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

Form 10-Q

(Mark One)

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

FOR THE QUARTERLY PERIOD ENDED March 31, 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 ☒ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, 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	☒	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 ☒

As of April 30, 2015, 62,273,807 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 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 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, avalanches 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;
- our ability to fully collect the indemnification escrow amounts because of information that was covered under management's representations and warranties related to the Ecova sale which could be inaccurate or incomplete at the time of sale, or because of new information which could be identified subsequent to the sale date, 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 effect 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.

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CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Three Months Ended March 31
Dollars in thousands, except per share amounts
(Unaudited)

	2015	2014
Operating Revenues:		
Utility revenues	$ 436,407	$ 437,124
Non-utility revenues	10,083	9,454
Total operating revenues	446,490	446,578
Operating Expenses:		
Utility operating expenses:		
Resource costs	209,560	220,497
Other operating expenses	73,172	67,337
Depreciation and amortization	34,300	30,726
Taxes other than income taxes	29,898	28,146
Non-utility operating expenses:		
Other operating expenses	9,816	9,383
Depreciation and amortization	169	147
Total operating expenses	356,915	356,236
Income from continuing operations	89,575	90,342
Interest expense	19,902	18,744
Interest expense to affiliated trusts	112	111
Capitalized interest	(917)	(661)
Other income-net	(2,231)	(2,600)
Income from continuing operations before income taxes	72,709	74,748
Income tax expense	26,247	27,282
Net income from continuing operations	46,462	47,466
Net income from discontinued operations (Note 4)	—	1,515
Net income	46,462	48,981
Net income attributable to noncontrolling interests	(13)	(482)
Net income attributable to Avista Corp. shareholders	$ 46,449	$ 48,499

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (continued)

Avista Corporation

For the Three Months Ended March 31
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	$ 46,449	$ 47,476
Net income from discontinued operations attributable to Avista Corp. shareholders	—	1,023
Net income attributable to Avista Corp. shareholders	$ 46,449	$ 48,499
Weighted-average common shares outstanding (thousands), basic	62,318	60,122
Weighted-average common shares outstanding (thousands), diluted	62,889	60,168
Earnings per common share attributable to Avista Corp. shareholders, basic:		
Earnings per common share from continuing operations	$ 0.75	$ 0.79
Earnings per common share from discontinued operations	—	0.02
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 0.75	$ 0.81
Earnings per common share attributable to Avista Corp. shareholders, diluted:		
Earnings per common share from continuing operations	$ 0.74	$ 0.79
Earnings per common share from discontinued operations	—	0.02
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 0.74	$ 0.81
Dividends declared per common share	$ 0.33	$ 0.3175

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

For the Three Months Ended March 31
Dollars in thousands
(Unaudited)

	2015	2014
Net income	$ 46,462	$ 48,981
Other Comprehensive Income (Loss):		
Unrealized investment gains - net of taxes of $0 and $463, respectively	—	785
Reclassification adjustment for realized gains on investment securities included in net income from discontinued operations - net of taxes of $0 and $(1), respectively	—	(2)
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $132 and $59, respectively	246	111
Total other comprehensive income	246	894
Comprehensive income	46,708	49,875
Comprehensive income attributable to noncontrolling interests	(13)	(482)
Comprehensive income attributable to Avista Corporation shareholders	$ 46,695	$ 49,393

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands
(Unaudited)

		March 31, 2015		December 31, 2014
Assets:				
Current Assets:				
Cash and cash equivalents	$	22,081	$	22,143
Accounts and notes receivable-less allowances of $6,481 and $4,888, respectively		162,203		171,925
Utility energy commodity derivative assets		1,579		1,525
Regulatory asset for utility derivatives		16,058		29,640
Materials and supplies, fuel stock and natural gas stored		43,785		66,356
Deferred income taxes		20,589		14,794
Income taxes receivable		562		43,893
Other current assets		43,639		45,071
Total current assets		310,496		395,347
Net Utility Property:				
Utility plant in service		4,858,902		4,718,062
Construction work in progress		148,291		227,758
Total		5,007,193		4,945,820
Less: Accumulated depreciation and amortization		1,356,114		1,325,858
Total net utility property		3,651,079		3,619,962
Other Non-current Assets:				
Investment in exchange power-net		10,821		11,433
Investment in affiliated trusts		11,547		11,547
Goodwill		57,976		57,976
Long-term energy contract receivable of Spokane Energy		24,931		28,202
Other property and investments-net		41,413		42,016
Total other non-current assets		146,688		151,174
Deferred Charges:				
Regulatory assets for deferred income tax		98,606		100,412
Regulatory assets for pensions and other postretirement benefits		232,721		235,758
Other regulatory assets		95,618		91,920
Regulatory asset for unsettled interest rate swaps		112,835		77,063
Non-current regulatory asset for utility derivatives		24,145		24,483
Other deferred charges		16,841		16,212
Total deferred charges		580,766		545,848
Total assets	$	4,689,029	$	4,712,331

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

Dollars in thousands
(Unaudited)

	March 31, 2015	December 31, 2014
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 62,853	$ 112,974
Current portion of long-term debt and capital leases	3,132	6,424
Current portion of nonrecourse long-term debt of Spokane Energy	—	1,431
Short-term borrowings	65,000	105,000
Utility energy commodity derivative liabilities	14,178	18,045
Income taxes payable	20,335	173
Other current liabilities	160,130	141,222
Total current liabilities	325,628	385,269
Long-term debt and capital leases	1,495,546	1,492,062
Long-term debt to affiliated trusts	51,547	51,547
Regulatory liability for utility plant retirement costs	257,146	254,140
Pensions and other postretirement benefits	188,798	189,489
Deferred income taxes	714,440	710,342
Other non-current liabilities and deferred credits	149,165	146,240
Total liabilities	3,182,270	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; 62,271,133 and 62,243,374 shares outstanding	998,975	999,960
Accumulated other comprehensive loss	(7,642)	(7,888)
Retained earnings	515,842	491,599
Total Avista Corporation shareholders' equity	1,507,175	1,483,671
Noncontrolling Interests	(416)	(429)
Total equity	1,506,759	1,483,242
Total liabilities and equity	$ 4,689,029	$ 4,712,331

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

For the Three Months Ended March 31
Dollars in thousands
(Unaudited)

	2015	2014
Operating Activities:		
Net income	$ 46,462	$ 48,981
Non-cash items included in net income:		
Depreciation and amortization	35,379	34,582
Provision (benefit) for deferred income taxes	(82)	1,453
Power and natural gas cost amortizations (deferrals), net	8,196	(8,041)
Amortization of debt expense	895	953
Amortization of investment in exchange power	613	613
Stock-based compensation expense	1,707	1,551
Equity-related AFUDC	(2,215)	(2,034)
Pension and other postretirement benefit expense	9,217	7,415
Amortization of Spokane Energy contract	3,271	3,007
Other	(3,077)	4,212
Contributions to defined benefit pension plan	(4,000)	(11,000)
Changes in certain current assets and liabilities:		
Accounts and notes receivable	2,664	17,257
Materials and supplies, fuel stock and natural gas stored	22,571	12,141
Decrease (increase) in collateral posted for derivative instruments	(18,516)	26,756
Income taxes receivable	43,331	7,783
Other current assets	471	(1,494)
Accounts payable	(30,545)	(11,065)
Income taxes payable	20,162	19,412
Other current liabilities	10,274	4,416
Net cash provided by operating activities	146,778	156,898
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(81,597)	(59,725)
Other capital expenditures	(412)	(3,929)
Federal and state grant payments received	943	876
Increase in funds held for clients	—	(9,346)
Sale and maturity of securities available for sale	—	11,403
Other	891	24
Net cash used in investing activities	(80,175)	(60,697)

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

For the Three Months Ended March 31
Dollars in thousands
(Unaudited)

	2015	2014
Financing Activities:		
Net decrease in short-term borrowings	$ (40,000)	$ (60,000)
Repayment of borrowings from Ecova line of credit	—	(4,000)
Redemption and maturity of long-term debt	(639)	(69)
Maturity of nonrecourse long-term debt of Spokane Energy	(1,431)	(3,966)
Issuance of common stock, net of issuance costs	371	638
Repurchase of common stock	(2,920)	—
Cash dividends paid	(20,717)	(19,217)
Decrease in client fund obligations	—	(1,989)
Other	(1,329)	—
Net cash used in financing activities	(66,665)	(88,603)
Net increase (decrease) in cash and cash equivalents	(62)	7,598
Cash and cash equivalents at beginning of period	22,143	82,574
Cash and cash equivalents at end of period	$ 22,081	$ 90,172

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS

Avista Corporation

For the Three Months Ended March 31
Dollars in thousands
(Unaudited)

	2015	2014
Common Stock, Shares:		
Shares outstanding at beginning of period	62,243,374	60,076,752
Shares issued	117,159	84,388
Shares repurchased	(89,400)	—
Shares outstanding at end of period	62,271,133	60,161,140
Common Stock, Amount:		
Balance at beginning of period	$ 999,960	$ 896,993
Equity compensation expense	1,513	1,619
Issuance of common stock, net of issuance costs and excess tax benefits	413	638
Payment of minimum tax withholdings for share-based payment awards	(1,480)	—
Repurchase of common stock	(1,431)	—
Equity transactions of consolidated subsidiaries	—	(213)
Balance at end of period	998,975	899,037
Accumulated Other Comprehensive Loss:		
Balance at beginning of period	(7,888)	(5,819)
Other comprehensive income	246	894
Balance at end of period	(7,642)	(4,925)
Retained Earnings:		
Balance at beginning of period	491,599	407,092
Net income attributable to Avista Corporation shareholders	46,449	48,499
Cash dividends paid (common stock)	(20,717)	(19,217)
Repurchase of common stock	(1,489)	—
Valuation adjustments and other noncontrolling interests activity	—	(4)
Balance at end of period	515,842	436,370
Total Avista Corporation shareholders' equity	1,507,175	1,330,482
Noncontrolling Interests:		
Balance at beginning of period	(429)	20,001
Net income attributable to noncontrolling interests	13	458
Other	—	172
Balance at end of period	(416)	20,631
Total equity	$ 1,506,759	$ 1,351,113
Redeemable Noncontrolling Interests:		
Balance at beginning of period	$ —	$ 15,889
Net income attributable to noncontrolling interests	—	24
Purchase of subsidiary noncontrolling interests	—	(3)
Valuation adjustments and other noncontrolling interests activity	—	50
Balance at end of period	$ —	$ 15,960

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 March 31, 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 (U.S. 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 is 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. in the first half of 2014. See Note 3 for information regarding the acquisition of AERC.

Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility businesses, except Spokane Energy, LLC (Spokane Energy). 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 12 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 net 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 months ended March 31 (dollars in thousands):

	2015	2014
Utility taxes	$ 19,498	$ 19,738

Other Income-Net

Other income-net consisted of the following items for the three months ended March 31 (dollars in thousands):

	2015	2014
Interest income	$ 243	$ 274
Interest income on regulatory deferrals	20	44
Equity-related AFUDC	2,215	2,034
Net loss on investments	(384)	(40)
Other income	137	288
Total	$ 2,231	$ 2,600

Materials and Supplies, Fuel Stock and Natural Gas Stored

Inventories of materials and supplies, fuel stock and natural gas stored 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 March 31, 2015 and December 31, 2014 (dollars in thousands):

	March 31, 2015	December 31, 2014
Materials and supplies	$ 33,271	$ 32,483
Fuel stock	5,508	5,142
Natural gas stored	5,006	28,731
Total	$ 43,785	$ 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 three months ended March 31, 2014 (dollars in thousands):

	2014
Proceeds from sales, maturities and calls	$ 11,403
Gross realized gains	3

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. This is similar to the treatment of energy commodity derivatives described above. 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 to sell 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, investments and funds held for clients, 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 9 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. 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, and
- precluded from the future deferral of costs not recovered through rates at the time such costs are incurred, even if the Company expected to recover such costs in the future.

Accumulated Other Comprehensive Loss

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

	March 31, 2015	December 31, 2014
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $(4,115) and $(4,247), respectively	$ (7,642)	$ (7,888)

The following table details the reclassifications out of accumulated other comprehensive loss by component for the three months ended March 31 (dollars in thousands). Items in parenthesis indicate reductions to net income.

Details about Accumulated Other Comprehensive Loss Components	Amounts Reclassified from Accumulated Other Comprehensive Loss 2015	2014	Affected Line Item in Statement of Income
Realized gains on investment securities	$ —	$ 3	(a)
	—	3	Total before tax
	—	(1)	Tax expense (a)
	$ —	$ 2	Net of tax
Amortization of defined benefit pension items			
Amortization of net prior service cost	$ 273	$ 38	(b)
Amortization of net loss	(3,688)	(1,990)	(b)
Adjustment due to effects of regulation	3,037	1,782	(b)
	(378)	(170)	Total before tax
	132	59	Tax benefit
	$ (246)	$ (111)	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 6 for additional details).

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 (see Note 1), and
- certain requirements under the Public Utility Commission of Oregon (OPUC) approval of the AERC acquisition. After 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 March 31, 2015 was limited to approximately $414.3 million.

Under the requirements of the OPUC approval of the AERC acquisition as outlined above, the amount available for dividends at March 31, 2015 was limited to approximately $278.4 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). The number of shares repurchased through the first quarter 2015 program were in addition to the number of shares repurchased during 2014 under a separate stock repurchase program, which expired on December 31, 2014. The parameters of the first quarter 2015 program were consistent with the parameters of the 2014 program. Through March 31, 2015, the Company repurchased 89,400 shares under the first quarter 2015 program 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 March 31, 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 and Condensed Consolidated Balances Sheets 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," "Income taxes receivable," and "Income taxes payable" were added as their own line items. These were previously included in "Other current assets" and "Other current liabilities" in the operating activities section. In the current year Condensed Consolidated Balance Sheets, "Income taxes payable" was added as its own line item. This was previously included in "Other current liabilities."

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 is effective for periods beginning on or after December 15, 2014; however, early adoption is 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 is effective for periods beginning after December 15, 2016 and early adoption is not permitted. However, while this ASU is not effective until 2017, it will require retroactive application to all periods presented in the financial statements. As such, at adoption in 2017, amounts in 2015 and 2016 may have to be revised or a cumulative adjustment to opening retained earnings may have to be recorded. The Company is currently 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. This ASU 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 evaluated this standard and determined that it would not early adopt this standard during the first quarter of 2015. Upon adoption, the Company will revise its current presentation of debt issuance costs in the Condensed Consolidated Balance Sheets; however, the Company does not expect a material impact on its future financial condition, results of operations and cash flows as a result of the adoption.

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.

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 16,452 customers in the City and Borough of Juneau (CBJ), 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):

	July 1, 2014
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	4,697
Fair value of total consideration transferred	$ 154,816

The estimated fair value of assets acquired and liabilities assumed as of July 1, 2014 have not changed from the amounts disclosed in the Company's 2014 Form 10-K. The transaction resulted in the recording of $52.7 million in goodwill during 2014. The goodwill associated with this acquisition is not deductible for tax purposes.

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.

The following table summarizes the supplemental pro forma information for the three months ended March 31, 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):

	Actual 2015	Pro forma 2014
Actual Avista Corp. revenues from continuing operations (excluding AERC)	$ 433,699	$ 446,578
Supplemental pro forma AERC revenues (1)	12,791	13,186
Total pro forma revenues	446,490	459,764
Actual AERC revenues included in Avista Corp. revenues (1)	12,791	—
Actual Avista Corp. net income from continuing operations attributable to Avista Corp. shareholders (excluding AERC)	43,918	47,476
Actual Avista Corp. net income from discontinued operations attributable to Avista Corp. shareholders	—	1,023
Adjustment to Avista Corp.'s net income for acquisition costs (net of tax) (2)	5	294
Supplemental pro forma AERC net income (1)	2,531	3,256
Total pro forma net income	46,454	52,049
Actual AERC net income included in Avista Corp. net income (1)	$ 2,531	$ —

(1) AERC was acquired on July 1, 2014; therefore, none of the supplemental revenues and net income for the first quarter of 2014 were included in the actual results of Avista Corp. for that period. The amounts disclosed for the first quarter of 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 March 31, 2015, Avista Corp. has expensed $3.0 million (pre-tax) in total transaction fees. In addition to the amounts expensed, through March 31, 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, the non-regulated subsidiary of Avista Corp., 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 will have no further involvement with Ecova after such date.

The purchase price of $335.0 million, as adjusted, was divided among the security holders of Ecova, including minority shareholders and option holders, pro rata based on ownership. Approximately $16.8 million (5 percent of the purchase price) will be held in escrow for 15 months from the closing of the transaction to satisfy certain indemnification obligations under the merger agreement. An additional $1.0 million is being held in escrow pending resolution of adjustments to working capital, which is expected to be resolved in 2015.

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.

When all escrow amounts are released, the sales transaction is expected to provide cash proceeds to Avista Corp., net of debt, payment to option and minority holders, income taxes and transaction expenses, of $143.5 million and result in a net gain of $69.7 million (which was mostly recognized during the second quarter of 2014 and had some insignificant true-ups during the third and fourth quarters of 2014). These amounts have not changed from the amounts disclosed in the Company's 2014 Form 10-K. The Company expects to receive the full amount of its portion of the remaining escrow accounts; therefore, these amounts were included in the gain calculation.

Prior to the completion of the sale, Ecova was a reportable business segment. Amounts reported in discontinued operations for 2014 relate solely to the Ecova business segment. The following table presents amounts that were included in discontinued operations for the three months ended March 31, 2014 (dollars in thousands):

	2014
Revenues	$ 44,384
Income before income taxes	2,409
Income tax expense	894
Net income from discontinued operations	1,515
Net income attributable to noncontrolling interests	(492)
Net income from discontinued operations attributable to Avista Corp. shareholders	$ 1,023

Avista Corp.'s portion of the total transaction expenses was $9.1 million (including amounts which were withheld from the transaction net proceeds) and these were recognized during the second and third quarters of 2014. 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 were withheld from the net proceeds and the remainder were paid during the second and third quarter of 2014. 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.

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 economical, 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 significant 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 March 31, 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	203	1,839	10,357	97,928	253	2,730	2,079	83,313
2016	397	1,287	2,505	81,730	287	1,826	910	63,000
2017	397	—	675	31,930	286	483	—	15,420
2018	397	—	—	6,795	286	—	—	—
2019	235	—	—	4,050	158	—	—	—
Thereafter	—	—	—	—	—	—	—	—

(1) Physical transactions represent commodity transactions where Avista Utilities will take delivery of either electricity or natural gas and financial transactions represent derivative instruments with no physical delivery, such as futures, swaps or options.

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 entered into as of March 31, 2015 and December 31, 2014 (dollars in thousands):

	March 31, 2015	December 31, 2014
Number of contracts	25	18
Notional amount (in United States dollars)	$ 4,357	$ 5,474
Notional amount (in Canadian dollars)	5,498	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 Risk Management Committee also reviews the interest 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 March 31, 2015 and December 31, 2014 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
March 31, 2015	5	75,000	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

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.

As of March 31, 2015, the fair value of the outstanding interest rate swaps decreased significantly compared to December 31, 2014 (see the table below). The fair value decrease was the result of a net increase in the notional amount of outstanding swap agreements and a decline in market interest rates below the rates that were fixed in the outstanding 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 March 31, 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 March 31, 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 March 31, 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	$ 14	$ (24)	$ —	$ (10)
Interest rate contracts	Other current liabilities	—	(12,819)	677	(12,142)
Interest rate contracts	Other non-current liabilities and deferred credits	—	(100,016)	49,813	(50,203)
Commodity contracts	Current utility energy commodity derivative assets	41,898	(40,319)	—	1,579
Commodity contracts	Current utility energy commodity derivative liabilities	22,658	(40,298)	3,462	(14,178)
Commodity contracts	Other non-current liabilities and deferred credits	33,370	(57,515)	3,982	(20,163)
Total derivative instruments recorded on the balance sheet		$ 97,940	$ (250,991)	$ 57,934	$ (95,117)

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 March 31, 2015 and December 31, 2014 (in thousands):

	March 31, 2015	December 31, 2014
Energy commodity derivatives		
Cash collateral posted	$ 17,471	$ 20,565
Letters of credit outstanding	7,500	14,500
Balance sheet offsetting (cash collateral against net derivative positions)	7,444	15,510
Interest rate swaps		
Cash collateral posted	50,490	28,880
Letters of credit outstanding	17,900	10,900
Balance sheet offsetting (cash collateral against net derivative positions)	50,490	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 March 31, 2015 and December 31, 2014 (in thousands):

	March 31, 2015	December 31, 2014
Liabilities with credit-risk-related contingent features	$ 6,640	$ 12,911
Additional collateral to post	6,638	16,227

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 includes 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. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The pension and other postretirement benefit plans described below only relate to Avista Utilities and AEL&P. METALfx (not discussed below) has a salary deferral 401(k) savings plan that is a defined contribution plan and has historically not been significant to the Company.

Avista Utilities

The Company has a defined benefit pension plan covering the majority of all regular full-time employees at Avista Utilities. 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. 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 $4.0 million in cash to the pension plan for the three months ended March 31, 2015 and expects to contribute a total of $12.0 million in cash to the plan during 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 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 this plan 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. 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.

The Company has a Health Reimbursement Arrangement 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 this plan 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 pension and other postretirement benefit plans. The following table sets forth the components of net periodic benefit costs for the three months ended March 31 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2015	2014	2015	2014
Three months ended March 31:				
Service cost	$ 4,949	$ 5,018	$ 699	$ 974
Interest cost	6,672	6,706	1,331	1,353
Expected return on plan assets	(7,416)	(8,110)	(431)	(472)
Amortization of prior service cost	6	6	(279)	(43)
Net loss recognition	2,394	1,157	1,292	826
Net periodic benefit cost	$ 6,605	$ 4,777	$ 2,612	$ 2,638

AEL&P

Union Employees

Pension benefits for all union employees of AEL&P are provided through the Alaska Electrical Pension Fund Retirement Plan, a multiemployer plan to which AEL&P pays a defined contribution amount per union employee pursuant to a collective bargaining agreement with the IBEW.

AEL&P also participates in a multiemployer plan that provides substantially all union workers with health care and other welfare benefits during their working lives and after retirement. AEL&P pays a defined contribution amount per union employee pursuant to a collective bargaining agreement with the IBEW.

Non-Union Employees

AEL&P has a defined contribution money purchase pension plan covering substantially all employees of AEL&P that are not covered by a collective bargaining agreement. Contributions to the plan are made based on a percentage of each qualifying employee's compensation.

AEL&P also has a noncontributory 401(k) savings plan, which covers substantially all nonunion employees who have completed 1,000 hours of service during a 12-month period. Employees who elect to participate may contribute up to the Internal Revenue Service's maximum amount.

The pension and other postretirement plans described above for AEL&P are not significant to Avista Corp.

NOTE 7. 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 March 31, 2015 and December 31, 2014 (dollars in thousands):

	March 31, 2015	December 31, 2014
Borrowings outstanding at end of period	$ 65,000	$ 105,000
Letters of credit outstanding at end of period	$ 35,579	$ 32,579
Average interest rate on borrowings at end of period	0.94%	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 March 31, 2015 and December 31, 2014, there were no borrowings outstanding under this committed line of credit.

NOTE 8. LONG-TERM DEBT

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

Maturity Year	Description	Interest Rate	March 31, 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 and capital leases		74,198	74,149
	Settled interest rate swaps (2)		(17,439)	(17,541)
	Unamortized debt discount		(1,081)	(1,122)
	Total		1,582,378	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		(3,132)	(6,424)
	Total long-term debt and capital leases		$ 1,495,546	$ 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.

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 March 31, 2015 and December 31, 2014 were as follows (dollars in thousands):

	March 31, 2015	December 31, 2014
Capital lease obligation (1)	$ 69,398	$ 69,955
Capital lease asset (2)	71,007	71,007
Accumulated amortization of capital lease asset (2)	2,731	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 months ended March 31 (dollars in thousands):

	2015	2014
Interest on capital lease obligation	$ 923	$ —
Amortization of capital lease asset	910	—

AIDEA issued $100.0 million in revenue bonds in 1998 to finance its acquisition of the project and the payments by AEL&P are designed to be more than sufficient to enable the AIDEA to pay the principal and interest amount of its revenue bonds, bearing interest at rates ranging from 4.9 percent to 6.0 percent and maturing in January 2034. AEL&P will make its last bond payment to AIDEA in December 2033. The payments by AEL&P under the agreement 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 agreement. AEL&P is also obligated to operate, maintain and insure the project. AEL&P's payments for power under the agreement are approximately $10.6 million per year, while debt service on the bonds is approximately $5.9 million per year, which is included in the $10.6 million total cost of power.

In May 2015, AIDEA posted a notice on the Electronic Municipal Market Access and the Bloomberg websites indicating it is considering an offering of tax-exempt refunding bonds with the purpose of refunding all or a portion of their outstanding revenue bonds associated with the Snettisham Hydroelectric Project. The transaction is currently anticipated to price in June 2015. The size and timing of the anticipated transaction remains subject to market conditions and AIDEA reserves the right to change or modify its plans as it deems appropriate. AIDEA is under no obligation to pursue this transaction or any other new money or refunding issue and there is no guarantee any contemplated transactions will be consummated.

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 PPA (dollars in thousands):

	Remaining 2015	2016	2017	2018	2019	Thereafter	Total
Principal	$ 1,673	$ 2,350	$ 2,480	$ 2,615	$ 2,755	$ 57,525	$ 69,398
Interest	2,767	3,567	3,438	3,305	3,165	25,364	41,606
Total	$ 4,440	$ 5,917	$ 5,918	$ 5,920	$ 5,920	$ 82,889	$ 111,004

NOTE 9. 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 March 31, 2015 and December 31, 2014 (dollars in thousands):

	March 31, 2015		December 31, 2014	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 951,000	$ 1,132,109	$ 951,000	$ 1,118,972
Long-term debt (Level 3)	492,000	542,349	492,000	527,663
Snettisham capital lease obligation (Level 3)	69,398	79,928	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 134.52, 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 March 31, 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 March 31, 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
March 31, 2015					
Assets:					
Energy commodity derivatives	$ —	$ 96,319	$ —	$ (95,557)	$ 762
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	1,607	(790)	817
Foreign currency derivatives	—	14	—	(14)	—
Deferred compensation assets:					
Fixed income securities (2)	1,866	—	—	—	1,866
Equity securities (2)	6,233	—	—	—	6,233
Total	$ 8,099	$ 96,333	$ 1,607	$ (96,361)	$ 9,678
Liabilities:					
Energy commodity derivatives	$ —	$ 111,188	$ —	$ (103,001)	$ 8,187
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	790	(790)	—
Power exchange agreement	—	—	25,903	—	25,903
Power option agreement	—	—	251	—	251
Foreign currency derivatives	—	24	—	(14)	10
Interest rate swaps	—	112,835	—	(50,490)	62,345
Total	$ —	$ 224,047	$ 26,944	$ (154,295)	$ 96,696

	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 $0.8 million as of March 31, 2015 and 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 December 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 March 31, 2015 (dollars in thousands):

	Fair Value (Net) at March 31, 2015	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (25,903)	Surrogate facility pricing	O&M charges	$30.66-$55.56/MWh (1)
			Escalation factor	3% - 2015 to 2019
			Transaction volumes	396,984 - 397,116 MWhs
Power option agreement	(251)	Black-Scholes-Merton	Strike price	$37.87/MWh - 2015
				$56.46/MWh - 2019
			Delivery volumes	157,517 - 287,147 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreement	817	Internally derived weighted average cost of gas	Forward purchase prices	$2.10 - $2.34/mmBTU
			Forward sales prices	$2.22 - $3.17/mmBTU
			Purchase volumes	158,469 - 310,000 mmBTUs
			Sales volumes	279,990 - 800,000 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2014 were $42.90 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 2014 were $43.11 for Washington and $42.90 for Idaho.
(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.38 for 2015 to 0.20 in December 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 three months ended March 31 (dollars in thousands):

	Natural Gas Exchange Agreement	Power Exchange Agreement	Power Option Agreement	Total
Three months ended March 31, 2015:				
Balance as of January 1, 2015	$ (35)	$ (23,299)	$ (424)	$ (23,758)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	777	(6,381)	173	(5,431)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	75	3,777	—	3,852
Transfers to/from other categories	—	—	—	—
Ending balance as of March 31, 2015	$ 817	$ (25,903)	$ (251)	$ (25,337)
Three months ended March 31, 2014:				
Balance as of January 1, 2014	$ (1,219)	$ (14,441)	$ (775)	$ (16,435)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	1,849	2,026	347	4,222
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(3,048)	(1,209)	—	(4,257)
Transfers to/from other categories	—	—	—	—
Ending balance as of March 31, 2014	$ (2,418)	$ (13,624)	$ (428)	$ (16,470)

(1) The UTC and the IPUC issued accounting orders authorizing Avista Corp. to offset commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment defers the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. The orders provide for Avista Corp. 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 period 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 ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases.

NOTE 10. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORP. SHAREHOLDERS

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corp. shareholders for the three months ended March 31 (in thousands, except per share amounts):

	2015	2014
Numerator:		
Net income from continuing operations attributable to Avista Corp. shareholders	$ 46,449	$ 47,476
Net income from discontinued operations attributable to Avista Corp. shareholders	—	1,023
Subsidiary earnings adjustment for dilutive securities (discontinued operations)	—	(53)
Adjusted net income from discontinued operations attributable to Avista Corp. shareholders for computation of diluted earnings per common share	$ —	$ 970
Denominator:		
Weighted-average number of common shares outstanding-basic	62,318	60,122
Effect of dilutive securities:		
Performance and restricted stock awards	571	46
Weighted-average number of common shares outstanding-diluted	62,889	60,168
Earnings per common share attributable to Avista Corp. shareholders, basic:		
Earnings per common share from continuing operations	$ 0.75	$ 0.79
Earnings per common share from discontinued operations	$ —	$ 0.02
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 0.75	$ 0.81
Earnings per common share attributable to Avista Corp. shareholders, diluted:		
Earnings per common share from continuing operations	$ 0.74	$ 0.79
Earnings per common share from discontinued operations	$ —	$ 0.02
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 0.74	$ 0.81

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

NOTE 11. COMMITMENTS AND CONTINGENCIES

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

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 Federal Power Act 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 Federal Power Act. Briefs on and opposing exceptions have been filed and the Initial Decision is pending before the Commission. 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 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 November 2015. No date has been set for the remedy trail.

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 in the Clark Fork River exceed state of Idaho and federal water quality 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. In the second quarter of 2011, the Company completed preliminary feasibility assessments for several alternative abatement measures. In 2012, Avista Corp., with the approval of the Clark Fork Management Committee (created under the Clark Fork Settlement Agreement), moved forward to test one of the alternatives by constructing a spill crest modification on a single spill gate. Based on testing in 2013, the modification appears to provide significant Total Dissolved Gas reduction. Ongoing design improvements were made, 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. In 2014, the USFWS issued a revised draft bull trout recovery plan, with the stated expectation to finalize the plan in 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.

Kettle Falls Generation Station - Diesel Spill Investigation and Remediation

In December 2013, the Company's operations staff at the Kettle Falls Generation Station discovered that approximately 10,000 gallons of diesel fuel had leaked underground from the piping system used to fuel heavy equipment. Avista Corp. made all proper agency notifications and worked closely with the Washington State Department of Ecology (Ecology) during the spill response and investigation phase. The Company installed ground water monitoring wells and there is no indication that ground or surface water is threatened by the spill.

There is no indication that Ecology is considering any enforcement action and the Company initiated a voluntary cleanup action with the installation of a recovery system.

As of March 31, 2015, the Company has recorded an estimated remediation liability and the Company will continue to monitor the remediation activities and will adjust any estimated remediation liability if necessary as new information is obtained. The Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows.

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

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.

Investment Commitments

In October 2014, an indirect subsidiary of Avista Corp. entered into an agreement to fund a limited liability company in exchange for equity ownership in the limited liability company. This represents an unconditional commitment for $3.1 million, and the payments began in October 2014. As of March 31, 2015, the remaining commitment under the agreement was $2.5 million.

As of March 31, 2015, another indirect subsidiary of Avista Corp. also has an unconditional commitment to make investments in other companies for a total of $0.9 million. These investments will occur over a two-year period.

Coal Ash Management/Disposal

On December 19, 2014, the EPA issued a final rule regarding coal combustion residuals (CCRs), also termed coal combustion byproducts or coal ash. 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 final rule was published in the Federal Register on April 17, 2015. The Company continues to review the potential costs of complying with the new CCR standards. The Company cannot currently estimate the operational or financial impact of CCR regulation, but believes this rule will have an impact on Colstrip. If the Company were to incur incremental costs as a result of these regulations, it would seek recovery through customer rates.

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 12. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. The Company's management evaluates performance based on income (loss) from operations before income taxes as well as net income (loss) attributable to Avista Corp. shareholders. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. Avista Utilities' business is managed based on the total regulated utility operation; therefore, it is considered one segment. Ecova was 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 Other category, which is not a reportable segment, includes Spokane Energy, other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital. On July 1, 2014, the Company completed its acquisition of AERC. Based on the way AERC is managed and the financial reports that are reviewed by the Chief Operating Decision Maker, AEL&P, the primary subsidiary of AERC, is considered a separate reportable business segment and the remaining activities of AERC are included in the Other category. All goodwill associated with the AERC acquisition was assigned to the AEL&P reportable business segment.

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 March 31, 2015:						
Operating revenues	$ 424,083	$ 12,774	$ 436,857	$ 10,083	$ (450)	$ 446,490
Resource costs	206,660	2,900	209,560	—	—	209,560
Other operating expenses	70,409	2,763	73,172	10,266	(450)	82,988
Depreciation and amortization	32,997	1,303	34,300	169	—	34,469
Income (loss) from operations	84,788	5,139	89,927	(352)	—	89,575
Interest expense (2)	18,968	904	19,872	164	(22)	20,014
Income taxes	24,888	1,684	26,572	(325)	—	26,247
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	44,384	2,634	47,018	(569)	—	46,449
Capital expenditures (3)	81,212	385	81,597	412	—	82,009
For the three months ended March 31, 2014:						
Operating revenues	$ 437,574	$ —	$ 437,574	$ 9,454	$ (450)	$ 446,578
Resource costs	220,497	—	220,497	—	—	220,497
Other operating expenses	67,337	—	67,337	9,833	(450)	76,720
Depreciation and amortization	30,726	—	30,726	147	—	30,873
Income (loss) from operations	90,868	—	90,868	(526)	—	90,342
Interest expense (2)	18,546	—	18,546	397	(88)	18,855
Income taxes	27,620	—	27,620	(338)	—	27,282
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	47,996	—	47,996	(608)	88	47,476
Capital expenditures (3)	59,725	—	59,725	46	—	59,771
Total Assets:						
As of March 31, 2015:	$ 4,345,988	$ 267,590	$ 4,613,578	$ 75,451	$ —	$ 4,689,029
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 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 March 31, 2015, and the related condensed consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for the three-month periods ended March 31, 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
May 6, 2015

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

Business Segments

As of March 31, 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 the City and Borough of Juneau, Alaska. We completed our acquisition of 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 AERC and 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 months ended March 31 (dollars in thousands):

	2015	2014
Avista Utilities	$ 44,384	$ 47,996
Alaska Electric Light and Power Company	2,634	—
Ecova - Discontinued operations	—	1,111
Other	(569)	(608)
Net income attributable to Avista Corporation shareholders	$ 46,449	$ 48,499

Executive Level Summary

Overall Results

Net income attributable to Avista Corporation shareholders was $46.4 million for the three months ended March 31, 2015, a decrease from $48.5 million for the three months ended March 31, 2014. Avista Utilities' earnings decreased primarily due to weather that was significantly warmer than normal and warmer than the prior year, which reduced heating loads. The decrease in heating loads was offset by the new decoupling mechanism in Washington (implemented January 1, 2015), a general rate increase in Washington, lower net power supply costs and a decrease in the provision for earnings sharing in Idaho. Absent the impacts of mild winter weather, we would have experienced a larger increase in gross margin. 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. The decrease in consolidated earnings was also due in part to the disposition of Ecova on June 30, 2014, offset by earnings at AEL&P.

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. Avista Utilities' cash-basis capital expenditures (per the Condensed Consolidated Statement of Cash Flows) were $81.2 million and its accrual-basis capital expenditures were $65.7 million for the three months ended March 31, 2015. We expect Avista Utilities' capital expenditures to be about $375.0 million in 2015 and $350.0 million for each of 2016 and 2017. AEL&P's capital expenditures were $0.4 million for the three months ended March 31, 2015. We expect to spend approximately $15.0 million annually for the period 2015 to 2017 related to capital expenditures at AEL&P. 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 $4.7 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 the recording of $52.7 million in goodwill during 2014.

The completion of this transaction makes the financial results for 2015 and 2014 incomparable as 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.

The purchase price of $335.0 million, as adjusted, was divided among the security holders of Ecova, including minority shareholders and option holders, pro rata based on ownership. Approximately $16.8 million (5 percent of the purchase price) will be 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 will be held in escrow pending resolution of adjustments to working capital, which is expected to be completed in 2015.

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.

When all remaining escrow amounts are released, the sales transaction is expected to provide cash proceeds to Avista Corp., net of debt, payment to option and minority holders, income taxes and transaction expenses, of $143.5 million and result in a net gain of $69.7 million. The Company expects to receive the full amount of its portion of the escrow accounts; therefore, these amounts are included in the gain calculation. The net gain was recognized in 2014.

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 as the first half of 2014 contains the financial results of Ecova (in discontinued operations) and 2015 does not have any 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 commencing on January 2, 2015 and expiring on March 31, 2015 for the repurchase of up to 800,000 shares of the Company's outstanding common stock. Through March 31, 2015, 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.

Liquidity and Capital Resources

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of April 2019. We have the option to request an extension for an additional one or two years beyond April 2019, provided, 1) there are no default events prior to the requested extension, and 2) the remaining term of agreement, including the requested extension period, does not exceed five years. As of March 31, 2015, there were $65.0 million of cash borrowings and $35.6 million in letters of credit outstanding leaving $299.4 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 March 31, 2015, we were in compliance with this covenant with a ratio of 51.7 percent.

AEL&P has a committed line of credit in the amount of $25.0 million with an expiration date of November 2019. As of March 31, 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 March 31, 2015, AEL&P was in compliance with this covenant with a ratio of 58.4 percent.

For 2015, we expect to issue up to $125.0 million of long-term debt in order to maintain an appropriate capital structure and to fund planned capital expenditures.

In the three months ended March 31, 2015, we issued $0.4 million (net of issuance costs) of common stock under the employee benefit plans. We do not expect to issue any shares in 2015, other than small amounts under these plans.

After considering the expected issuances of long-term debt and common stock during 2015, we expect net cash flows from operating activities, together with cash available under our $400.0 million committed line of credit agreement and the $25.0 million AEL&P committed line of credit, 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 $18.3 million as of March 31, 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 will result 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, is 2.5 percent for electric customers and 5.6 percent for natural gas customers effective January 1, 2015.

Power Supply 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 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. This could be due to changes in weather, 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 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 has been filed with the UTC for its consideration. 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 purchase of power 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 power supply costs would be updated with the most current information two months prior to new retail rates going into effect from this case. The updated 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 results 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.

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.

As part of the settlement, we agreed not to file a general rate case in 2014, and would 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.

In addition to the general rate cases above, in April 2015, we filed a 60 day notice with the IPUC announcing our intention to file electric and natural gas general rate cases. We plan to file electric and natural gas general rate cases during the second quarter of 2015.

Oregon General Rate Cases

2013 General Rate Case

In January 2014, the OPUC approved a settlement agreement to 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 provides 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. 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 $3.8 million as of March 31, 2015 and a liability of $3.9 million as of December 31, 2014.

The following PGAs went into effect in our various jurisdictions during 2013 and 2014 (PGAs will be filed in 2015 with a proposed effective date of November 1, 2015).

Jurisdiction	PGA Effective Date	Percentage Increase / (Decrease) in Billed Rates
Washington	November 1, 2013	9.2%
	November 1, 2014	1.2%
Idaho	October 1, 2013	7.5%
	November 1, 2014	(2.1)%
Oregon	January 1, 2013	(0.8)%
	November 1, 2013	(7.9)%
	November 1, 2014	8.3%

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 $18.3 million as of March 31, 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.

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.

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 $2.9 million as of March 31, 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 Generally Accepted Accounting Principles (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. 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 March 31, 2015 compared to the three months ended March 31, 2014

Utility revenues decreased $0.7 million, after elimination of intracompany revenues of $17.8 million for the first quarter of 2015 and $34.9 million for the first quarter of 2014. Avista Utilities' portion of utility revenues decreased $13.5 million for the first quarter of 2015 and AEL&P had electric revenues of $12.8 million. Including intracompany revenues, Avista Utilities' electric revenues decreased $7.5 million and natural gas revenues decreased $23.0 million. Avista Utilities' retail electric revenues decreased $9.7 million primarily due to warmer weather partially offset by the Washington general rate increase and the decoupling deferral of $3.9 million. Wholesale electric revenues decreased $3.0 million primarily due to a decrease in sales prices partially offset by an increase in sales volumes, while sales of fuel decreased $0.8 million. In the first quarter of 2014, we recorded a provision for earnings sharing of $1.9 million for Idaho electric customers, representing an adjustment to our 2013 estimate. Retail natural gas revenues decreased $15.4 million due to a decrease in volumes caused by warmer weather during the first quarter of 2015, partially offset by higher rates (from PGAs and general rate increases) and the decoupling deferral of $2.7 million. Wholesale natural gas revenues decreased $9.4 million due to a decrease in prices, partially offset by an increase in volumes.

Utility resource costs decreased $10.9 million, after elimination of intracompany resource costs of $17.8 million for the first quarter of 2015 and $34.9 million for first quarter of 2014. Avista Utilities' portion of resource costs decreased $13.8 million and AEL&P had electric resource costs of $2.9 million. Including intracompany resource costs, Avista Utilities' electric resource costs decreased $11.0 million and natural gas resource costs decreased $19.9 million. The decrease in Avista Utilities' electric resource costs was primarily due to a decrease in purchased power, fuel costs and the decoupling deferral in Washington, 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.

Utility other operating expenses increased $5.8 million and was partially the result of AEL&P being included in the first quarter of 2015, which added $2.8 million to other operating expenses. Avista Utilities' other operating expenses increased due to an increase in pension and other postretirement benefits and administrative and general wages, partially offset by decreased generation operating and electric distribution maintenance expenses.

Utility depreciation and amortization increased $3.6 million driven by additions to utility plant and the inclusion of $1.3 million related to AEL&P for the first quarter of 2015.

Utility taxes other than income taxes increased $1.8 million primarily due to increased production, distribution and transmission property taxes. Also, the current quarter included $0.7 million related to AEL&P.

Interest expense increased $1.2 million primarily due to the acquisition of AEL&P, which added $0.9 million for the current quarter. Also, there was more long-term debt outstanding during the first quarter of 2015 compared to the first quarter of 2014.

Income taxes decreased $1.0 million and our effective tax rate was 36.1 percent for the first quarter of 2015 compared to 36.5 percent for the first quarter of 2014. The decrease in expense was primarily due to a decrease in income before income taxes.

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 March 31, 2015 compared to the three months ended March 31, 2014

Net income for Avista Utilities was $44.4 million for the first quarter of 2015, a decrease from $48.0 million for the first quarter of 2014. Avista Utilities' income from operations was $84.8 million for the first quarter of 2015, a decrease from $90.9 million for the first quarter of 2014. The decrease in net income and income from operations was primarily due to significantly warmer weather. 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 three months ended March 31 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2015	2014	2015	2014	2015	2014	2015	2014
Operating revenues	$ 266,894	$ 274,436	$ 174,983	$ 198,021	$ (17,794)	$ (34,883)	$ 424,083	$ 437,574
Resource costs	110,845	121,880	113,609	133,500	(17,794)	(34,883)	206,660	220,497
Gross margin	$ 156,049	$ 152,556	$ 61,374	$ 64,521	$ —	$ —	$ 217,423	$ 217,077

Avista Utilities' operating revenues decreased $13.5 million and resource costs decreased $13.8 million, which resulted in an increase of $0.3 million in gross margin. The gross margin on electric sales increased $3.5 million and the gross margin on natural gas sales decreased $3.2 million. The increase in electric gross margin was primarily due to a general rate increase in Washington, lower net power supply costs and a $1.9 million decrease in the provision for earnings sharing in Idaho. As such, we expected a much larger increase in gross margin. However, we experienced weather that was significantly warmer than the prior year and normal, which decreased heating loads. The decrease in heating loads was partially offset by decoupling in Washington, which had a positive effect on electric revenues and gross margin of $3.9 million. For the first quarter of 2015, we recognized a pre-tax benefit of $5.7 million under the ERM in Washington compared to a benefit of $1.3 million for the first quarter of 2014. This change represents a decrease in net power supply costs primarily due to increased hydroelectric generation, as well as lower natural gas fuel and purchased power prices in 2015. The decrease in natural gas gross margin was primarily due to lower heating loads from significantly warmer weather, partially offset by general rate increases. The decrease in heating loads was partially offset by decoupling in Washington, which had a positive effect on natural gas revenues and gross margin of $2.7 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 three months ended March 31 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2015	2014	2015	2014
Residential	$ 96,113	$ 106,803	1,024	1,165
Commercial	73,977	73,916	759	787
Industrial	27,097	25,840	441	444
Public street and highway lighting	1,561	1,891	5	6
Total retail	198,748	208,450	2,229	2,402
Wholesale	34,310	37,290	1,077	976
Sales of fuel	23,346	24,150	—	—
Other	6,622	6,413	—	—
Decoupling	3,868	—	—	—
Provision for earnings sharing	—	(1,867)	—	—
Total	$ 266,894	$ 274,436	3,306	3,378

Retail electric revenues decreased $9.7 million due to a decrease in total MWhs sold (decreased revenues $15.6 million), partially offset by an increase in revenue per MWh (increased revenues $5.9 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 the prior year. Compared to the first quarter of 2014, residential electric use per customer decreased 16 percent and commercial use per customer decreased 9 percent. Heating degree days at Spokane were 15 percent below normal and 19 percent below the first quarter of 2014.

Wholesale electric revenues decreased $3.0 million due to a decrease in sales prices (decreased revenues $6.2 million), partially offset by an increase in sales volumes (increased revenues $3.2 million). The fluctuation in volumes and prices was primarily the result of decreased retail loads from warmer weather and our optimization activities during the quarter.

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 decreased $0.8 million due to a decrease 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 first quarter of 2015, $10.7 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For the first quarter of 2014, $17.1 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. Due primarily to significantly warmer than normal weather during the first quarter of 2015, we recorded an electric decoupling deferral of $3.9 million.

In Washington and Idaho, we have earnings sharing mechanisms with our customers, such that if Avista Corp. 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. The Washington earnings sharing mechanism was implemented in 2015 and is based on a 7.32 percent overall rate of return. The decoupling rebate or surcharge balance also factors into the Washington earnings sharing mechanism. In the first quarter of 2015, our earnings were below these threshold amounts and we did not record a provision for earnings sharing. In the first quarter of 2014, we revised our allocation of 2013 costs between Idaho and Washington for regulatory purposes, which resulted in an additional provision for earnings sharing to Idaho electric customers of $1.9 million.

The following table presents our utility natural gas operating revenues and therms delivered for the three months ended March 31 (dollars and therms in thousands):

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2015	2014	2015	2014
Residential	$ 77,162	$ 86,819	71,140	86,161
Commercial	38,214	43,925	41,199	50,658
Interruptible	890	848	1,415	1,524
Industrial	1,289	1,396	1,656	1,851
Total retail	117,555	132,988	115,410	140,194
Wholesale	51,108	60,485	190,789	126,042
Transportation	2,148	2,154	45,053	47,010
Other	1,499	2,396	162	219
Decoupling	2,673	—	—	—
Provision for earnings sharing	—	(2)	—	—
Total	$ 174,983	$ 198,021	351,414	313,465

Retail natural gas revenues decreased $15.4 million due to a decrease in volumes (decreased revenues $25.2 million), partially offset by higher retail rates (increased revenues $9.8 million). Higher retail rates were due to PGAs and general rate cases. We sold less retail natural gas in the first quarter of 2015 as compared to the first quarter of 2014 due to warmer weather. Compared to the first quarter of 2014, residential natural gas use per customer decreased 20 percent and commercial use per customer decreased 21 percent. Heating degree days at Spokane were 15 percent below historical average for the first quarter of 2015, and 19 percent below the first quarter of 2014. Heating degree days at Medford were 19 percent below historical average for the first quarter of 2015 and 9 percent below the first quarter of 2014.

Wholesale natural gas revenues decreased $9.4 million due to a decrease in prices (decreased revenues $26.7 million), partially offset by an increase in volumes (increased revenues $17.3 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 quarter of 2015, $7.1 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In the first quarter of 2014, $17.8 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. Due primarily to significantly warmer than normal weather during the first quarter of 2015, we recorded a natural gas decoupling deferral of $2.7 million.

The following table presents our average number of electric and natural gas retail customers for the three months ended March 31:

	Electric Customers		Natural Gas Customers	
	2015	2014	2015	2014
Residential	326,551	323,911	295,141	291,910
Commercial	41,339	40,689	34,245	34,144
Interruptible	—	—	33	35
Industrial	1,337	1,385	262	258
Public street and highway lighting	547	531	—	—
Total retail customers	369,774	366,516	329,681	326,347

The following table presents our utility resource costs for the three months ended March 31 (dollars in thousands):

	2015	2014
Electric resource costs:		
Power purchased	$ 52,160	$ 61,665
Power cost amortizations, net	8,250	(5,677)
Fuel for generation	24,218	34,967
Other fuel costs	20,993	20,210
Other regulatory amortizations, net	4,825	5,406
Other electric resource costs	399	5,309
Total electric resource costs	110,845	121,880
Natural gas resource costs:		
Natural gas purchased	111,442	132,868
Natural gas cost amortizations, net	(224)	(2,364)
Other regulatory amortizations, net	2,391	2,996
Total natural gas resource costs	113,609	133,500
Intracompany resource costs	(17,794)	(34,883)
Total resource costs	$ 206,660	$ 220,497

Power purchased decreased $9.5 million due to a decrease in the volume of power purchases (decreased costs $11.3 million), partially offset by a slight increase in wholesale prices (increased costs $1.8 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 increased hydroelectric generation and a decrease in retail loads.

Power costs deferrals and amortizations (net) increased electric resource costs by $8.2 million for the three months ended March 31, 2015 compared to a decrease of $5.7 million for the three months ended March 31, 2014. During the three months ended March 31, 2015, we surcharged customers $2.2 million of previously deferred power costs in Idaho through the PCA. We also refunded to Washington customers $2.3 million through an ERM rebate and $1.3 million through a REC rebate. During the three months ended March 31, 2015, actual power supply costs were below the amount included in base retail rates and we deferred $6.8 million in Washington (including $0.4 million for RECs in Washington for probable future benefit to customers) and $2.9 million in Idaho for probable future benefit to customers.

Fuel for generation decreased $10.7 million primarily due to a decrease in natural gas generation (due in part to increased hydroelectric generation and a decrease in total MWhs sold) and a decrease in natural gas fuel prices.

Other fuel costs increased $0.8 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 $4.9 million primarily due to 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 $21.4 million due to a decrease in the price of natural gas (decreased costs $36.0 million), partially offset by an increase in total therms purchased (increased costs $14.6 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 and storage capacity 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

As noted above, AEL&P was acquired on July 1, 2014; therefore, only the three months ended March 31, 2015 are shown.

Three months ended March 31, 2015

Net income for AEL&P was $2.6 million for the three months ended March 31, 2015.

The following table presents AEL&P's operating revenues, resource costs and resulting gross margin for the three months ended March 31, 2015 (dollars in thousands):

	Electric
Operating revenues	$ 12,774
Resource costs	2,900
Gross margin	$ 9,874

The following table presents AEL&P's utility electric operating revenues and megawatt-hour (MWh) sales for the three months ended March 31, 2015 (dollars and MWhs in thousands):

	Electric Operating Revenues	Electric Energy MWh sales
Residential	$ 5,744	44
Commercial and government	6,890	67
Public street and highway lighting	8	1
Total retail	12,642	112
Other	132	—
Total	$ 12,774	112

AEL&P's operating revenues were $12.8 million and its resource costs were $2.9 million, which resulted in gross margin of $9.9 million, all related to electric sales. Retail revenues for the current period were derived from weather that was warmer than normal with heating degree days that were 12 percent below normal. AEL&P's revenues are not as sensitive to weather fluctuations as Avista Utilities because it has a more stable load profile as there is not a large population of customers in its service territory with electric heating and cooling. 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 March 31, 2015:

	Electric Customers
Residential	14,123
Commercial and government	2,156
Public street and highway lighting	213
Total retail customers	16,492

The following table presents AEL&P's utility resource costs for the three months ended March 31, 2015 (dollars in thousands):

	Resource Costs
Snettisham power expenses	$ 2,555
Power cost amortizations, net	320
Fuel for generation	25
Total electric resource costs	$ 2,900

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 8 of the Notes to Condensed Consolidated Financial Statements" for further information regarding this capital lease obligation.

The cost of power adjustment is 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, all cruise ship revenue is 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 March 31, 2015 and December 31, 2014 (dollars in thousands):

	March 31, 2015	December 31, 2014
Spokane Energy (1)	$ 26,720	$ 30,404
METALfx	11,687	12,065
Steam Plant and Courtyard Office Center	7,108	7,278
Alaska companies (AERC and AJT Mining)	7,868	7,507
Avista Capital - standalone (2)	13,849	13,221
Other	8,219	9,735
Total	$ 75,451	$ 80,210

(1) The decrease in the value of Spokane Energy assets represents the continued amortization of the long-term fixed rate electric capacity contract, which expires in December 2016.

(2) The balance at March 31, 2015 includes $13.1 million in escrow amounts related to the sale of Ecova and cash of $0.7 million held at Avista Capital.

Three months ended March 31, 2015 compared to the three months ended March 31, 2014

The net loss from these operations was $0.6 million for the three months ended March 31, 2015 and March 31, 2014. The net loss for the first quarter of 2015 was primarily the result of $0.5 million (net of tax) of corporate costs, including costs associated with exploring strategic opportunities, and net losses on investments of $0.4 million. This was offset by METALfx net income of $0.3 million for the first quarter of 2015, which compares to net income of $0.1 million for the first quarter of 2014.

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 2014 Form 10-K and have not changed materially from that discussion.

Liquidity and Capital Resources

Overall Liquidity

Historically, 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, improvement and maintenance 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 Avista Corp.'s $400.0 million committed line of credit.

As of March 31, 2015, we had $299.4 million of available liquidity under the Avista Corp. committed line of credit. With our $400.0 million credit facility that expires in April 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 three months ended March 31, 2015, positive cash flows from operating activities were $146.8 million. Cash requirements included utility capital expenditures of $81.6 million, dividends of $20.7 million, the repayment of short-term borrowings of $40.0 million, contributions to our pension plan of $4.0 million, an increase in our collateral postings of $18.5 million and the repurchase of common stock of $2.9 million.

Operating Activities

Net cash provided by operating activities was $146.8 million for the three months ended March 31, 2015 compared to $156.9 million for the three months ended March 31, 2014. Net cash provided by fluctuations in certain current assets and liabilities was $50.4 million for the first quarter of 2015, compared to net cash provided of $75.2 million for the first quarter of 2014. The net cash provided by certain current assets and liabilities during the first quarter of 2015 primarily reflects positive cash flows related to fluctuations in income taxes receivable and income taxes payable, materials and supplies, 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 collateral posted for derivative instruments (primarily due to a decrease in the fair value of outstanding interest rate swaps, which required additional collateral).

The net cash provided by certain current assets and liabilities during the first quarter of 2014 primarily reflects positive cash flows related to fluctuations in collateral posted for derivative instruments, income taxes receivable and income taxes payable and accounts receivable. These positive cash flows were partially offset by net cash outflows related to accounts payable and other current assets.

Net deferrals of power and natural gas costs increased operating cash flows by $8.2 million for the three months ended March 31, 2015 compared to a decrease in operating cash flows of $8.0 million for the three months ended March 31, 2014. The benefit for deferred income taxes was $0.1 million for the three months ended March 31, 2015 compared to a provision of $1.5 million for the three months ended March 31, 2014. Contributions to our defined benefit pension plan were $4.0 million for the first quarter of 2015 and $11.0 million for the first quarter of 2014. Net cash received for income taxes was $37.1 million for the first quarter of 2015, compared to net cash received of $0.1 million for the first quarter of 2014.

Investing Activities

Net cash used in investing activities was $80.2 million for the three months ended March 31, 2015, compared to net cash used of $60.7 million for the three months ended March 31, 2014. During the first quarter of 2015, we paid $81.6 million for utility capital expenditures, compared to $59.7 million for first quarter of 2014. During the first quarter of 2014, a significant portion of Ecova's funds were held as securities available for sale and they had sales and maturities of $11.4 million. In addition, during the first quarter of 2014 the fluctuation in the balance of funds held for customers resulted in a decrease to cash of $9.3 million.

Financing Activities

Net cash used in financing activities was $66.7 million for the three months ended March 31, 2015 compared to net cash used of $88.6 million for the three months ended March 31, 2014. During the first quarter of 2015, short-term borrowings on Avista Corp.'s committed line of credit decreased $40.0 million, compared to a decrease of $60.0 million in the first quarter of 2014. Cash dividends paid to Avista Corp. shareholders increased to $20.7 million (or $0.33 per share) for the first quarter of 2015 from $19.2 million (or $0.3175 per share) for the first quarter of 2014. During the three months ended March 31, 2015, we issued $0.4 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 three months ended March 31, 2014, we issued $0.6 million of common stock.

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 March 31, 2015, we had cash deposited as collateral in the amount of $17.5 million and letters of credit of $7.5 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 March 31, 2015, we would potentially be required to post additional collateral of up to $15.5 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 $23.3 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 March 31, 2015, we had interest rate swap agreements outstanding with a notional amount totaling $500.0 million and we had deposited cash in the amount of $50.5 million and letters of credit of $17.9 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 March 31, 2015, we would be required to post additional collateral of $31.7 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 March 31, 2015 and December 31, 2014 (dollars in thousands):

	March 31, 2015		December 31, 2014	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt and capital leases	$ 3,132	0.1%	$ 6,424	0.2%
Current portion of nonrecourse long-term debt (Spokane Energy)	—	—%	1,431	0.1%
Short-term borrowings	65,000	2.1%	105,000	3.4%
Long-term debt to affiliated trusts	51,547	1.6%	51,547	1.6%
Long-term debt and capital leases	1,495,546	47.9%	1,492,062	47.5%
Total debt	1,615,225	51.7%	1,656,464	52.8%
Total Avista Corporation shareholders' equity	1,507,175	48.3%	1,483,671	47.2%
Total	$ 3,122,400	100.0%	$ 3,140,135	100.0%

Our shareholders' equity increased $23.5 million during the first quarter 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 the liquidity and capital resource transactions which occurred during the first quarter of 2015 and our anticipated needs for the remainder of 2015.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under our committed line of credit were as follows as of and for the three months ended March 31 (dollars in thousands):

	2015	2014
Borrowings outstanding at end of period	$ 65,000	$ 111,000
Letters of credit outstanding at end of period	$ 35,579	$ 9,614
Maximum borrowings outstanding during the period	$ 137,500	$ 171,000
Average borrowings outstanding during the period	$ 97,600	$ 90,806
Average interest rate on borrowings during the period	0.98%	0.96%
Average interest rate on borrowings at end of period	0.94%	0.93%

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 March 31, 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

We expect Avista Utilities' capital expenditures to be about $375.0 million in 2015 and $350.0 million for each of 2016 and 2017. In addition, we expect to spend approximately $15.0 million annually for the period 2015 to 2017 related to capital expenditures at AEL&P. Most of the capital expenditures at Avista Utilities are for upgrading and maintenance of 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 March 31, 2015, we had $35.6 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 three months ended March 31, 2015 we contributed $4.0 million to the pension plan. 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.

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 May 6, 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 February 6, 2015, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.33 per share on the Company's common stock, which is a 4 percent increase from the previous quarterly dividend of $0.3175 per share.

Contractual Obligations

Our future contractual obligations have not materially changed during the three months ended March 31, 2015 except that on March 30, 2015, Avista Corp. provided a cancellation notice to one of its information technology service providers. We are still determining the final end date of the agreement, but we expect the agreement to end before the end of 2015. As a result, we expect our contractual obligations in 2016 and 2017 for Avista Utilities to decrease by approximately $8 million per year. The expenditures associated with this information technology agreement were primarily recorded to other operating expenses in the Condensed Consolidated Statements of Income. Even though our contractual obligations are expected to decrease by approximately $8 million per year, we do not expect a significant reduction in our overall other operating expenses. See the 2014 Form 10-K for all 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, March 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. Foreclosure rates are below the U.S rate in all three areas, and key leading indicators, initial unemployment claims and residential building permits, continue to signal modest growth over the next 12 months. Therefore, in 2015, we expect economic growth in our service area to be about the same as 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 March 2015 and March 2014. In Spokane, Washington employment growth was 2.7 percent with gains in all major employment sectors. Employment increased by 6.0 percent in Coeur d'Alene, Idaho, reflecting gains in all major employment sectors, except mining and logging and information. In Medford, Oregon, employment growth was 3.5 percent, with gains in all major employment sectors, except information. U.S. nonfarm employment grew by 2.3 percent in the same 12-month period.

Non-seasonally adjusted unemployment rates went down in March 2015 from the year earlier in Spokane, Coeur d'Alene, and Medford. In Spokane the rate was 8.2 percent in March 2014 and declined to 7.1 percent in March 2015; in Coeur d'Alene the rate went from 7.2 percent to 5.5 percent; and in Medford the rate declined from 9.9 percent to 7.4 percent. The U.S. rate declined from 6.8 percent to 5.6 percent in the same period.

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

Our AEL&P service area is centered in the City and Borough of Juneau, Alaska (Juneau). 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 declined 0.3 percent between third quarter 2013 and third quarter 2014. A significant portion of this decline was due to a contraction in government employment, which is Juneau's largest single sector. Government (including active duty military personnel) accounts for approximately 37 percent of total employment. Employment declines also occurred in trade, transportation, and utilities; information; financial activities; and other services. Employment gains did occur in natural resources and mining; construction; professional and business services; education and health services; and leisure and hospitality. Between March 2015 and March 2014 the non-seasonally adjusted unemployment rate declined from 5.7 percent to 5.5 percent.

The Juneau foreclosure rate is below the U.S. rate. The March 2015 rate was 0.05 percent compared to 0.09 percent for the U.S.

Environmental Issues and Contingencies

Our environmental issues and contingencies disclosures have not materially changed except for the following during the three months ended March 31, 2015. See the 2014 Form 10-K for all other environmental issues and contingencies.

Climate Change - State Legislation and State Regulatory Activities

On April 29, 2014, Washington State Governor Jay Inslee issued Executive Order 14-04, "Washington Carbon Pollution Reduction and Clean Energy Action." The order created a "Climate Emissions Reduction Task Force" to provide recommendations to the Governor on design and implementation of a market-based carbon pollution program to inform possible legislative proposals in 2015. The order also called on the program to "establish a cap on carbon pollution emissions, with binding requirements to meet our statutory emission limits." The order also states that the Governor's Legislative Affairs and Policy Office "will seek negotiated agreements with key utilities and others to reduce and eliminate over time the use of electrical power produced from coal." The Task Force issued a report summarizing its efforts, which included a range of potential carbon-reducing proposals. Subsequently, in January 2015, at Washington Governor Jay Inslee's request, the Carbon Pollution Accountability Act was introduced as a bill in the Washington legislature. The proposed bill includes a proposed cap and trade system for carbon emissions from a wide range of sources, including fossil-fired electrical generation, "imported" power generated by fossil fuels, natural gas sales and use, and certain uses of biomass for electrical generation. Additional legislative proposals related to climate change and carbon emissions may be forthcoming. While we cannot predict the 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 2013, the Oregon Legislature enacted Senate Bill 306, directing the Legislative Revenue Office to examine the feasibility of imposing a carbon tax on a statewide basis. A report prepared by Portland State University's Northwest Economic Research Center was submitted to the Legislature in December 2014 and it analyzed, broadly, potential economic impacts of enacting a carbon tax. Legislation was introduced during the 2015 legislative session to authorize the imposition of a carbon tax. Any future proposal to tax natural gas as a fuel for electricity generation and to tax the carbon content of electricity produced in, but exported from, Oregon could have implications for the cost of operating Coyote Springs II. We will monitor further developments in Oregon, but we cannot estimate any impact at this time.

Other

For other environmental issues and other contingencies see "Note 11 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 three months ended March 31, 2015. Please refer to the 2014 Form 10-K. The following table presents energy commodity derivative fair values as a net asset or (liability) as of March 31, 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	$ (3,501)	$ (18,601)	$ (2,599)	$ (37,575)	$ (57)	$ 26,205	$ 1,397	$ 26,948
2016	(6,914)	(7,827)	(3,824)	(26,692)	(39)	17,266	(445)	16,660
2017	(6,035)	—	(657)	(5,297)	(76)	1,914	—	1,497
2018	(5,982)	—	—	(1,628)	(70)	—	—	—
2019	(3,404)	—	—	(813)	(56)	—	—	—
Thereafter	—	—	—	—	—	—	—	—

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 where we will take or make delivery of either electricity or natural gas and financial transactions represent derivative instruments with no physical delivery, 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 eventually be collected through retail rates from customers.

Credit Risk

Our credit risk has not materially changed during the three months ended March 31, 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 March 31, 2015 and December 31, 2014 (dollars in thousands):

	March 31, 2015	December 31, 2014
Number of agreements	26	22
Notional amount	$ 500,000	$ 420,000
Mandatory cash settlement dates	2015 to 2019	2015 to 2018
Short-term derivative assets (1)	$ —	$ 460
Short-term derivative liability (1) (2)	(12,142)	(7,325)
Long-term derivative liability (1) (2)	(50,203)	(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 March 31, 2015 and December 31, 2014 reflect the offsetting of $50.5 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 three months ended March 31, 2015. See the 2014 Form 10-K.

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

	March 31, 2015	December 31, 2014
Number of contracts	25	18
Notional amount (in United States dollars)	$ 4,357	$ 5,474
Notional amount (in Canadian dollars)	5,498	6,198
Other current derivative liability	(10)	(20)

Further information for derivatives and fair values is disclosed at “Note 5 of the Notes to Condensed Consolidated Financial Statements” and “Note 9 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) 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. Under the supervision and with the participation of the Company’s management, including the Company’s principal executive officer and principal financial officer, the Company 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. Disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives. Based upon the Company's 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 March 31, 2015.

During February 2015, we implemented new customer information and work management systems. This implementation has resulted in certain changes to business processes and internal controls impacting financial reporting. There are inherent risks associated with replacing and changing these types of systems, such as delayed and/or inaccurate customer bills, potential disruption of our business, and substantial unplanned costs. Consistent with our expectations, we have experienced delays in collections of customer receivables during the transition to the new systems. We have taken steps to monitor and maintain appropriate internal control over financial reporting during this period of system change and will continue to evaluate the operating effectiveness of related controls during subsequent periods.

Other than these system implementations, there have been no changes in the Company's internal control over financial reporting that occurred during the first 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 11 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) Issuer Purchases of Equity Securities

On December 16, 2014, Avista Corp. announced that its 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). The number of shares repurchased through the first quarter 2015 program were in addition to the number of shares repurchased during 2014 under a separate stock repurchase program, which expired on December 31, 2014. The parameters of the first quarter 2015 program were consistent with the parameters of the 2014 program. Through March 31, 2015, we repurchased 89,400 shares under the first quarter 2015 program 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.

The following table provides information about share repurchases that we made through our first quarter 2015 share repurchase program during the three months ended March 31, 2015 (in thousands, except per share amounts):

	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Program	(d) Maximum Number of Shares that May Yet Be Purchased Under the Program
January 1 to January 31, 2015	—	$ —	—	800
February 1 to February 28, 2015	—	—	—	800
March 1 to March 31, 2015	89	32.66	89	711
Total	89	$ 32.66	89	711 (1)

(1) The first quarter 2015 share repurchase program expired on March 31, 2015; therefore, no further shares can be repurchased under this program after that date.

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 March 31, 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: May 6, 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)

	Three months ended	Years Ended December 31				
	March 31, 2015	2014	2013	2012	2011	2010
Fixed charges, as defined:						
Interest charges	$ 20,069	$ 74,025	$ 73,772	$ 71,843	$ 69,536	$ 71,734
Amortization of debt expense and premium - net	867	3,635	3,813	3,803	4,617	4,414
Interest portion of rentals	306	1,187	1,146	1,294	1,139	1,248
Total fixed charges	$ 21,242	$ 78,847	$ 78,731	$ 76,940	$ 75,292	$ 77,396
Earnings, as defined:						
Pre-tax income from continuing operations	$ 72,709	$ 192,106	$ 162,347	$ 116,567	$ 139,438	$ 130,536
Add (deduct):						
Capitalized interest	(917)	(3,924)	(3,676)	(2,401)	(2,942)	(298)
Total fixed charges above	21,242	78,847	78,731	76,940	75,292	77,396
Total earnings	$ 93,034	$ 267,029	$ 237,402	$ 191,106	$ 211,788	$ 207,634
Ratio of earnings to fixed charges	4.38	3.39	3.02	2.48	2.81	2.68

Exhibit 15

May 6, 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 March 31, 2015 and 2014, as indicated in our report dated May 6, 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 March 31, 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: May 6, 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: May 6, 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 March 31, 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: May 6, 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