equity.

The original request was designed to increase annual natural gas revenues by $9.1 million (or 9.3 percent on a billed basis) and it was based on a proposed rate of return of 7.77 percent with a common equity ratio of 51 percent and a 9.9 percent return on equity.

2015 General Rate Case

On May 1, 2015, we filed a natural gas general rate case with the OPUC. We have requested an overall increase in base natural gas rates of 8.0 percent (designed to increase annual natural gas revenues by $8.6 million). Our request is based on a proposed ROR on rate base of 7.72 percent with a common equity ratio of 50 percent and a 9.9 percent return on equity.

In October 2015, the OPUC staff filed testimony which included a recommendation to disallow $1.2 million (Oregon's share) of Project Compass costs primarily related to the delay in the full completion of the project. We have concluded that the likelihood that part of the cost of Project Compass will be disallowed for ratemaking purposes is less than probable and we will vigorously defend the prudence of our investment in Project Compass, and full recovery of the costs.

The OPUC has up to 10 months to review the case and make a decision.

Alaska General Rate Case

AEL&P's last electric general rate case was filed in 2010 and approved by the RCA in 2011. We evaluated the need to file an electric general rate case with the RCA and we do not expect to file an electric general rate case in 2015.

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to Avista Utilities' customers with no change in gross margin (operating revenues less resource costs) or net income. In Oregon, we absorb (cost or benefit) 10 percent of the difference between actual and projected 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 $10.7 million as of September 30, 2015 and a liability of $3.9 million as of December 31, 2014.

The following PGAs went into effect in our various jurisdictions during 2014 and 2015.

Jurisdiction	PGA Effective Date	Percentage Increase / (Decrease) in Billed Rates
Washington	November 1, 2014	1.2%
	November 1, 2015	(15.0)%
Idaho	November 1, 2014	(2.1)%
	November 1, 2015	(14.5)%
Oregon	November 1, 2014	8.3%
	November 1, 2015	(14.1)%

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. Total net deferred power costs under the ERM were a liability of $13.9 million as of September 30, 2015, compared to a liability of $14.2 million as of December 31, 2014, and these deferred power cost balances represent amounts due to customers.

The difference in net power supply costs under the ERM primarily results from changes in:

- short-term wholesale market prices and sales and purchase volumes,
- the level and availability of hydroelectric generation,
- the level and availability of thermal generation (including changes in fuel prices), and
- retail loads.

Under the ERM, Avista Utilities absorbs the cost or receives the benefit from the initial amount of power supply costs in excess of or below the level in retail rates, which is referred to as the deadband. The annual (calendar year) deadband amount is $4.0 million. We incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. We share annual power supply cost variances between $4.0 million and $10.0 million with customers. There is a 50 percent customers/50 percent Company sharing ratio when actual power supply expenses are higher (surcharge to customers) than the amount included in base retail rates within this band. There is a 75 percent customers/25 percent Company sharing ratio when actual power supply expenses are lower (rebate to customers) than the amount included in base retail rates within this band. To the extent that the annual power supply cost variance from the amount included in base rates exceeds $10.0 million, there is a 90 percent customers/10 percent Company sharing ratio of the cost variance for the amount over $10.0 million.

The following is a summary of the ERM:

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
within +/- $0 to $4 million (deadband)	0%	100%
higher by $4 million to $10 million	50%	50%
lower by $4 million to $10 million	75%	25%
higher or lower by over $10 million	90%	10%

Under the ERM, Avista Utilities makes an annual filing on or before April 1 of each year to provide the opportunity for the UTC staff and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. We made our annual filing on March 31, 2015. The ERM provides for a 90-day review period for the filing; however, the period may be extended by agreement of the parties or by UTC order. The 2014 ERM deferred power cost transactions were approved by an order from the UTC.

Avista Utilities has a PCA mechanism in Idaho that allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. The October 1 rate adjustments recover or rebate power supply costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were an asset of $1.4 million as of September 30, 2015 compared to an asset of $8.3 million as of December 31, 2014.

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.

As discussed in "Item 2. Management's Discussion and Analysis: Executive Level Summary," Ecova was disposed of as of June 30, 2014. As a result, in accordance with GAAP, all of Ecova's operating results were removed from each line item on the Condensed Consolidated Statements of Income and reclassified into discontinued operations for all periods presented. Net income from discontinued operations attributable to Avista Corp. shareholders was $0.5 million for the nine months ended September 30, 2015 compared to $70.6 million for the nine months ended September 30, 2014. Discontinued operations for 2014 were significantly increased by the net gain on the disposition of Ecova on June 30, 2014 of approximately $68.0 million. The discussion of continuing operations below does not include any Ecova amounts.

The balances included below for utility operations reconcile to the Condensed Consolidated Statements of Income. Beginning on July 1, 2014, AEL&P is included in the overall utility results.

Three months ended September 30, 2015 compared to the three months ended September 30, 2014

Utility revenues increased $16.1 million, after elimination of intracompany revenues of $33.8 million for the third quarter of 2015 and $40.9 million for the third quarter of 2014. Avista Utilities' portion of utility revenues increased $16.0 million for the third quarter of 2015 and AEL&P electric revenues increased $0.1 million. Including intracompany revenues, Avista Utilities' electric revenues increased $7.0 million and natural gas revenues increased $1.5 million. Avista Utilities' retail electric revenues increased $8.6 million primarily due to the Washington general rate increase and partially due to an increase in loads. The decoupling mechanism in Washington reduced electric revenues by $2.2 million. Wholesale electric revenues decreased $12.3 million due to a decrease in sales volumes, partially offset by an increase in prices, while revenues from sales of fuel increased $12.3 million. In the third quarter of 2015, we recorded a provision for earnings sharing of $0.9 million for Washington electric customers and $1.2 million for Idaho electric customers. In the third quarter of 2014, we recorded a provision for earnings sharing of $3.1 million for Idaho electric customers. Retail natural gas revenues increased $2.3 million due to higher rates (from PGAs and general rate increases) and an increase in volumes. The decoupling mechanism in Washington increased natural gas revenues by $0.5 million. Wholesale natural gas revenues decreased $2.0 million due to a decrease in prices, partially offset by an increase in volumes.

Other non-utility revenues decreased $4.1 million due to the long-term fixed rate electric capacity contract that was previously held by Spokane Energy being transferred to Avista Corp. during the second quarter of 2015. The capacity revenue from this contract was included in non-utility revenues when it was held by Spokane Energy.

Utility resource costs increased $6.6 million, after elimination of intracompany resource costs of $33.8 million for the third quarter of 2015 and $40.9 million for third quarter of 2014. Avista Utilities' portion of resource costs increased $6.4 million and AEL&P electric resource costs increased $0.2 million. Including intracompany resource costs, Avista Utilities' electric resource costs increased $0.8 million and natural gas resource costs decreased $1.4 million. The increase in Avista Utilities' electric resource costs was primarily due to an increase in other fuel costs (fuel and the related derivative instruments that were purchased for generation but were later sold when conditions indicated that it was not economical to use the fuel for generation), partially offset by a decrease in purchased power costs and fuel costs. The decrease in natural gas resource costs was primarily due to a decrease in natural gas prices, partially offset by an increase in purchased volumes.

Utility other operating expenses increased $1.8 million. Avista Utilities' other operating expenses increased due to an increase in pension and other postretirement benefits, administrative and general wages and generation operating costs. These were partially offset by decreased generation maintenance and outside services expenses. Additionally, during the third quarter of 2014, there were transaction fees of $0.6 million associated with the AERC acquisition.

Utility depreciation and amortization increased $3.0 million, driven by additions to utility plant.

Utility taxes other than income taxes increased $1.3 million primarily due to increased municipal and utility property taxes.

Other non-utility operating expenses decreased $3.8 million due to the long-term fixed rate electric capacity contract that was previously held by Spokane Energy being transferred to Avista Corp. during the second quarter of 2015. The amortization of this contract was included in non-utility operating expenses when it was held by Spokane Energy.

Interest expense increased $1.3 million because there was more long-term debt outstanding during the third quarter of 2015 compared to the third quarter of 2014.

Other income-net decreased $0.5 million primarily due to a decrease in equity-related AFUDC with lower construction work in progress balances, as well as net losses on investments in 2015.

Income taxes decreased $1.2 million and our effective tax rate was 32.4 percent for the third quarter of 2015 compared to 41.0 percent for the third quarter of 2014. The decrease in tax expense and the effective tax rate was associated with reconciling the 2014 federal income tax return to the amount included in the financial statements for 2014, which was recorded during the third quarter of 2015.

Nine months ended September 30, 2015 compared to the nine months ended September 30, 2014

Utility revenues increased $43.1 million, after elimination of intracompany revenues of $78.2 million for the nine months ended September 30, 2015 and $104.2 million for the nine months ended September 30, 2014. Avista Utilities' portion of utility revenues increased $20.0 million for the nine months ended September 30, 2015 and AEL&P had electric revenues of $32.3 million. Results for 2014 only include AEL&P's third quarter revenue of $9.2 million. Including intracompany revenues, Avista Utilities' electric revenues increased $4.0 million and natural gas revenues decreased $10.8 million. Avista Utilities' retail electric revenues increased $8.3 million primarily due to the Washington general rate increase and increased cooling loads during the summer, partially offset by warmer weather (and reduced loads) in the first quarter. Wholesale electric revenues decreased $15.1 million primarily due to a decrease in sales volumes, partially offset by an increase in sales prices, while sales of fuel increased $8.3 million. In the first nine months of 2015, we recorded a provision for earnings sharing of $1.5 million for Washington electric customers and $1.2 million for Idaho electric customers. In the first nine months of 2014, we estimated a provision for earnings sharing of $6.2 million for Idaho electric customers with $4.3 million representing our estimate for the first nine months of 2014 and $1.9 million representing an adjustment of our 2013 estimate. Retail natural gas revenues decreased $11.7 million due to a decrease in volumes caused by warmer weather during 2015, partially offset by higher rates (from PGAs and general rate increases) and the decoupling deferral of $5.4 million. Wholesale natural gas revenues decreased $4.3 million due to a decrease in prices, partially offset by an increase in volumes.

Other non-utility revenues decreased $6.4 million due to the long-term fixed rate electric capacity contract that was previously held by Spokane Energy being transferred to Avista Corp. during the second quarter of 2015. The capacity revenue from this contract was included in non-utility revenues when it was held by Spokane Energy.

Utility resource costs increased $7.9 million, after elimination of intracompany resource costs of $78.2 million for the nine months ended September 30, 2015 and $104.2 million for the nine months ended September 30, 2014. Avista Utilities' portion of resource costs increased $1.6 million and AEL&P had electric resource costs of $9.3 million. Results for 2014 only include AEL&P's third quarter resource costs of $3.0 million. Including intracompany resource costs, Avista Utilities' electric resource costs decreased $10.0 million and natural gas resource costs decreased $14.4 million. The decrease in Avista Utilities' electric resource costs was primarily due to a decrease in purchased power, partially offset by an increase in power cost deferrals, as net power supply costs were below the amount included in base rates. The decrease in natural gas resource costs was primarily due to a decrease in natural gas purchased, partially offset by an increase in natural gas cost deferrals.

Utility other operating expenses increased $13.4 million. Avista Utilities' portion of other operating expenses increased $8.2 million and AEL&P had other operating expenses of $8.3 million. Results for 2014 only include AEL&P's third quarter other operating expenses of $3.1 million. Avista Utilities' other operating expenses increased due to an increase in pension and other postretirement benefits, administrative and general wages and generation and distribution operating costs. These increases were partially offset by decreased generation maintenance and outside services expenses. Additionally, during the first nine months of 2014, there were transaction fees of $1.3 million associated with the AERC acquisition.

Utility depreciation and amortization increased $11.1 million, driven by additions to utility plant as well as the inclusion of AEL&P. The nine months ended September 30, 2015 included $3.9 million related to AEL&P, whereas 2014 only included $1.3 million.

Utility taxes other than income taxes increased $4.9 million primarily due to increased utility property taxes. Also, the nine months ended September 30, 2015 included $1.7 million related to AEL&P, whereas 2014 only included $0.5 million.

Other non-utility operating expenses increased $2.4 million primarily due to receipt of $15.0 million related to the settlement of the California power markets litigation, partially offset by a $6.4 million contribution to the Avista Foundation in the second quarter of 2014. This increase was partially offset by the long-term fixed rate electric capacity contract that was previously held by Spokane Energy being transferred to Avista Corp. during the second quarter of 2015. The amortization of this contract was included in non-utility operating expenses when it was held by Spokane Energy.

Interest expense increased $3.8 million primarily due to the acquisition of AEL&P. The nine months ended September 30, 2015 included $2.7 million related to AEL&P, whereas 2014 only included $0.5 million. Also, there was more long-term debt outstanding during the first nine months of 2015 compared to the first nine months of 2014.

Other income-net decreased $2.1 million primarily due to a decrease in equity-related AFUDC with lower construction work in progress balances, as well as net losses on investments in 2015.

Income taxes decreased $3.9 million and our effective tax rate was 36.0 percent for the first nine months of 2015 compared to 36.5 percent for the first nine months of 2014. The decrease in expense was primarily due to a decrease in income before income taxes. The decrease in the effective tax rate was associated with reconciling the 2014 federal income tax return to the amount included in the financial statements for 2014, which was recorded during the third quarter of 2015.

Results of Operations - Avista Utilities

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. 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 for Avista Utilities and electric gross margin for AEL&P is intended to supplement an understanding of Avista Utilities' and AEL&P's operating performance. We use these measures to determine whether the appropriate amount of energy costs are being collected from our customers to allow for recovery of 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. 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.

Three months ended September 30, 2015 compared to the three months ended September 30, 2014

Net income for Avista Utilities was $12.5 million for the third quarter of 2015, an increase from $10.3 million for the third quarter of 2014. Avista Utilities’ income from operations was $34.8 million for the third quarter of 2015, an increase from $32.0 million for the third quarter of 2014. The increase in income from operations was primarily due to an increase in gross margin, partially offset by expected increases in other operating expenses, depreciation and amortization, and taxes other than income taxes.

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

	Electric		Natural Gas		Intracompany		Total	
	2015	2014	2015	2014	2015	2014	2015	2014
Operating revenues	$ 239,836	$ 232,819	$ 92,109	$ 90,604	$ (33,813)	$ (40,868)	$ 298,132	$ 282,555
Resource costs	97,771	97,000	71,090	72,459	(33,813)	(40,868)	135,048	128,591
Gross margin	$ 142,065	$ 135,819	$ 21,019	$ 18,145	$ —	$ —	$ 163,084	$ 153,964

Avista Utilities’ operating revenues increased $15.6 million and resource costs increased $6.5 million, which resulted in an increase of $9.1 million in gross margin. The gross margin on electric sales increased $6.2 million and the gross margin on natural gas sales increased $2.9 million. The increase in electric gross margin was primarily due to a general rate increase in Washington, slightly higher loads and a $1.0 million decrease in the provision for earnings sharing. The decoupling mechanism in Washington had a negative effect on electric revenues and gross margin of $2.2 million. In the third quarter of 2015, we recorded a provision for earnings sharing of $0.9 million for electric operations in Washington and $1.2 million for electric operations in Idaho. The provision for earnings sharing of $3.1 million for electric operations in the third quarter of 2014 was related to our Idaho operations. For the third quarter of 2015, we had a $0.1 million pre-tax expense under the ERM in Washington compared to a benefit of $0.4 million for the third quarter of 2014. The increase in natural gas gross margin was primarily due to general rate increases, a $0.9 million decrease in the provision for earnings sharing, and partially due to higher heating loads in September. The decoupling mechanism in Washington had a positive effect on natural gas revenues and gross margin of $0.5 million.

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.

The following table presents our utility electric operating revenues and megawatt-hour (MWh) sales for the three months ended September 30 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2015	2014	2015	2014
Residential	$ 78,059	$ 73,940	831	808
Commercial	81,296	78,323	847	841
Industrial	30,366	28,852	487	485
Public street and highway lighting	1,911	1,877	7	6
Total retail	191,632	182,992	2,172	2,140
Wholesale	22,919	35,209	401	915
Sales of fuel	22,900	10,647	—	—
Other	6,699	7,051	—	—
Decoupling	(2,214)	—	—	—
Provision for earnings sharing	(2,100)	(3,080)	—	—
Total	$ 239,836	$ 232,819	2,573	3,055

Retail electric revenues increased $8.6 million due to an increase in total MWhs sold (increased revenues $2.8 million) and an increase in revenue per MWh (increased revenues $5.8 million). The increase in revenue per MWh was primarily due to a general rate increase in Washington.

The increase in total retail MWhs sold was the result of weather that was significantly warmer than normal in July and August and slightly cooler than normal in September, as well as customer growth. Compared to the third quarter of 2014, residential electric use per customer increased 2 percent.

Wholesale electric revenues decreased $12.3 million due to a decrease in sales volumes (decreased revenues $29.3 million), partially offset by an increase in sales prices (increased revenues $17.0 million). The fluctuation in volumes and prices was the result of our optimization activities during the quarter, as well as a decrease in hydroelectric generation due to lower streamflows.

When current and forward electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the related natural gas purchased for generation in the wholesale market rather than operate the generating units. The revenues from sales of fuel increased $12.3 million due to an increase in sales of natural gas fuel as part of thermal generation resource optimization activities. These thermal optimization transactions also include forward hedges using derivative instruments for electricity and natural gas. As relative power and natural gas prices vary, our volume of thermal optimization also varies.

Differences between revenues and costs from wholesale sales and sales of fuel are applied to reduce or increase resource costs as accounted for under the ERM, the PCA mechanism, and in general rate cases as part of base power supply costs.

Effective January 1, 2015, we implemented electric and natural gas decoupling mechanisms in Washington. Due primarily to significantly warmer than normal weather during the third quarter of 2015 (and the resulting higher sales of electricity for cooling), we recorded a decoupling reduction to electric revenue of $2.2 million.

In Washington and Idaho, we have earnings sharing mechanisms with our customers, such that if Avista Utilities earns more than certain threshold amounts, we will share with customers 50 percent of any earnings above the threshold amounts. The Idaho earnings sharing mechanism has been in place since 2013 and is based on a 9.8 percent return on equity for consolidated Idaho electric and natural gas operations. The Washington earnings sharing mechanism was implemented in 2015 and is based on a 7.32 percent overall rate of return and is measured separately for Washington electric operations and natural gas operations. The decoupling rebate or surcharge balance also factors into the Washington earnings sharing mechanism.

In the third quarter of 2015, our electric earnings were above the threshold amount in Washington and Idaho and we recorded a provision for earnings sharing of $0.9 million for our Washington electric operations and $1.2 million for our Idaho electric operations. In the third quarter of 2014, we recorded a provision for earnings sharing to Idaho electric customers of $3.1 million.

The following table presents our utility natural gas operating revenues and therms delivered for the three months ended September 30 (dollars and therms in thousands):

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2015	2014	2015	2014
Residential	$ 19,739	$ 18,138	13,167	12,619
Commercial	11,275	10,640	11,471	11,173
Interruptible	724	567	1,165	1,066
Industrial	713	827	920	1,134
Total retail	32,451	30,172	26,723	25,992
Wholesale	56,046	58,052	218,535	151,663
Transportation	1,793	1,663	35,984	34,078
Other	1,310	1,631	20	22
Decoupling	509	—	—	—
Provision for earnings sharing	—	(914)	—	—
Total	$ 92,109	$ 90,604	281,262	211,755

Retail natural gas revenues increased $2.3 million due to higher retail rates (increased revenues $1.4 million) and an increase in volumes (increased revenues $0.9 million). Higher retail rates were due to PGAs and general rate cases. We sold more retail natural gas in the third quarter of 2015 as compared to the third quarter of 2014 due to cooler weather in September. Compared to the third quarter of 2014, residential natural gas use per customer increased 3 percent and commercial use per customer increased 2 percent.

Wholesale natural gas revenues decreased $2.0 million due to a decrease in prices (decreased revenues $19.2 million), partially offset by an increase in volumes (increased revenues $17.2 million). We plan for sufficient natural gas capacity to serve our retail customers on a theoretical peak day. As such, on nonpeak days we generally have more pipeline and storage capacity than what is needed for retail loads. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that partially offsets net natural gas costs. In some situations, customer demand is below the amount hedged and we sell natural gas in excess of load requirements. In the third quarter of 2015, $19.0 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 2014, $25.8 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.

Effective January 1, 2015, we implemented electric and natural gas decoupling mechanisms in Washington. During the third quarter of 2015, we recorded a decoupling increase to natural gas revenue of $0.5 million.

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	
	2015	2014	2015	2014
Residential	326,692	323,789	295,286	290,932
Commercial	41,176	41,084	34,110	33,931
Interruptible	—	—	36	38
Industrial	1,360	1,383	262	269
Public street and highway lighting	510	531	—	—
Total retail customers	369,738	366,787	329,694	325,170

The following table presents our utility resource costs for the three months ended September 30 (dollars in thousands):

	2015	2014
Electric resource costs:		
Power purchased	$ 38,929	$ 40,341
Power cost amortizations, net	(3,723)	(3,333)
Fuel for generation	34,377	35,651
Other fuel costs	18,677	13,800
Other regulatory amortizations, net	4,720	5,475
Other electric resource costs	4,791	5,066
Total electric resource costs	97,771	97,000
Natural gas resource costs:		
Natural gas purchased	68,194	76,183
Natural gas cost amortizations, net	2,423	(4,225)
Other regulatory amortizations, net	473	501
Total natural gas resource costs	71,090	72,459
Intracompany resource costs	(33,813)	(40,868)
Total resource costs	$ 135,048	$ 128,591

Purchased power costs decreased $1.4 million due to a decrease in the volume of power purchases (decreased costs $4.3 million), partially offset by an increase in wholesale prices (increased costs $2.9 million). The fluctuation in volumes and prices was primarily the result of our overall optimization activities during the quarter. The decrease in volumes purchased was also due to decreased availability of hydroelectric resources in the region due to lower precipitation levels.

Power cost deferrals and amortizations (net) decreased electric resource costs by $3.7 million for the three months ended September 30, 2015 compared to a decrease of $3.3 million for the three months ended September 30, 2014. During the three months ended September 30, 2015, we surcharged customers $1.9 million of previously deferred power costs in Idaho through the PCA. We also refunded to Washington customers $2.1 million through an ERM rebate and $1.5 million through a REC rebate. During the three months ended September 30, 2015, actual power supply costs were above the amount included in base retail rates and we deferred $0.4 million in Washington (which reduced the probable future benefit for customers). We also deferred $0.4 million for RECs in Washington for probable future benefit to customers. We deferred $2.1 million of power costs in Idaho for probable future surcharge, as actual power supply costs were above the amount included in base retail rates.

Fuel for generation decreased $1.3 million primarily due to a decrease in natural gas fuel prices, partially offset by an increase in thermal generation (due in part to decreased hydroelectric generation).

Other fuel costs increased $4.9 million. This represents fuel and the related derivative instruments that were purchased for generation but were later sold when conditions indicated that it was not economical to use the fuel for generation, as part of the resource optimization process. When the fuel or related derivative instruments are sold, that revenue is included in sales of fuel.

The expense for natural gas purchased decreased $8.0 million due to a decrease in the price of natural gas (decreased costs $26.8 million), partially offset by an increase in total therms purchased (increased costs $18.8 million). Total therms purchased increased due to an increase in wholesale sales which are used to balance loads and resources as part of the natural gas procurement and resource optimization process, partially offset by a decrease in retail sales. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs.

Nine months ended September 30, 2015 compared to the nine months ended September 30, 2014

Net income for Avista Utilities was $81.4 million for the first nine months of 2015, a decrease from $85.0 million for the first nine months of 2014. Avista Utilities' income from operations was $175.0 million for the first nine months of 2015, a decrease from $177.7 million for the first nine months of 2014. The decrease in income from operations was primarily due to significantly warmer weather in the first quarter. General rate increases were offset by expected increases in other operating expenses, depreciation and amortization, and taxes other than income taxes.

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	
	2015	2014	2015	2014	2015	2014	2015	2014
Operating revenues	$ 742,984	$ 738,943	$ 378,094	$ 388,904	$ (78,165)	$ (104,163)	$ 1,042,913	$ 1,023,684
Resource costs	292,942	302,900	264,827	279,273	(78,165)	(104,163)	479,604	478,010
Gross margin	$ 450,042	$ 436,043	$ 113,267	$ 109,631	$ —	$ —	$ 563,309	$ 545,674

Avista Utilities' operating revenues increased $19.2 million and resource costs increased $1.6 million, which resulted in an increase of $17.6 million in gross margin. The gross margin on electric sales increased $14.0 million and the gross margin on natural gas sales increased $3.6 million. The increase in electric gross margin was primarily due to a general rate increase in Washington, lower net power supply costs and a $3.5 million decrease in the provision for earnings sharing. We experienced weather that was significantly warmer than normal and the prior year, which decreased heating loads in the first quarter and increased cooling loads in the second quarter. Loads in the third quarter were slightly higher than the prior year. The decoupling mechanism in Washington had a negative effect on electric revenues and gross margin of $0.4 million. For the nine months ended September 30, 2015, we recorded a provision for earnings sharing of $1.5 million for electric operations in Washington and $1.2 million for electric operations in Idaho. The $6.2 million provision for earnings sharing for the nine months ended September 30, 2014 was all related to our Idaho operations. For the nine months ended September 30, 2015, we recognized a pre-tax benefit of $5.6 million under the ERM in Washington compared to a benefit of $5.3 million for the nine months ended September 30, 2014. This change represents a decrease in net power supply costs primarily due to lower natural gas fuel and purchased power prices in 2015, partially offset by lower hydroelectric generation (due to warm and dry conditions in the second and third quarters).

The increase in natural gas gross margin was primarily due to a decrease in natural gas resources costs and a $1.1 million decrease in the provision for earnings sharing, partially offset by a decrease in natural gas revenues. The decrease in natural gas revenues resulted from lower heating loads from significantly warmer weather that was partially offset by general rate increases. The earnings impact of the decrease in heating loads was partially offset by the decoupling mechanism in Washington, which had a positive effect on natural gas revenues and gross margin of $5.4 million.

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 reflected in the presentation of the separate results for electric and natural gas below.

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

	Electric Operating Revenues		Electric Energy MWh sales	
	2015	2014	2015	2014
Residential	$ 244,463	$ 247,684	2,604	2,701
Commercial	232,202	224,049	2,402	2,393
Industrial	85,921	82,279	1,384	1,392
Public street and highway lighting	5,393	5,660	18	19
Total retail	567,979	559,672	6,408	6,505
Wholesale	93,003	108,096	2,507	3,015
Sales of fuel	65,130	56,826	—	—
Other	19,914	20,533	—	—
Decoupling	(382)	—	—	—
Provision for earnings sharing	(2,660)	(6,184)	—	—
Total	$ 742,984	$ 738,943	8,915	9,520

Retail electric revenues increased $8.3 million due to an increase in revenue per MWh (increased revenues $16.9 million), partially offset by a decrease in total MWhs sold (decreased revenues $8.6 million). The increase in revenue per MWh was primarily due to a general rate increase in Washington.

The decrease in total MWhs sold was primarily the result of weather that was significantly warmer than normal and warmer than the prior year, which decreased the electric heating load in the first quarter. Compared to the nine months ended September 30, 2014, residential electric use per customer decreased 5 percent and commercial use per customer decreased 2 percent. Heating degree days at Spokane were 16 percent below normal and 16 percent below the first nine months of 2014. The impact from reduced heating loads was partially offset by increased cooling loads in the second quarter. Loads and use per customer increased slightly in the third quarter as compared to the prior year. Year-to-date cooling degree days were 141 percent above normal and 28 percent above the prior year.

Wholesale electric revenues decreased $15.1 million due to a decrease in sales volumes (decreased revenues $18.8 million), partially offset by an increase in sales prices (increased revenues $3.7 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.

When current and forward electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the related natural gas purchased for generation in the wholesale market rather than operate the generating units. The revenues from sales of fuel increased $8.3 million due to an increase in sales of natural gas fuel as part of thermal generation resource optimization activities. These thermal optimization transactions also include forward hedges using derivative instruments for electricity and natural gas. As relative power and natural gas prices vary, our volume of thermal optimization also varies. For the nine months ended September 30, 2015, $38.5 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For the nine months ended September 30, 2014, $45.9 million of these sales were made to our natural gas operations.

Differences between revenues and costs from wholesale sales and sales of fuel are applied to reduce or increase resource costs as accounted for under the ERM, the PCA mechanism, and in general rate cases as part of base power supply costs.

Effective January 1, 2015, we implemented electric and natural gas decoupling mechanisms in Washington. During the first nine months of 2015 (which reflected decreased heating loads in the first quarter and increased cooling loads in the second and third quarters), we recorded a net electric decoupling decrease to revenue of $0.4 million.

In Washington and Idaho, we have earnings sharing mechanisms with our customers, such that if Avista Utilities earns more than certain threshold amounts, we will share with customers 50 percent of any earnings above the threshold amounts. The Idaho earnings sharing mechanism has been in place since 2013 and is based on a 9.8 percent return on equity for consolidated Idaho electric and natural gas operations. The Washington earnings sharing mechanism was implemented in 2015 and is based on a 7.32 percent overall rate of return and is measured separately for Washington electric operations and natural gas operations. The decoupling rebate or surcharge balance also factors into the Washington earnings sharing mechanism.

In the first nine months of 2015, our electric earnings were above these threshold amounts in Washington and Idaho and we recorded a provision for earnings sharing of $1.5 million for our Washington electric operations and $1.2 million for our Idaho electric operations. In the first nine months of 2014, we recorded a provision for earnings sharing of $6.2 million for Idaho electric customers with $4.3 million representing our estimate for the first nine months of 2014 and $1.9 million representing an adjustment of our 2013 estimate.

The following table presents our utility natural gas operating revenues and therms delivered for the nine months ended September 30 (dollars and therms in thousands):

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2015	2014	2015	2014
Residential	$ 128,252	$ 135,954	108,929	125,329
Commercial	66,070	70,136	69,642	78,936
Interruptible	2,272	1,997	3,650	3,648
Industrial	2,877	3,071	3,702	4,125
Total retail	199,471	211,158	185,923	212,038
Wholesale	163,167	167,471	630,641	387,772
Transportation	5,843	5,658	119,323	118,726
Other	4,200	5,670	244	315
Decoupling	5,413	—	—	—
Provision for earnings sharing	—	(1,053)	—	—
Total	$ 378,094	$ 388,904	936,131	718,851

Retail natural gas revenues decreased $11.7 million due to a decrease in volumes (decreased revenues $28.0 million), partially offset by higher retail rates (increased revenues $16.3 million). Higher retail rates were due to PGAs and general rate cases. We sold less retail natural gas in the first nine months of 2015 as compared to the first nine months of 2014 due to warmer weather. Compared to the first nine months of 2014, residential natural gas use per customer decreased 15 percent and commercial use per customer decreased 13 percent. Heating degree days at Spokane were 16 percent below historical average for the nine months ended September 30, 2015, and 16 percent below the nine months ended September 30, 2014. Heating degree days at Medford were 17 percent below historical average for the first nine months of 2015 and 3 percent below the first nine months of 2014.

Wholesale natural gas revenues decreased $4.3 million due to a decrease in prices (decreased revenues $67.1 million), partially offset by an increase in volumes (increased revenues $62.8 million). We plan for sufficient natural gas capacity to serve our retail customers on a theoretical peak day. As such, on nonpeak days we generally have more pipeline and storage capacity than what is needed for retail loads. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that partially offsets net natural gas costs. In some situations, customer demand is below the amount hedged and we sell natural gas in excess of load requirements. In the first nine months of 2015, $39.6 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In the first nine months of 2014, $58.2 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.

Effective January 1, 2015, we implemented electric and natural gas decoupling mechanisms in Washington. Due primarily to significantly warmer than normal weather and the impact on heating loads during the nine months ended September 30, 2015, we recorded a natural gas decoupling increase to revenue of $5.4 million. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to 3 percent on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. Because of this 3 percent limitation, there is the potential that some decoupling revenues will not be collected from customers within 24 months of the end of the annual accrual period in which they are generated. Under GAAP, any decoupling revenue amounts that will not be collected within 24 months of the annual accrual period are not allowed to be recognized as revenue until they are billed to customers. As a result, we estimate that the maximum amount of natural gas decoupling revenue that we can recognize during 2015 is $6.8 million.

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

	Electric Customers		Natural Gas Customers	
	2015	2014	2015	2014
Residential	326,318	323,540	295,275	291,366
Commercial	41,239	40,930	34,177	34,031
Interruptible	—	—	35	37
Industrial	1,356	1,388	262	263
Public street and highway lighting	527	532	—	—
Total retail customers	369,440	366,390	329,749	325,697

The following table presents our utility resource costs for the nine months ended September 30 (dollars in thousands):

	2015	2014
Electric resource costs:		
Power purchased	$ 124,174	$ 139,144
Power cost amortizations, net	3,267	(6,217)
Fuel for generation	86,598	83,602
Other fuel costs	55,735	54,723
Other regulatory amortizations, net	14,487	16,185
Other electric resource costs	8,681	15,463
Total electric resource costs	292,942	302,900
Natural gas resource costs:		
Natural gas purchased	254,606	286,315
Natural gas cost amortizations, net	6,599	(11,373)
Other regulatory amortizations, net	3,622	4,331
Total natural gas resource costs	264,827	279,273
Intracompany resource costs	(78,165)	(104,163)
Total resource costs	$ 479,604	$ 478,010

Power purchased decreased $15.0 million due to a decrease in the volume of power purchases (decreased costs $19.1 million), partially offset by an increase in wholesale prices (increased costs $4.1 million). The fluctuation in volumes and prices was primarily the result of our overall optimization activities during the first half of 2015. The decrease in volumes purchased was also due to decreased availability of hydroelectric resources in the region due to lower precipitation levels, as well as a decrease in retail loads in the first quarter.

Power cost deferrals and amortizations (net) increased electric resource costs by $3.3 million for the nine months ended September 30, 2015 compared to a decrease of $6.2 million for the nine months ended September 30, 2014. During the nine months ended September 30, 2015, we surcharged customers $5.8 million of previously deferred power costs in Idaho through the PCA. We also refunded to Washington customers $6.2 million through an ERM rebate and $4.0 million through a REC rebate. During the nine months ended September 30, 2015, actual power supply costs were below the amount included in base retail rates and we deferred $6.9 million in Washington (including $1.4 million for RECs in Washington for probable future benefit to customers) and $0.8 million in Idaho for probable future benefit to customers.

Fuel for generation increased $3.0 million primarily due to an increase in thermal generation (due in part to decreased hydroelectric generation and a decrease in total MWhs sold), partially offset by a decrease in natural gas fuel prices.

Other fuel costs increased $1.0 million. This represents fuel and the related derivative instruments that were purchased for generation but were later sold when conditions indicated that it was not economical to use the fuel for generation, as part of the resource optimization process. When the fuel or related derivative instruments are sold, that revenue is included in sales of fuel.

Other electric resource costs decreased $6.8 million primarily due to the benefit from a capacity contract of Spokane Energy, which was mostly deferred for probable future benefit to customers through the ERM and PCA.

The expense for natural gas purchased decreased $31.7 million due to a decrease in the price of natural gas (decreased costs $99.3 million), partially offset by an increase in total therms purchased (increased costs $67.6 million). Total therms purchased increased due to an increase in wholesale sales which are used to balance loads and resources as part of the natural gas procurement and resource optimization process, partially offset by a decrease in retail sales. We engage in optimization of available interstate pipeline transportation through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs.

Results of Operations - Alaska Electric Light and Power Company

Three months ended September 30, 2015 compared to the three months ended September 30, 2014

Net income for AEL&P was $0.4 million for the three months ended September 30, 2015 compared to $0.5 million for the three months ended September 30, 2014.

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

	Electric	
	2015	2014
Operating revenues	$ 9,273	$ 9,157
Resource costs	3,162	2,997
Gross margin	$ 6,111	$ 6,160

The following table presents AEL&P's utility electric operating revenues and megawatt-hour (MWh) sales for the three months ended September 30 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2015	2014	2015	2014
Residential	$ 3,109	$ 3,135	26	26
Commercial and government	5,969	5,829	62	61
Public street and highway lighting	68	73	—	1
Total retail	9,146	9,037	88	88
Other	127	120	—	—
Total	$ 9,273	$ 9,157	88	88

AEL&P’s operating revenues were $9.3 million and resource costs were $3.2 million, which resulted in gross margin of $6.1 million, all related to electric sales. AEL&P has a relatively stable load profile as it does not have a large population of customers in its service territory with electric heating and cooling requirements; therefore, their revenues are not as sensitive to weather fluctuations as Avista Utilities. However, AEL&P does have higher winter rates for its customers during the peak period of November through May of each year, which drives higher revenues during those periods. Government sales are similar to commercial sales in that they are primarily firm customers, but are government entities.

The following table presents AEL&P's average number of electric retail customers for the three months ended September 30:

	Electric Customers	
	2015	2014
Residential	14,397	14,242
Commercial and government	2,213	2,160
Public street and highway lighting	208	212
Total retail customers	16,818	16,614

The following table presents AEL&P's utility resource costs for the three months ended September 30 (dollars in thousands):

	Resource Costs	
	2015	2014
Snettisham power expenses	$ 2,699	$ 2,607
Cost of power adjustments, net	407	366
Fuel for generation	56	24
Total electric resource costs	$ 3,162	$ 2,997

Snettisham power expenses represent costs associated with operating the Snettisham hydroelectric project, including amounts paid under the take-or-pay power purchase agreement for the full capacity of this plant. This agreement is recorded as a capital lease on AEL&P's balance sheet, but reflected as an operating lease in the income statement. See "Note 9 of the Notes to Condensed Consolidated Financial Statements" for further information regarding this capital lease obligation.

Cost of power adjustments are primarily derived from certain revenues from interruptible or non-firm customers that are deferred and passed on for the benefit of firm customers in future periods. For instance, revenues from electric sales to cruise ships are passed back to firm customers at 100 percent. The amortization of these deferred balances flows through this account along with the original deferral.

Nine months ended September 30, 2015

As noted above, AEL&P was acquired on July 1, 2014; therefore, only the nine months ended September 30, 2015 are shown since there is not a full comparable period for 2014.

Net income for AEL&P was $4.0 million for the nine months ended September 30, 2015.

The following table presents AEL&P's operating revenues, resource costs and resulting gross margin for the nine months ended September 30, 2015 (dollars in thousands):

	Electric
Operating revenues	$ 32,279
Resource costs	9,282
Gross margin	$ 22,997

The following table presents AEL&P's utility electric operating revenues and megawatt-hour (MWh) sales for the nine months ended September 30, 2015 (dollars and MWhs in thousands):

	Electric Operating Revenues	Electric Energy MWh sales
Residential	$ 12,797	102
Commercial and government	18,943	193
Public street and highway lighting	144	1
Total retail	31,884	296
Other	395	—
Total	$ 32,279	296

AEL&P’s operating revenues were $32.3 million and resource costs were $9.3 million, which resulted in gross margin of $23.0 million, all related to electric sales. AEL&P has a relatively stable load profile as it does not have a large population of customers in its service territory with electric heating and cooling requirements; therefore, their revenues are not as sensitive to weather fluctuations as Avista Utilities. However, AEL&P does have higher winter rates for its customers during the peak period of November through May of each year, which drives higher revenues during those periods. Government sales are similar to commercial sales in that they are primarily firm customers, but are government entities.

The following table presents AEL&P's average number of electric retail customers for the nine months ended September 30, 2015:

	Electric Customers
Residential	14,252
Commercial and government	2,180
Public street and highway lighting	210
Total retail customers	16,642

The following table presents AEL&P's utility resource costs for the nine months ended September 30, 2015 (dollars in thousands):

	Resource Costs
Snettisham power expenses	$ 7,968
Cost of power adjustments, net	1,233
Fuel for generation	81
Total electric resource costs	$ 9,282

Snettisham power expenses represent costs associated with operating the Snettisham hydroelectric project, including amounts paid under the take-or-pay power purchase agreement for the full capacity of this plant. This agreement is recorded as a capital lease on AEL&P's balance sheet, but reflected as an operating lease in the income statement. See "Note 9 of the Notes to Condensed Consolidated Financial Statements" for further information regarding this capital lease obligation.

Cost of power adjustments are primarily derived from certain revenues from interruptible or non-firm customers that are deferred and passed on for the benefit of firm customers in future periods. For instance, revenues from electric sales to cruise ship are passed back to firm customers at 100 percent. The amortization of these deferred balances flows through this account along with the original deferral.

Results of Operations - Other Businesses

The following table shows our assets related to our other businesses as of September 30, 2015 and December 31, 2014 (dollars in thousands):

	September 30, 2015	December 31, 2014
Spokane Energy (1)	$ —	$ 30,404
METALfx	12,685	12,065
Steam Plant and Courtyard Office Center	7,021	7,278
Alaska companies (AERC and AJT Mining)	7,837	7,507
Avista Capital - standalone (2)	13,776	13,221
Other	9,878	9,735
Total	$ 51,197	$ 80,210

(1) The long-term fixed rate electric capacity contract, which expires in December 2016 was transferred from Spokane Energy to Avista Corp. during the second quarter of 2015. Spokane Energy was then dissolved during the third quarter of 2015.

(2) The balance at September 30, 2015 includes $13.8 million in escrow amounts related to the sale of Ecova. The escrow accounts were settled during October 2015 and we received the full amount of our portion of the escrow accounts.

Three months ended September 30, 2015 compared to the three months ended September 30, 2014

The net loss from these operations was $0.2 million for the three months ended September 30, 2015, compared to a net loss of $0.4 million for the three months ended September 30, 2014. The net loss for the third quarter of 2015 was primarily the result of $0.6 million (net of tax) of corporate costs, including costs associated with exploring strategic opportunities and net losses at AERC of $0.1 million. This was partially offset by net gains on investments of $0.2 million and net income at METALfx of $0.5 million for the third quarter of 2015, which compares to net income of $0.3 million for the third quarter of 2014.

Nine months ended September 30, 2015 compared to the nine months ended September 30, 2014

The net loss from these operations was $1.1 million for the nine months ended September 30, 2015, compared to net income of $3.5 million for the nine months ended September 30, 2014. The net loss for the first three quarters of 2015 was primarily the result of $1.6 million (net of tax) of corporate costs, including costs associated with exploring strategic opportunities, net losses on investments of $0.2 million and a net loss of $0.3 million at AERC. This was partially offset by METALfx net income of $1.2 million for the first nine months of 2015, which compares to net income of $0.6 million for the first nine months of 2014.

Results for the nine months ended September 30, 2014 included a $9.8 million net gain at Avista Energy related to the settlement of the California power markets litigation. The net gain from the litigation settlement was partially offset by a pre-tax contribution of $6.4 million of the proceeds to the Avista Foundation, a charitable organization funded by Avista Corp.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with GAAP requires us to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on our consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein. Our critical accounting policies that require the use of estimates and assumptions were discussed in detail in the Form 10-K for the year-ended December 31, 2014 and have not changed materially from that discussion.

Liquidity and Capital Resources

Overall Liquidity

Avista Corp.'s consolidated operating cash flows are primarily derived from the operations of Avista Utilities. The primary source of operating cash flows for Avista Utilities is revenues from sales of electricity and natural gas. Significant uses of cash flows from Avista Utilities include the purchase of power, fuel and natural gas, and payment of other operating expenses, taxes and interest, with any excess being available for other corporate uses such as capital expenditures and dividends.

We design operating and capital budgets to control operating costs and to direct capital expenditures to choices that support immediate and long-term strategies, particularly for our regulated utility operations. In addition to operating expenses, we have continuing commitments for capital expenditures for construction and improvement of utility facilities.

Our annual net cash flows from operating activities usually do not fully support the amount required for annual utility capital expenditures. As such, from time to time, we need to access long-term capital markets in order to fund these needs as well as fund maturing debt. See further discussion under “Capital Resources.”

We periodically file for rate adjustments for recovery of operating costs and capital investments and to seek the opportunity to earn reasonable returns as allowed by regulators. See further details in the section “Item 2: Management's Discussion and Analysis - Regulatory Matters.”

For Avista Utilities, when power and natural gas costs exceed the levels currently recovered from retail customers, net cash flows are negatively affected. Factors that could cause purchased power and natural gas costs to exceed the levels currently recovered from our customers include, but are not limited to, higher prices in wholesale markets when we buy energy or an increased need to purchase power in the wholesale markets. Factors beyond our control that could result in an increased need to purchase power in the wholesale markets include, but are not limited to:

- increases in demand (due to either weather or customer growth),
- low availability of streamflows for hydroelectric generation,
- unplanned outages at generating facilities, and
- failure of third parties to deliver on energy or capacity contracts.

Avista Utilities has regulatory mechanisms in place that provide for the deferral and recovery of the majority of power and natural gas supply costs. However, if prices rise above the level currently allowed in retail rates in periods when we are buying energy, deferral balances would increase, negatively affecting our cash flow and liquidity until such time as these costs, with interest, are recovered from customers.

In addition to the above, Avista Utilities enters into derivative instruments to hedge our exposure to certain risks, including fluctuations in commodity market prices, foreign exchange rates and interest rates (for purposes of issuing long-term debt in the future). These derivative instruments 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 the Company's credit ratings or changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against the Company's credit facilities and cash. See "Collateral Requirements" below.

We monitor the potential liquidity impacts of changes to energy commodity prices and other increased operating costs for our utility operations. We believe that we have adequate liquidity to meet such potential needs through our committed lines of credit.

As of September 30, 2015, we had $226.2 million of available liquidity under the Avista Corp. committed line of credit and $25.0 million under the AEL&P committed line of credit. With our $400.0 million credit facility that expires in April 2019 and AEL&P's $25.0 million credit facility that expires in November 2019, we believe that we have adequate liquidity to meet our needs for the next 12 months.

Review of Cash Flow Statement

Overall

During the nine months ended September 30, 2015, positive cash flows from operating activities were $311.2 million. Cash requirements included utility capital expenditures of $272.8 million, dividends of $61.8 million, contributions to our pension plan of $12.0 million and the settlement of interest rate swaps for $9.3 million.

Operating Activities

Net cash provided by operating activities was $311.2 million for the nine months ended September 30, 2015 compared to $265.7 million for the nine months ended September 30, 2014. Net income was $84.8 million for the nine months ended September 30, 2015 compared to $160.0 million for the nine months ended September 30, 2014. The decrease in net income was primarily due to a net gain of approximately $68.0 million related to the sale of Ecova which was recognized during 2014. In addition to the fluctuation in net income, there was an increase in depreciation and amortization of $6.6 million, primarily due to additions to utility plant and the inclusion of AERC in our 2015 financial results. Additionally, there was an increase in pension and other postretirement benefit expense of $10.8 million.

Net cash provided by fluctuations in certain current assets and liabilities was $65.9 million for the first nine months of 2015, compared to net cash provided of $56.9 million for the first nine months of 2014. The net cash provided by certain current assets and liabilities during the first nine months of 2015 primarily reflects positive cash flows related to a decrease in income taxes receivable (which resulted from the receipt of a tax refund in 2015 from our election of federal tax tangible property regulations in 2014) and a decrease in accounts receivable. These positive cash flows were partially offset by net cash outflows related to a decrease in accounts payable and an increase in deposits with counterparties.

The net cash provided by certain current assets and liabilities during the first nine months of 2014 primarily reflects positive cash flows related to accounts receivable, income taxes payable and other current liabilities (primarily related to fluctuations in accrued taxes, accrued interest, and other miscellaneous accrued liabilities). These positive cash flows were partially offset by net cash outflows related to accounts payable and materials and supplies, fuel stock and stored natural gas.

The gross gain on the sale of Ecova of $161.1 million for the first nine months of 2014 was excluded from operating cash flows and included in investing activities. Net deferrals of power and natural gas costs increased operating cash flows by $10.0 million for the nine months ended September 30, 2015 compared to a decrease in operating cash flows of $18.0 million for the nine months ended September 30, 2014. The benefit for deferred income taxes was $12.4 million for the nine months ended September 30, 2015 compared to $111.3 million for the nine months ended September 30, 2014. Contributions to our defined benefit pension plan were $12.0 million for the first nine months of 2015 and $32.0 million for the first nine months of 2014.

Investing Activities

Net cash used in investing activities was $271.1 million for the nine months ended September 30, 2015, compared to $6.8 million for the nine months ended September 30, 2014. During the first nine months of 2015, we paid $272.8 million for utility capital expenditures, an increase compared to $229.8 million for the first nine months of 2014.

During the first nine months of 2014, we received cash proceeds (net of cash sold and escrow amounts) of $229.9 million related to the sale of Ecova. A portion of the proceeds from the Ecova sale was used to pay off the balance of Ecova's long-term borrowings and make payments to option holders and noncontrolling interests (included in financing activities). We also used a portion of these proceeds to pay our tax liability associated with the gain on sale once it became due. We received $15.0 million in cash (net of cash paid) during 2014 in connection with the acquisition of AERC.

Prior to the sale on June 30, 2014, a significant portion of Ecova's funds were held as securities available for sale and they had purchases of $12.3 million, and sales and maturities of $14.6 million. In addition, during 2014 the fluctuation in the balance of funds held for customers resulted in a decrease to cash of $18.9 million.

Financing Activities

Net cash used in financing activities was $53.0 million for the nine months ended September 30, 2015 compared to net cash used of $331.1 million for the nine months ended September 30, 2014. During the first nine months of 2015, short-term borrowings on Avista Corp.'s committed line of credit increased $25.0 million, compared to a decrease of $136.0 million in the first nine months of 2014. Cash dividends paid to Avista Corp. shareholders increased to $61.8 million (or $0.99 per share) for the first nine months of 2015 from $58.6 million (or $0.9525 per share) for the first nine months of 2014. During the nine months ended September 30, 2015, we issued $1.4 million of common stock under the dividend reinvestment and direct stock purchase plan, and employee plans and we repurchased $2.9 million of common stock. During the nine months ended September 30, 2014, we issued $3.4 million of common stock and repurchased $61.0 million of common stock.

In connection with the execution of a purchase agreement for $100.0 million of first mortgage bonds that we will issue in December 2015, we cash-settled five interest rate swap contracts (notional amount of $75.0 million) during the nine months ended September 30, 2015 and paid a total of $9.3 million.

Net borrowings on Ecova's committed line of credit decreased $46.0 million during 2014 with $6.0 million in payments throughout the year and $40.0 million related to the close of the sale. In connection with the closing of the Ecova sale, we made cash payments of $54.2 million to noncontrolling interests and $20.9 million to stock option holders and redeemable noncontrolling interests of Ecova. The fluctuation in the balance of customer fund obligations at Ecova increased cash by $16.2 million in 2014.

In September 2014, AEL&P issued $75.0 million of long-term debt. The majority of the $39.4 million of redemptions and maturities of long-term debt in 2014 related to AEL&P paying off its existing debt.

Collateral Requirements

Avista Utilities' contracts for the purchase and sale of energy commodities can require collateral in the form of cash or letters of credit. As of September 30, 2015, we had cash deposited as collateral in the amount of $23.1 million and letters of credit of $26.2 million outstanding related to our energy derivative contracts. Price movements and/or a downgrade in our credit ratings could further impact the amount of collateral required. See “Credit Ratings” for further information. For example, in addition to limiting our ability to conduct transactions, if our credit ratings were lowered to below “investment grade” based on our positions outstanding at September 30, 2015, we would potentially be required to post additional collateral of up to $9.8 million. This amount is different from the amount disclosed in “Note 5 of the Notes to Condensed Consolidated Financial Statements” because, while this analysis includes contracts that are not considered derivatives in addition to the contracts considered in Note 5, this analysis takes into account contractual threshold limits that are not considered in Note 5. Without contractual threshold limits, we would potentially be required to post additional collateral of $27.8 million.

Under the terms of interest rate swap agreements that we enter into periodically, we may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the instrument. As of September 30, 2015, we had interest rate swap agreements outstanding with a notional amount totaling $425.0 million and we had deposited cash in the amount of $36.3 million and letters of credit of $10.7 million as collateral for these interest rate swap derivative contracts. If our credit ratings were lowered to below “investment grade” based on our interest rate swap agreements outstanding at September 30, 2015, we would be required to post additional collateral of $7.4 million.

Capital Resources

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings, and excluding noncontrolling interests, consisted of the following as of September 30, 2015 and December 31, 2014 (dollars in thousands):

	September 30, 2015		December 31, 2014	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt and capital leases	$ 93,105	2.9%	$ 6,424	0.2%
Current portion of nonrecourse long-term debt (Spokane Energy)	—	—%	1,431	0.1%
Short-term borrowings	130,000	4.1%	105,000	3.4%
Long-term debt to affiliated trusts	51,547	1.6%	51,547	1.6%
Long-term debt and capital leases	1,391,611	43.9%	1,492,062	47.5%
Total debt	1,666,263	52.5%	1,656,464	52.8%
Total Avista Corporation shareholders’ equity	1,508,553	47.5%	1,483,671	47.2%
Total	$ 3,174,816	100.0%	$ 3,140,135	100.0%

Our shareholders’ equity increased $24.9 million during the first nine months of 2015 primarily due to net income partially offset by the repurchase of common stock and dividends.

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

See "Item 2: Management's Discussion and Analysis, Executive Level Summary" for a detailed discussion of our 2015 capital expenditures through September 30, 2015, our expected capital expenditures for the remainder of 2015, 2016 and 2017, as well as our 2015 financing transactions through September 30, 2015 and our expected financing requirements for the remainder of 2015 and 2016.

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

	2015	2014
Borrowings outstanding at end of period	$ 130,000	$ 35,000
Letters of credit outstanding at end of period	$ 43,812	$ 45,614
Maximum borrowings outstanding during the period	$ 137,500	$ 171,000
Average borrowings outstanding during the period	$ 84,013	$ 55,778
Average interest rate on borrowings during the period	0.96%	1.03%
Average interest rate on borrowings at end of period	0.95%	0.92%

There were no borrowings outstanding under AEL&P's committed line of credit as of September 30, 2015 and September 30, 2014.

Any default on the line of credit or other financing arrangements of Avista Corp. or any of our “significant subsidiaries,” if any, could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Any defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock. Avista Corp. does not guarantee the indebtedness of any of its subsidiaries. As of September 30, 2015, Avista Corp. and its subsidiaries were in compliance with all of the covenants of their financing agreements, and none of Avista Corp.'s subsidiaries constituted a “significant subsidiary” as defined in Avista Corp.'s committed line of credit.

Capital Expenditures

The following table summarizes our expected future capital expenditures by year (in thousands):

	Avista Utilities	AEL&P
Expected total annual accrual-basis capital expenditures (by year)		
2015	375,000	14,000
2016	375,000	17,000
2017	400,000	13,000

Most of the capital expenditures at Avista Utilities are for upgrading our existing facilities and technology, and not for construction of new facilities. A significant portion of the capital expenditures at AEL&P are for the construction of an additional back-up generation plant. We expect all of these capital expenditures to be included in rate base in future years. These estimates of capital expenditures are subject to continuing review and adjustment. Actual capital expenditures may vary from our estimates due to factors such as changes in business conditions, construction schedules and environmental requirements.

Off-Balance Sheet Arrangements

As of September 30, 2015, we had $43.8 million in letters of credit outstanding under our $400.0 million committed line of credit, compared to $32.6 million as of December 31, 2014.

Pension Plan

Avista Utilities

In the nine months ended September 30, 2015 we contributed $12.0 million to the pension plan and we do not expect to make additional contributions during 2015. We expect to contribute a total of $60.0 million to the pension plan in the period 2015 through 2019, with an annual contribution of $12.0 million over that period.

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

Plan Assets

The Finance Committee of the Company’s Board of Directors approves investment policies, objectives and strategies that seek an appropriate return for the pension plan and other postretirement benefit plans and reviews and approves changes to the investment and funding policies.

During 2014, the Finance Committee approved changing the target investment allocation by allocating more of the investment target toward debt securities versus equity securities and absolute return. This investment strategy lowered the overall expected return on plan assets as well as the expected volatility related to investment returns, pension cost and funded status.

Credit Ratings

Our access to capital markets and our cost of capital are directly affected by our credit ratings. In addition, many of our contracts for the purchase and sale of energy commodities contain terms dependent upon our credit ratings. See “Collateral Requirements” and “Note 5 of the Notes to Condensed Consolidated Financial Statements.”

The following table summarizes our credit ratings as of November 3, 2015:

	Standard & Poor’s (1)	Moody’s (2)
Corporate/Issuer rating	BBB	Baa1
Senior secured debt	A-	A2
Senior unsecured debt	BBB	Baa1

(1) Standard & Poor’s lowest “investment grade” credit rating is BBB-.
(2) Moody’s lowest “investment grade” credit rating is Baa3.

A security rating is not a recommendation to buy, sell or hold securities. Each security rating is subject to revision or withdrawal at any time by the assigning rating organization. Each security rating agency has its own methodology for assigning ratings, and, accordingly, each rating should be considered in the context of the applicable methodology, independent of all other ratings. The rating agencies provide ratings at the request of Avista Corp. and charge fees for their services.

Dividends

The Board of Directors considers the level of dividends on our common stock on a regular basis, taking into account numerous factors including, without limitation:

- our results of operations, cash flows and financial condition,
- the success of our business strategies, and
- general economic and competitive conditions.

Avista Corp.'s net income available for dividends is generally derived from our regulated utility operations (Avista Utilities and AEL&P).

See "Note 1 of the Notes to Condensed Consolidated Financial Statements" for the items which could limit the payment of dividends on common stock.

On August 21, 2015, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.33 per share on the Company's common stock, which was equal to the previous quarter's dividend.

Contractual Obligations

Our future contractual obligations have not materially changed during the nine months ended September 30, 2015 except that on March 30, 2015, Avista Corp. provided a cancellation notice, effective May 31, 2015, to one of its information technology service providers. Even though this contractual obligation was terminated, new contractual obligations have been entered into resulting in a similar overall expense level. See the 2014 Form 10-K for other contractual obligations.

Economic Conditions

The general economic data, on both national and local levels, contained in this section is based, in part, on independent government and industry publications, reports by market research firms or other independent sources. While we believe that these publications and other sources are reliable, we have not independently verified such data and can make no representation as to its accuracy.

We track multiple economic indicators affecting three distinct metropolitan statistical areas in our Avista Utilities service area: Spokane, Washington, Coeur d'Alene, Idaho, and Medford, Oregon. Several key indicators are employment growth, unemployment rates and foreclosure rates. On a year-over-year basis, September 30, 2015 showed positive job growth, and lower unemployment rates in all three metropolitan areas. However, the unemployment rates in Spokane and Medford are still above the national average. With the exception of Medford, foreclosure rates are below the U.S rate, and key leading indicators, initial unemployment claims and residential building permits, continue to signal growth over the next 12 months. Therefore, for the full year 2015, we expect economic growth in our Avista Utilities service area to be slightly stronger than the U.S. as a whole.

Non-seasonally adjusted nonfarm employment in our eastern Washington, northern Idaho and southwestern Oregon metropolitan service areas exhibited strong growth between September 30, 2014 and September 30, 2015. In Spokane, Washington, employment growth was 2.7 percent with gains in all major employment sectors, except mining, logging and construction. Employment increased by 3.3 percent in Coeur d'Alene, Idaho, reflecting gains or stability in all major employment sectors, except information and leisure and hospitality. In Medford, Oregon, employment growth was 4.9 percent, with gains or stability in all major employment sectors, except construction. U.S. nonfarm employment grew by 2.0 percent in the same 12-month period.

Seasonally adjusted unemployment rates went down as of September 30, 2015 from the year earlier in Spokane, Coeur d'Alene, and Medford. In Spokane the rate was 7.5 percent as of September 30, 2014 and declined to 6.4 percent as of September 30, 2015; in Coeur d'Alene the rate went from 5.5 percent to 5.0 percent; and in Medford the rate declined from 8.6 percent to 7.4 percent. The U.S. rate declined from 5.9 percent to 5.1 percent in the same 12-month period.

The housing market in our Avista Utilities service area continues to experience foreclosure rates lower than or in line with the national average. The September 2015 national rate was 0.08 percent, compared to 0.05 percent in Spokane County, Washington; 0.03 percent in Kootenai County (Coeur d'Alene), Idaho; and 0.09 percent in Jackson County (Medford), Oregon.

Our AEL&P service area is centered in Juneau, Alaska. Although Juneau is Alaska's state capital, it is not a metropolitan statistical area. This means breadth and frequency of economic data is more limited. Therefore, the dates of Juneau's economic data may significantly lag the period of this filing.

The Quarterly Census of Employment and Wages for Juneau shows employment increased 1.3 percent between the first quarter 2014 and the first quarter 2015. Only financial activities; education and health services; government; and other services experienced employment declines. Between September 30, 2014 and September 30, 2015 the non-seasonally adjusted unemployment rate declined from 4.4 percent to 4.0 percent.

The Juneau foreclosure rate as of September 30, 2015 was not available.

Environmental Issues and Contingencies

Our environmental issues and contingencies disclosures have not materially changed except for the following during the nine months ended September 30, 2015. See the 2014 Form 10-K for all other environmental issues and contingencies.

Coal Ash Management/Disposal

On April 17, 2015, the EPA published a final rule regarding coal combustion residuals (CCRs), also termed coal combustion byproducts or coal ash in the Federal Register and this rule became effective on October 15, 2015. Colstrip, of which we are a 15 percent owner of units 3 and 4, produces this byproduct. The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste. We, in conjunction with the other Owners', are developing a multi-year compliance plan to strategically address the new CCR requirements and existing State obligations while maintaining operational stability. During the second quarter of 2015, the operator of Colstrip provided an initial cost estimate of the expected retirement costs associated with complying with the new CCR rule. Based on the initial assessment, Avista Corp. recorded an increase to its asset retirement obligations of $11.7 million with a corresponding increase in the cost basis of the utility plant.

In addition to an increase to our ARO, there is expected to be significant compliance costs in the future, both operating and capital costs, due to a series of incremental infrastructure improvements which are separate from any retirement obligations. Due to the preliminary nature of available data, we cannot reasonably estimate the future compliance costs; however, we will update our ARO and compliance cost estimates when data becomes available.

The actual asset retirement costs and future compliance costs related to the CCR Rule requirements may vary substantially from the estimates used to record the increased obligation due to uncertainty about the compliance strategies that will be used and the preliminary nature of available data used to estimate costs, such as the quantity of coal ash present at certain sites and the volume of fill that will be needed to cap and cover certain impoundments. We will coordinate with the plant operators and continue to gather additional data in future periods to make decisions about compliance strategies and the timing of closure activities. As additional information becomes available, we will update the ARO and future nonretirement compliance costs for these changes in estimates, which could be material. We expect to seek recovery of any increased costs related to complying with the new rule through customer rates.

Clean Air Act (CAA)

Hazardous Air Pollutants (HAPs)

The EPA regulates hazardous air pollutants from a published list of industrial sources referred to as "source categories" which must meet control technology requirements if they emit one or more of the pollutants in significant quantities. In 2012, the EPA finalized the Mercury Air Toxic Standards (MATS) for the coal and oil-fired source category. At the time of issuance in 2012, we examined the existing emission control systems of Colstrip Units 3 & 4, the only units in which we are a minority owner, and concluded that the existing emission control systems should be sufficient to meet mercury limits. For the remaining portion of the rule that utilized Particulate Matter as a surrogate for air toxics (including metals and acid gases), the Colstrip owners reviewed recent stack testing data and expected that no additional emission control systems would be needed for Units 3 & 4 MATS compliance.

On June 29, 2015, the Supreme Court held that the EPA interpreted unreasonably when it deemed cost irrelevant for MATS regulation. MATS has been reversed and remanded.

Regional Haze Program

The EPA set a national goal of eliminating man-made visibility degradation in Class I areas by the year 2064. States are expected to take actions to make "reasonable progress" through 10-year plans, including application of Best Available Retrofit Technology (BART) requirements. BART is a retrofit program applied to large emission sources, including electric generating units built between 1962 and 1977. In the case where a State opts out of implementing the Regional Haze program, the EPA may act directly. On September 18, 2012, the EPA finalized the Regional Haze federal implementation plan (FIP) for Montana. The FIP includes both emission limitations and pollution controls for Colstrip Units 1 & 2. Colstrip Units 3 & 4, the only units of which we are a minority owner, are not currently affected, but will be evaluated for Reasonable Progress at the next review period in September 2017. We do not anticipate any material impacts on Units 3 & 4 at this time. In November 2012, the National Parks Conservation Association, MEIC and Sierra Club filed a petition for review of the EPA's Montana FIP in the U.S. Court of Appeals for the Ninth Circuit.

On June 9, 2015, in the Petition for Review of an Order of the Environmental Protection Agency before the U.S. Court of Appeals for the Ninth Circuit, the panel vacated the portions of the Final Rule setting emissions limits at Colstrip Units 1 & 2 and Corette, and remanded back to the EPA for further proceedings.

Federal Regulatory Actions

The EPA released the final rules for the Clean Power Plan (Final CPP) and the Carbon Pollution Standards (Final CPS) on August 3, 2015. The Final CPP and the Final CPS are both intended to reduce the carbon dioxide (CO2) emissions from certain coal-fired and natural gas electric generating units (EGUs). These rules were published in the Federal Register on October 23, 2015 and were immediately challenged via lawsuits by other parties.

The Final CPP was promulgated pursuant to Section 111(d) of the CAA and applies to CO2 emissions from existing EGUs. The Final CPP is intended to reduce national CO2 emissions by approximately 32 percent below 2005 levels by 2030. The Final CPS rule was issued pursuant to Section 111(b) of the CAA and applies to the emissions of new, modified and reconstructed EGUs. The two rules are the first rules ever adopted by the U.S. federal government to comprehensively control and reduce CO2 emissions from the power sector. The EPA also issued a proposed Federal Implementation Plan (Proposed FIP) for the Final CPP. The Final FIP that the EPA adopts could be imposed on states by the EPA, should a state decide not to develop its own plan.

The Final CPP establishes individual state emission reduction goals based upon the assumed potential for (1) heat rate improvements at coal-fired units, (2) increased utilization of natural gas-fired combined cycle plants, and (3) increased utilization of low or zero carbon emitting generation resources. States have until June 2016 to submit state compliance plans, with a potential for two-year extensions. Avista Corp. owns two EGUs that are subject to the Final CPP: its portion (15 percent of Units 3 & 4) of Colstrip in Montana and Coyote Springs 2 in Oregon. States may adopt rate-based or mass-based plans, and may choose to focus compliance on specific EGUs or adopt broader measures to reduce carbon emissions from this sector. The states in which Avista Corp. generates or delivers electricity, Washington, Idaho, Montana and Oregon, are all evaluating options for developing state plans, which will define compliance approaches and obligations. Alaska was exempted in the Final CPP. The EPA may consider rulemaking for Alaska and Hawaii, both states which lack regional grid connections, in the future.

In a separate but related rulemaking, the EPA finalized CO2 new source performance standards (NSPS) for new, modified and reconstructed fossil fuel-fired EGUs under CAA section 111(b). These EGUs fall into the same two categories of sources regulated by the Final CPP: steam generating units (also known as “utility boilers and IGCC units”), which primarily burn coal, and stationary combustion turbines, which primarily burn natural gas.

GHG emission standards could result in significant compliance costs. Such standards could also preclude us from developing, operating or contracting with certain types of generating plants. Additionally, the Climate Action Plan requirements related to preparing the U.S. for the impacts of climate change could affect us and others in the industry as transmission system modifications to improve resiliency may be needed in order to meet those requirements. The promulgated and proposed GHG rulemakings mentioned above have been legally challenged in multiple venues, so we cannot fully predict the outcome or estimate the extent to which our facilities may be impacted by these regulations at this time. We intend to seek recovery of any costs related to compliance with these requirements through the ratemaking process.

Climate Change - State Legislation and State Regulatory Activities

Washington State Governor Jay Inslee has instructed the Department of Ecology (Ecology) to undertake rulemaking, using existing authorities, to reduce carbon emissions across the State in pursuit of the State’s carbon goals, which were enacted in 2008 by the Legislature. The governor’s emissions cap rule is expected to apply to sources of annual greenhouse emissions in excess of 100,000 tons, including stationary sources and transportation fuel suppliers, as well as to natural gas distribution companies. Ecology has identified 30 entities responsible for 60 percent of the state’s emission sources that would be regulated under the proposed rule. Other than the combustion associated with the natural gas Avista Corp. distributes, the rule does not appear to capture any other Avista Corp. facilities or activities. The Governor ordered Ecology to prepare draft rules by December 2015 and final rules by June 2016.

An Initiative to the Legislature (I-732), which would impose a carbon tax on fossil-fueled generation and natural gas distribution, as well as on transportation fuels, seems likely to gain sufficient signatures to be considered by the Legislature. Sponsors of the initiative have until December 31, 2015, to submit petitions to the Office of the Secretary of State for signature validation and for consideration during the 2016 Legislative Session. In addition, a coalition of environmental and labor groups in Washington announced its intent to file an initiative at the start of 2016 that would impose fees on carbon emissions from fossil fuels and spend proceeds on clean-energy investments and other government programs. If filed and if it gains sufficient signatures, this initiative would go on the general ballot in 2016. While we cannot predict the eventual outcome of actions arising out of proposed legislation at this time or estimate the effect thereof, we will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to our generation assets.

In Oregon, two initiatives have been filed, both aimed at companies that provide electric utility services in that state. While Avista Corp. is not an electric utility in Oregon, its shared ownership of Colstrip with Portland General Electric and Pacificorp makes these initiatives of interest. Initiative 63 requires large electric companies to eliminate all coal-fired resources from its electricity supply by 2030. The initiative additionally requires, among other things, electric companies to supply new energy production from renewable sources in graduated steps. Initiative 64 is almost identical to Initiative 63 in terms of requiring the elimination of coal-fired resources by 2030. In addition, this initiative targets executive pay; in any year the electric company fails to meet the standards relating to the amount of qualifying electricity sold to consumers, the Chief Executive Officer and Chief Financial Officer will have their compensation restricted. Each of these two positions, or the equivalent to such positions, may not receive any compensation from the electric company, or an entity affiliated with that electric company, in an amount exceeding five times the annual Oregon median household income from the preceding year. While we cannot predict the eventual outcome of actions arising out of the filed initiatives at this time or estimate the effect thereof, we will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to our generation assets.

Other

For other environmental issues and other contingencies see “Note 13 of the Notes to Condensed Consolidated Financial Statements.”

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our primary market risk exposures are:

- Commodity prices for electric power and natural gas
- Credit related to the wholesale energy market
- Interest rates on long-term and short-term debt
- Foreign exchange rates between the U.S. dollar and the Canadian dollar

Commodity Price Risk

Our qualitative commodity price risk disclosures have not materially changed during the nine months ended September 30, 2015. Refer to the 2014 Form 10-K. The following table presents energy commodity derivative fair values as a net asset or (liability) as of September 30, 2015 that are expected to settle in each respective year (dollars in thousands):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
2015	$ (2,282)	$ (6,869)	$ (3,239)	$ (13,598)	$ 4	$ 9,848	$ 322	$ 6,749
2016	(6,177)	(11,585)	(4,930)	(31,517)	(11)	23,502	195	17,401
2017	(5,842)	—	(853)	(7,290)	(27)	3,352	(1,042)	473
2018	(5,624)	—	—	(2,739)	(43)	—	(1,196)	(125)
2019	(3,263)	—	—	(1,594)	(36)	—	(1,087)	—
Thereafter	—	—	—	—	—	—	(1,737)	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2014 that are expected to be delivered in each respective year (dollars in thousands):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
2015	$ (6,053)	$ (27,664)	$ (10,607)	$ (50,852)	$ 17	$ 32,629	$ 1,228	$ 31,661
2016	(5,978)	(5,124)	(2,970)	(19,381)	(80)	13,126	(853)	10,170
2017	(4,657)	—	(355)	(2,428)	(117)	1,151	—	119
2018	(4,173)	—	—	(389)	(120)	—	—	—
2019	(2,191)	—	—	(147)	(85)	—	—	—
Thereafter	—	—	—	—	—	—	—	—

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

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

Credit Risk

Our credit risk has not materially changed during the nine months ended September 30, 2015. See the 2014 Form 10-K.

Risk Management for Energy Resources

We use a variety of techniques to manage risks for energy resources and wholesale energy market activities. We have an energy resources risk policy, which includes our wholesale energy markets credit policy and control procedures to manage these risks, both qualitative and quantitative. The 2014 Form 10-K contains a discussion of risk management policies and procedures.

Interest Rate Risk

We use a variety of techniques to manage our interest rate risks. We have an interest rate risk policy and have established a policy to limit our variable rate exposures to a percentage of total capitalization. Additionally, interest rate risk is managed by monitoring market conditions when timing the issuance of long-term debt and optional debt redemptions and through the use of fixed rate long-term debt with varying maturities. The 2014 Form 10-K contains a discussion of risk management policies and procedures.

The following table summarizes our interest rate swap agreements that we have entered into as of September 30, 2015 and December 31, 2014 (dollars in thousands):

	September 30, 2015	December 31, 2014
Number of agreements	21	22
Notional amount	$ 425,000	$ 420,000
Mandatory cash settlement dates	2016 to 2019	2015 to 2018
Short-term derivative assets (1)	$ —	$ 460
Short-term derivative liability (1) (2)	(7,344)	(7,325)
Long-term derivative liability (1) (2)	(44,359)	(40,857)

(1) There are offsetting regulatory assets and liabilities for these items on the Condensed Consolidated Balance Sheets in accordance with regulatory accounting practices.
(2) The balances as of September 30, 2015 and December 31, 2014 reflect the offsetting of $36.3 million and $28.9 million, respectively of cash collateral against the net derivative positions where a legal right of offset exists.

Foreign Currency Risk

Our qualitative foreign currency risk disclosures have not materially changed during the nine months ended September 30, 2015. See the 2014 Form 10-K.

The following table summarizes the foreign currency hedges that we have outstanding as of September 30, 2015 and December 31, 2014 (dollars in thousands):

	September 30, 2015	December 31, 2014
Number of contracts	23	18
Notional amount (in United States currency)	$ 10,140	$ 5,474
Notional amount (in Canadian currency)	13,438	6,198
Other current derivative liability	(65)	(20)

Further information for derivatives and fair values is disclosed at “Note 5 of the Notes to Condensed Consolidated Financial Statements” and “Note 11 of the Notes to Condensed Consolidated Financial Statements.”

Item 4. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended) (Act) that are designed to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company’s management, including its principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. With the participation of the Company’s principal executive officer and principal financial officer, the Company's management evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon this evaluation, the Company’s principal executive officer and principal financial officer have concluded that the Company’s disclosure controls and procedures are effective at a reasonable assurance level as of September 30, 2015.

There have been no changes in the Company's internal control over financial reporting that occurred during the third quarter of 2015 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. Other Information

Item 1. Legal Proceedings

See “Note 13 of Notes to Condensed Consolidated Financial Statements” in “Part I. Financial Information Item 1. Condensed Consolidated Financial Statements.”

Item 1A. Risk Factors

Please refer to the 2014 Form 10-K for disclosure of risk factors that could have a significant impact on our results of operations, financial condition or cash flows and could cause actual results or outcomes to differ materially from those discussed in our reports filed with the Securities and Exchange Commission (including this Quarterly Report on Form 10-Q), and elsewhere. These risk factors have not materially changed from the disclosures provided in the 2014 Form 10-K.

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

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) Not applicable

(b) Not applicable

(c) Not applicable

Dividend Limitations

We have certain covenants applicable to our preferred stock, long-term debt and committed line of credit as well as limitations imposed by the hydroelectric licensing requirements of section 10(d) of the FPA and the OPUC approval of the AERC acquisition, which could limit the amount of dividends we can pay on our common stock. See "Item 2. Management's Discussion and Analysis: Dividends" and "Note 1 of the Notes to Condensed Consolidated Financial Statements" for further discussion of these limitations.

Item 4. Mine Safety Disclosures

Not applicable.

Item 6. Exhibits

12	Computation of ratio of earnings to fixed charges*
15	Letter Re: Unaudited Interim Financial Information*
31.1	Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002)*
31.2	Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002)*
32	Certification of Corporate Officers (Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)**
101	The following financial information from the Quarterly Report on Form 10−Q for the period ended September 30, 2015, formatted in XBRL (Extensible Business Reporting Language) and filed electronically herewith: (i) the Condensed Consolidated Statements of Income; (ii) Condensed Consolidated Statements of Comprehensive Income; (iii) the Condensed Consolidated Balance Sheets; (iv) the Condensed Consolidated Statements of Cash Flows; (v) the Condensed Consolidated Statements of Equity and Redeemable Noncontrolling Interests; and (vi) the Notes to Condensed Consolidated Financial Statements.*

* Filed herewith.

** Furnished herewith.

SIGNATURE

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

AVISTA CORPORATION
(Registrant)

Date: November 3, 2015

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

Exhibit 12

AVISTA CORPORATION

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

	Nine months ended September 30, 2015	Years Ended December 31 2014	2013	2012	2011	2010
Fixed charges, as defined:						
Interest charges	$ 60,181	$ 74,025	$ 73,772	$ 71,843	$ 69,536	$ 71,734
Amortization of debt expense and premium - net	2,567	3,635	3,813	3,803	4,617	4,414
Interest portion of rentals	970	1,187	1,146	1,294	1,139	1,248
Total fixed charges	$ 63,718	$ 78,847	$ 78,731	$ 76,940	$ 75,292	$ 77,396
Earnings, as defined:						
Pre-tax income from continuing operations	$ 131,672	$ 192,106	$ 162,347	$ 116,567	$ 139,438	$ 130,536
Add (deduct):						
Capitalized interest	(2,701)	(3,924)	(3,676)	(2,401)	(2,942)	(298)
Total fixed charges above	63,718	78,847	78,731	76,940	75,292	77,396
Total earnings	$ 192,689	$ 267,029	$ 237,402	$ 191,106	$ 211,788	$ 207,634
Ratio of earnings to fixed charges	3.02	3.39	3.02	2.48	2.81	2.68

Exhibit 15

November 3, 2015

Avista Corporation
Spokane, Washington

We have reviewed, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the unaudited interim financial information of Avista Corporation and subsidiaries for the periods ended September 30, 2015 and 2014, as indicated in our report dated November 3, 2015; because we did not perform an audit, we expressed no opinion on that information.

We are aware that our report referred to above, which is included in your Quarterly Report on Form 10-Q for the quarter ended September 30, 2015, is incorporated by reference in Registration Statement Nos. 333-33790, 333-126577 and 333-179042 on Form S-8 and in Registration Statement No. 333-187306 on Form S-3.

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

/s/ Deloitte & Touche LLP

Seattle, Washington

Exhibit 31.1

CERTIFICATION

I, Scott L. Morris, certify that:

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

Date: November 3, 2015

/s/ Scott L. Morris
Scott L. Morris
Chairman of the Board, President
and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Mark T. Thies, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: November 3, 2015

/s/ Mark T. Thies

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

Exhibit 32

AVISTA CORPORATION

CERTIFICATION OF CORPORATE OFFICERS

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

Sarbanes-Oxley Act of 2002)

Each of the undersigned, Scott L. Morris, Chairman of the Board, President and Chief Executive Officer of Avista Corporation (the “Company”), and Mark T. Thies, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2015 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 3, 2015

/s/ Scott L. Morris

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

/s/ Mark T. Thies

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