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

Form 10-Q

(Mark One)

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

FOR THE QUARTERLY PERIOD ENDED June 30, 2014 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 July 31, 2014, 64,432,985 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;
- 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;
- volatility and illiquidity in wholesale energy markets, including the availability of willing buyers and sellers, and prices of purchased energy and demand for energy sales including related energy commodity derivative instruments that we rely upon to hedge our wholesale energy risks;
- the outcome of pending legal proceedings arising out of the “western energy crisis” of 2000 and 2001;

- 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, 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;
- information that was covered under management's representations and warranties related to the Ecova sale could be inaccurate or incomplete at the time of sale, or new information could be identified subsequent to the sale date, which could impact our ability to fully collect the indemnification escrow amounts; and
- the majority of hydroelectric power generation for our Alaska operations is provided by a single facility that is subject to a long-term power purchase agreement and any issues that negatively affect this facility's ability to generate or transmit power, 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 Web site address is www.avistacorp.com. We make annual, quarterly and current reports available at our Web site as soon as practicable after electronically filing these reports with the Securities and Exchange Commission. Information contained on our Web site is not part of this report.

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CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

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

	2014	2013
Operating Revenues:		
Utility revenues	$ 303,105	$ 297,719
Non-utility revenues	9,475	9,769
Total operating revenues	312,580	307,488
Operating Expenses:		
Utility operating expenses:		
Resource costs	128,922	126,511
Other operating expenses	67,349	65,784
Depreciation and amortization	31,180	29,025
Taxes other than income taxes	21,367	21,608
Non-utility operating expenses:		
Other operating expenses	880	9,415
Depreciation and amortization	151	175
Total operating expenses	249,849	252,518
Income from continuing operations	62,731	54,970
Interest expense	18,547	19,438
Interest expense to affiliated trusts	112	117
Capitalized interest	(834)	(942)
Other income-net	(3,055)	(2,192)
Income from continuing operations before income taxes	47,961	38,549
Income tax expense	16,691	14,310
Net income from continuing operations	31,270	24,239
Net income on discontinued operations (Note 5)	69,312	1,491
Net income	100,582	25,730
Net loss (income) attributable to noncontrolling interests	289	(73)
Net income attributable to Avista Corp. shareholders	$ 100,871	$ 25,657

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (continued)

Avista Corporation

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

	2014	2013
Amounts attributable to Avista Corp. shareholders:		
Net income from continuing operations attributable to Avista Corp. shareholders	$ 31,254	$ 24,212
Net income from discontinued operations attributable to Avista Corp. shareholders	69,617	1,445
Net income attributable to Avista Corp. shareholders	$ 100,871	$ 25,657
Weighted-average common shares outstanding (thousands), basic	60,184	59,937
Weighted-average common shares outstanding (thousands), diluted	60,463	59,962
Earnings per common share attributable to Avista Corp. shareholders, basic:		
Earnings per common share from continuing operations	$ 0.52	$ 0.40
Earnings per common share from discontinued operations	1.16	0.03
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 1.68	$ 0.43
Earnings per common share attributable to Avista Corp. shareholders, diluted:		
Earnings per common share from continuing operations	$ 0.52	$ 0.40
Earnings per common share from discontinued operations	1.15	0.03
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 1.67	$ 0.43
Dividends declared per common share	$ 0.3175	$ 0.305

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

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

	2014	2013
Operating Revenues:		
Utility revenues	$ 740,229	$ 728,846
Non-utility revenues	18,929	19,141
Total operating revenues	759,158	747,987
Operating Expenses:		
Utility operating expenses:		
Resource costs	349,419	356,141
Other operating expenses	134,686	131,228
Depreciation and amortization	61,906	56,960
Taxes other than income taxes	49,513	47,425
Non-utility operating expenses:		
Other operating expenses	10,263	18,760
Depreciation and amortization	298	365
Total operating expenses	606,085	610,879
Income from continuing operations	153,073	137,108
Interest expense	37,291	38,686
Interest expense to affiliated trusts	223	235
Capitalized interest	(1,495)	(1,882)
Other income-net	(5,655)	(3,951)
Income from continuing operations before income taxes	122,709	104,020
Income tax expense	43,973	38,562
Net income from continuing operations	78,736	65,458
Net income from discontinued operations (Note 5)	70,827	3,373
Net income	149,563	68,831
Net income attributable to noncontrolling interests	(193)	(833)
Net income attributable to Avista Corp. shareholders	$ 149,370	$ 67,998

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (continued)

Avista Corporation

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

	2014	2013
Amounts attributable to Avista Corp. shareholders:		
Net income from continuing operations attributable to Avista Corp. shareholders	$ 78,730	$ 65,432
Net income from discontinued operations attributable to Avista Corp. shareholders	70,640	2,566
Net income attributable to Avista Corp. shareholders	$ 149,370	$ 67,998
Weighted-average common shares outstanding (thousands), basic	60,153	59,926
Weighted-average common shares outstanding (thousands), diluted	60,316	59,954
Earnings per common share attributable to Avista Corp. shareholders, basic:		
Earnings per common share from continuing operations	$ 1.31	$ 1.09
Earnings per common share from discontinued operations	1.17	0.04
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 2.48	$ 1.13
Earnings per common share attributable to Avista Corp. shareholders, diluted:		
Earnings per common share from continuing operations	$ 1.31	$ 1.09
Earnings per common share from discontinued operations	1.17	0.04
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 2.48	$ 1.13
Dividends declared per common share	$ 0.635	$ 0.61

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

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

	2014	2013
Net income	$ 100,582	$ 25,730
Other Comprehensive Income (Loss):		
Unrealized investment gains/(losses) - net of taxes of $201 and $(721), respectively	341	(1,222)
Reclassification adjustment for realized gains on investment securities included in net income from discontinued operations - net of taxes of $0 and $(6), respectively	—	(10)
Reclassification adjustment for realized losses on investment securities included in net income from discontinued operations - net of taxes of $273 and $0, respectively	462	—
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $62 and $99, respectively	112	183
Total other comprehensive income (loss)	915	(1,049)
Comprehensive income	101,497	24,681
Comprehensive loss (income) attributable to noncontrolling interests	289	(73)
Comprehensive income attributable to Avista Corporation shareholders	$ 101,786	$ 24,608

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

	2014	2013
Net income	$ 149,563	$ 68,831
Other Comprehensive Income (Loss):		
Unrealized investment gains/(losses) - net of taxes of $664 and $(760), respectively	1,126	(1,292)
Reclassification adjustment for realized gains on investment securities included in net income from discontinued operations - net of taxes of $(1) and $(7), respectively	(2)	(11)
Reclassification adjustment for realized losses on investment securities included in net income from discontinued operations - net of taxes of $273 and $0, respectively	462	—
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $121 and $198, respectively	223	367
Total other comprehensive income (loss)	1,809	(936)
Comprehensive income	151,372	67,895
Comprehensive income attributable to noncontrolling interests	(193)	(833)
Comprehensive income attributable to Avista Corporation shareholders	$ 151,179	$ 67,062

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands
(Unaudited)

	June 30, 2014	December 31, 2013
Assets:		
Current Assets:		
Cash and cash equivalents	$ 207,967	$ 82,574
Accounts and notes receivable-less allowances of $4,626 and $44,309, respectively	127,614	221,343
Utility energy commodity derivative assets	10,869	3,022
Regulatory asset for utility derivatives	—	10,829
Investments and funds held for clients	—	96,688
Materials and supplies, fuel stock and natural gas stored	49,437	44,946
Deferred income taxes	8,266	24,788
Income taxes receivable	—	7,783
Other current assets	38,114	57,706
Total current assets	442,267	549,679
Net Utility Property:		
Utility plant in service	4,385,131	4,290,464
Construction work in progress	191,611	160,323
Total	4,576,742	4,450,787
Less: Accumulated depreciation and amortization	1,294,679	1,248,362
Total net utility property	3,282,063	3,202,425
Other Non-current Assets:		
Investment in exchange power-net	12,658	13,883
Investment in affiliated trusts	11,547	11,547
Goodwill	5,246	76,257
Intangible assets-net of accumulated amortization of $0 and $36,634, respectively	—	39,576
Long-term energy contract receivable of Spokane Energy	34,541	40,619
Other property and investments-net	36,028	58,555
Total other non-current assets	100,020	240,437
Deferred Charges:		
Regulatory assets for deferred income tax	66,555	71,421
Regulatory assets for pensions and other postretirement benefits	153,426	156,984
Other regulatory assets	114,253	102,915
Non-current utility energy commodity derivative assets	275	854
Non-current regulatory asset for utility derivatives	13,304	23,258
Other deferred charges	29,967	13,950
Total deferred charges	377,780	369,382
Total assets	$ 4,202,130	$ 4,361,923

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

Dollars in thousands
(Unaudited)

	June 30, 2014	December 31, 2013
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 73,349	$ 182,088
Client fund obligations	—	99,117
Current portion of long-term debt	4,348	358
Current portion of nonrecourse long-term debt of Spokane Energy	9,812	16,407
Short-term borrowings	151,500	171,000
Utility energy commodity derivative liabilities	3,378	10,875
Income taxes payable	98,314	697
Other current liabilities	123,630	144,798
Total current liabilities	464,331	625,340
Long-term debt	1,268,530	1,272,425
Nonrecourse long-term debt of Spokane Energy	—	1,431
Long-term debt to affiliated trusts	51,547	51,547
Long-term borrowings under committed line of credit	—	46,000
Regulatory liability for utility plant retirement costs	248,129	242,850
Pensions and other postretirement benefits	103,421	122,513
Deferred income taxes	542,090	535,343
Other non-current liabilities and deferred credits	114,537	130,318
Total liabilities	2,792,585	3,027,767
Commitments and Contingencies (See Notes to Condensed Consolidated Financial Statements)		
Redeemable Noncontrolling Interests	—	15,889
Equity:		
Avista Corporation Shareholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 60,220,099 and 60,076,752 shares outstanding, respectively	885,741	896,993
Accumulated other comprehensive loss	(4,010)	(5,819)
Retained earnings	528,285	407,092
Total Avista Corporation shareholders' equity	1,410,016	1,298,266
Noncontrolling Interests	(471)	20,001
Total equity	1,409,545	1,318,267
Total liabilities and equity	$ 4,202,130	$ 4,361,923

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

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

	2014	2013
Operating Activities:		
Net income (continuing and discontinued operations)	$ 149,563	$ 68,831
Non-cash items included in net income:		
Depreciation and amortization	68,543	64,890
Provision (benefit) for deferred income taxes	24,161	(1,404)
Power and natural gas cost deferrals, net	(10,032)	(430)
Amortization of debt expense	1,889	1,895
Amortization of investment in exchange power	1,225	1,225
Stock-based compensation expense	4,838	3,080
Equity-related AFUDC	(4,237)	(2,746)
Pension and other postretirement benefit expense	11,585	21,478
Amortization of Spokane Energy contract	6,078	5,587
Write-off of Reardan wind generation capitalized costs	—	2,534
Gain on sale of Ecova	(161,100)	—
Other	8,778	3,893
Contributions to defined benefit pension plan	(21,500)	(29,340)
Changes in certain current assets and liabilities:		
Accounts and notes receivable	59,086	43,443
Materials and supplies, fuel stock and natural gas stored	(4,491)	2,133
Other current assets	12,263	(11,365)
Accounts payable	(34,025)	(27,106)
Income taxes payable	97,617	10,287
Other current liabilities	13,747	(1,090)
Net cash provided by operating activities	223,988	155,795
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(136,514)	(145,344)
Other capital expenditures	(6,122)	(1,344)
Federal grant payments received	1,729	2,297
Cash paid for acquisition	(4,697)	—
Decrease (increase) in funds held for clients	(18,931)	10,675
Purchase of securities available for sale	(12,267)	(31,949)
Sale and maturity of securities available for sale	14,612	15,130
Proceeds from sale of Ecova, net of cash sold	229,903	—
Other	(475)	(4,369)
Net cash provided by (used in) investing activities	67,238	(154,904)

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

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

	2014	2013
Financing Activities:		
Net increase (decrease) in short-term borrowings	$ (19,500)	$ 43,500
Borrowings from Ecova line of credit	—	3,000
Repayment of borrowings from Ecova line of credit	(46,000)	(5,000)
Redemption and maturity of long-term debt	(149)	(359)
Maturity of nonrecourse long-term debt of Spokane Energy	(8,026)	(7,329)
Cash received for settlement of interest rate swap agreements	—	2,901
Issuance of common stock, net of issuance costs	1,980	3,017
Cash dividends paid	(38,327)	(36,667)
Increase in client fund obligations	16,216	6,220
Payment to noncontrolling interests for sale of Ecova	(54,179)	—
Payment to option holders and redeemable noncontrolling interests for sale of Ecova	(20,871)	—
Other	3,023	(227)
Net cash provided by (used in) financing activities	(165,833)	9,056
Net increase in cash and cash equivalents	125,393	9,947
Cash and cash equivalents at beginning of period	82,574	75,464
Cash and cash equivalents at end of period	$ 207,967	$ 85,411
Supplemental Cash Flow Information:		
Cash paid during the period:		
Interest	$ 36,137	$ 36,960
Income taxes	1,509	29,005
Non-cash financing and investing activities:		
Accounts payable for capital expenditures	9,967	2,860
Valuation adjustment for redeemable noncontrolling interests	(15,873)	2,931
Receivable for escrow amounts associated with the sale of Ecova	13,567	—

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS

Avista Corporation

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

	2014	2013
Common Stock, Shares:		
Shares outstanding at beginning of period	60,076,752	59,812,796
Issuance of common stock	143,347	167,227
Shares outstanding at end of period	60,220,099	59,980,023
Common Stock, Amount:		
Balance at beginning of period	$ 896,993	$ 889,237
Equity compensation expense	4,765	2,968
Issuance of common stock, net of issuance costs	1,980	3,017
Equity transactions of consolidated subsidiaries	(1,062)	33
Payment to option holders and redeemable noncontrolling interests for sale of Ecova	(20,871)	—
Excess tax benefits	3,936	—
Balance at end of period	885,741	895,255
Accumulated Other Comprehensive Loss:		
Balance at beginning of period	(5,819)	(6,700)
Other comprehensive income (loss)	1,809	(936)
Balance at end of period	(4,010)	(7,636)
Retained Earnings:		
Balance at beginning of period	407,092	376,940
Net income attributable to Avista Corporation shareholders	149,370	67,998
Cash dividends paid (common stock)	(38,327)	(36,667)
Valuation adjustments and other noncontrolling interests activity	10,150	(2,076)
Balance at end of period	528,285	406,195
Total Avista Corporation shareholders’ equity	1,410,016	1,293,814
Noncontrolling Interests:		
Balance at beginning of period	20,001	17,658
Net income attributable to noncontrolling interests	197	777
Deconsolidation of noncontrolling interests related to sale of Ecova	(23,612)	—
Other	2,943	2,172
Balance at end of period	(471)	20,607
Total equity	$ 1,409,545	$ 1,314,421
Redeemable Noncontrolling Interests:		
Balance at beginning of period	$ 15,889	$ 4,938
Net income (loss) attributable to noncontrolling interests	(4)	56
Purchase of subsidiary noncontrolling interests	(12)	(325)
Valuation adjustments and other noncontrolling interests activity	(15,873)	3,148
Balance at end of period	$ —	$ 7,817

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 June 30, 2014 and 2013 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, 2013 (2013 Form 10-K). Please refer to the section “Acronyms and Terms” in the 2013 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 an energy company engaged in the generation, transmission and distribution of electricity and distribution of natural gas, as well as other energy-related businesses. Avista Utilities is an operating division of Avista Corp., comprising the regulated utility operations. Avista Utilities provides electric distribution and transmission, as well as 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 generating facilities in Washington, Idaho, Oregon and Montana. The Company also supplies electricity to a small number of customers in Montana, most of whom are employees who operate one of the Montana generating facilities.

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 the year, 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 5 for information regarding the disposition of Ecova. On July 1, 2014, Avista Corp. completed its acquisition of Alaska Energy and Resources Company (AERC), and as of that date, AERC is a wholly-owned subsidiary of Avista Corp. See Note 4 for information regarding the acquisition of AERC. Also, see Note 13 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, there are no balance sheet amounts included for Ecova as they were disposed of as of June 30, 2014. 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 and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Utility taxes	$ 12,469	$ 12,238	$ 32,207	$ 30,144

Other Income-Net

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

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Interest income	$ 250	$ 238	$ 524	$ 496
Interest income on regulatory deferrals	51	8	95	21
Equity-related AFUDC	2,203	1,355	4,237	2,746
Net gain/(loss) on investments	185	154	145	(244)
Other income	366	437	654	932
Total	$ 3,055	$ 2,192	$ 5,655	$ 3,951

The prior period amounts included in the table above have been revised to include only the amounts related to continuing operations. All other amounts have been reclassified to discontinued operations.

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 June 30, 2014 and December 31, 2013 (dollars in thousands):

	June 30, 2014	December 31, 2013
Materials and supplies	$ 31,016	$ 28,747
Fuel stock	4,945	3,170
Natural gas stored	13,476	13,029
Total	$ 49,437	$ 44,946

Investments and Funds Held for Clients and Client Fund Obligations

In connection with the 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. Due to the disposition of Ecova on June 30, 2014, there are no longer any investments and funds held for clients as of June 30, 2014.

Investments and funds held for clients as of December 31, 2013 are as follows (dollars in thousands):

	Amortized Cost (1)	Unrealized Gain (Loss)	Fair Value
Cash and cash equivalents	$ 16,147	$ —	$ 16,147
Money market funds	11,180	—	11,180
Securities available for sale:			
U.S. government agency	63,633	(2,555)	61,078
Municipal	3,497	21	3,518
Corporate fixed income – financial	3,000	—	3,000
Corporate fixed income – industrial	753	12	765
Certificates of deposit	1,000	—	1,000
Total securities available for sale	71,883	(2,522)	69,361
Total investments and funds held for clients	$ 99,210	$ (2,522)	$ 96,688

(1) Amortized cost represents the original purchase price of the investments, plus or minus any amortized purchase premiums or accreted purchase discounts.

Investments and funds held for clients were classified as a current asset since these funds were held for the purpose of satisfying the client fund obligations. As of December 31, 2013, approximately 95 percent of the investment portfolio was rated AA-, Aa3 and higher by nationally recognized statistical rating organizations. All fixed income securities were rated as investment grade as of December 31, 2013.

Ecova management reviewed its investments continuously for indicators of other-than-temporary impairment. To make this determination, management employed a methodology that considers available quantitative and qualitative evidence in evaluating potential impairment of its investments. If the cost of an investment exceeded its fair value, management evaluated, among other factors, general market conditions, credit quality of instrument issuers, the length of time and extent to which the fair value is less than cost, and whether it had plans to sell the security or it is more-likely-than not that the Company will be required to sell the security before recovery. Management also considered specific adverse conditions related to the financial health of and specific prospects for the issuer as well as other cash flow factors. Once a decline in fair value was determined to be other-than-temporary, an impairment charge was recorded in earnings and a new cost basis in the investment was established. Based on management's analysis, securities available for sale did not meet the criteria for other-than-temporary impairment as of December 31, 2013.

The following is a summary of the disposition of available-for-sale securities for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Proceeds from sales, maturities and calls	$ 3,209	$ 8,130	$ 14,612	$ 15,130
Gross realized gains	—	16	3	18
Gross realized losses (1)	(735)	—	(735)	—

(1) The gross realized losses for both the three and six months ended June 30, 2014 were included in the determination of the gain on the disposal of Ecova and were not the result of selling any individual securities.

Contractual maturities of securities available for sale as of December 31, 2013 are as follows (dollars in thousands):

	Due within 1 year	After 1 but within 5 years	After 5 but within 10 years	After 10 years	Total
December 31, 2013	5,382	12,745	48,310	2,924	69,361

Actual maturities may differ due to call or prepayment rights and the effective maturity was 3.0 years as of December 31, 2013.

Goodwill

Goodwill arising from acquisitions represents the excess of the purchase price over the estimated fair value of net assets acquired. The Company evaluates goodwill for impairment using a combination of the discounted cash flow model and a market approach on at least an annual basis or more frequently if impairment indicators arise. The Company completed its annual evaluation of goodwill for potential impairment as of December 31, 2013 for Ecova and as of November 30, 2013 for the other businesses and determined that goodwill was not impaired at that time.

The changes in the carrying amount of goodwill are as follows (dollars in thousands):

	Ecova	Other	Accumulated Impairment Losses	Total
December 31, 2013	$ 71,011	$ 12,979	$ (7,733)	$ 76,257
Adjustments	112	—	—	112
Goodwill sold during the year	(71,123)	—	—	(71,123)
Balance as of June 30, 2014	$ —	$ 12,979	$ (7,733)	$ 5,246

Accumulated impairment losses are attributable to the other businesses. The goodwill sold during the year relates to the Ecova disposition, which occurred on June 30, 2014. See Note 5 for information regarding this sales transaction.

Intangible Assets

Amortization expense related to intangible assets was as follows for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Intangible asset amortization	$ 3,122	$ 3,098	$ 5,898	$ 5,677

All of the intangible assets were related to Ecova, which was disposed of as of June 30, 2014. As such, there are no intangible assets remaining as of June 30, 2014 and there is no amortization expense expected for the remainder of the year and in future years. The amortization expense disclosed in the table above is included in discontinued operations for all periods presented. See Note 5 for information regarding the Ecova sales transaction.

The gross carrying amount and accumulated amortization of intangible assets as of December 31, 2013 are as follows (dollars in thousands):

	Estimated Useful Lives	December 31, 2013
Client relationships	2 - 12 years	$ 33,562
Software development costs	3 - 7 years	39,327
Other	1 - 10 years	3,321
Total intangible assets		76,210
Client relationships accumulated amortization		(12,336)
Software development costs accumulated amortization		(21,861)
Other accumulated amortization		(2,437)
Total accumulated amortization		(36,634)
Total intangible assets - net		$ 39,576

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 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 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 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.

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 10 for the Company’s fair value disclosures.

Regulatory Deferred Charges and Credits

The Company prepares its condensed consolidated financial statements in accordance with regulatory accounting practices 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.

Redeemable Noncontrolling Interests

At December 31, 2013, certain option holders of Ecova had the right to put their shares back to Ecova at their discretion during an annual put window. Stock options and other outstanding redeemable stock were valued at their maximum redemption amount which is equal to their intrinsic value (fair value less exercise price). Due to the disposition of Ecova, as of June 30, 2014 there are no longer any redeemable noncontrolling interests.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax, consisted of the following as of June 30, 2014 and December 31, 2013 (dollars in thousands):

	June 30, 2014	December 31, 2013
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $(2,159) and $(2,280), respectively	$ (4,010)	$ (4,233)
Unrealized loss on securities available for sale - net of taxes of $0 and $(936), respectively (1)	—	(1,586)
Total accumulated other comprehensive loss	$ (4,010)	$ (5,819)

(1) This entire balance was related to Ecova, which was disposed of as of June 30, 2014.

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

Details about Accumulated Other Comprehensive Loss Components	Amounts Reclassified from Accumulated Other Comprehensive Loss — Three months ended June 30, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013	Affected Line Item in Statement of Income
Realized gains on investment securities	$ —	$ 16	$ 3	$ 18	(a)
Realized losses on investment securities	(735)	—	(735)	—	(a)
	(735)	16	(732)	18	Total before tax
	273	(6)	272	(7)	Tax benefit (expense) (a)
	$ (462)	$ 10	$ (460)	$ 11	Net of tax
Amortization of defined benefit pension items					
Amortization of net loss	$ (1,952)	$ (4,891)	$ (3,904)	$ (9,782)	(b)
Adjustment due to effects of regulation	1,778	4,609	3,560	9,217	(b)
	(174)	(282)	(344)	(565)	Total before tax
	62	99	121	198	Tax benefit
	$ (112)	$ (183)	$ (223)	$ (367)	Net of tax

(a) These amounts were included as part of net income from discontinued operations for all periods presented (see Note 5 for additional details).
(b) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 7 for additional details).

Appropriated Retained Earnings

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

The appropriated retained earnings amounts included in retained earnings were as follows as of June 30, 2014 and December 31, 2013 (dollars in thousands):

	June 30, 2014	December 31, 2013
Appropriated retained earnings	$ 14,270	$ 9,714

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, and
- the hydroelectric licensing requirements of section 10(d) of the FPA.

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 June 30, 2014 was limited to approximately $395.7 million.

Stock Repurchase Program

On June 13, 2014, Avista Corp.'s Board of Directors approved the repurchase of up to 4 million shares of the Company's outstanding common stock. Repurchases of common stock commenced on July 7, 2014 and will not continue past December 31, 2014. The Company can also choose to terminate the repurchase program before December 31, 2014. Repurchases are made in the open market or in privately negotiated transactions. There is no assurance that the goal of repurchasing 4 million shares will be achieved. Through July 31, 2014, the Company has repurchased 292,100 shares at a total cost of $9.4 million and an average cost of $32.28 per share. All repurchased shares revert 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.

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 has evaluated this standard and determined that it will not early adopt this standard. As such, there is no impact to 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. The Company is currently evaluating this standard and cannot, at this time, predict the potential impact to its future financial condition, results of operations and cash flows.

NOTE 3. VARIABLE INTEREST ENTITIES

Lancaster Power Purchase Agreement

The Company has a power purchase agreement (PPA) for the purchase of all the output of the Lancaster Plant, a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho, owned by an unrelated third-party (Rathdrum Power LLC), through 2026.

Avista Corp. has a variable interest in the PPA. Accordingly, Avista Corp. made an evaluation of which interest holders have the power to direct the activities that most significantly impact the economic performance of the entity and which interest holders have the obligation to absorb losses or receive benefits that could be significant to the entity. Avista Corp. pays a fixed capacity and operations and maintenance payment and certain monthly variable costs under the PPA. Under the terms of the PPA, Avista Corp. makes the dispatch decisions, provides all natural gas fuel and receives all of the electric energy output from the Lancaster Plant. However, Rathdrum Power LLC (the owner) controls the daily operation of the Lancaster Plant and makes operating and maintenance decisions. Rathdrum Power LLC controls all of the rights and obligations of the Lancaster Plant after the expiration of the PPA in 2026. It is estimated that the plant will have 15 to 25 years of useful life after that time. Rathdrum Power LLC bears the maintenance risk of the plant and will receive the residual value of the Lancaster Plant. Avista Corp. has no debt or equity investments in the Lancaster Plant and does not provide financial support through liquidity arrangements or other commitments (other than the PPA). Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Lancaster Plant. Accordingly, neither the Lancaster Plant nor Rathdrum Power LLC is included in Avista Corp.'s condensed consolidated financial statements. The Company has a future contractual obligation of approximately

$286 million under the PPA (representing the fixed capacity and operations and maintenance payments through 2026) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

Palouse Wind Power Purchase Agreement

In June 2011, the Company entered into a 30-year PPA with Palouse Wind, LLC (Palouse Wind), an affiliate of First Wind Holdings, LLC. The PPA relates to a wind project that was developed by Palouse Wind in Whitman County, Washington and under the terms of the PPA, the Company acquires all of the power and renewable attributes produced by the wind project for a fixed price per MWh, which escalates annually, without consideration for market fluctuations. The wind project has a nameplate capacity of approximately 105 MW and is expected to produce approximately 40 aMW annually. The project was completed and energy deliveries began during the fourth quarter of 2012. Under the PPA, the Company has an annual option to purchase the wind project following the 10^{th} anniversary of the commercial operation date at a fixed price determined under the contract.

The Company evaluated this agreement to determine if it has a variable interest which must be consolidated. Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Palouse Wind facility due to the fact that it pays a fixed price per MWh, which represents the only financial obligation, and does not have any input into the management of the day-to-day operations of the facility. Accordingly, Palouse Wind is not included in Avista Corp.'s condensed consolidated financial statements. The Company has a future contractual obligation of approximately $595 million under the PPA (representing the charges associated with purchasing the energy and renewable attributes through 2042) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

NOTE 4. BUSINESS ACQUISITIONS

Alaska Energy and Resources Company

On July 1, 2014, the Company completed its acquisition of Alaska Energy and Resources Company (AERC), based in Juneau, Alaska. As of July 1, 2014 AERC is a wholly-owned subsidiary of Avista Corp.

The primary subsidiary of AERC is Alaska Electric Light and Power Company (AEL&P), a regulated utility which provides electric services to approximately 16,000 customers in the City and Borough of Juneau, Alaska. In 2013, AEL&P had 60 full-time employees. Its rate base, based on the 2013 test year was $109 million. The utility has a firm retail peak load of approximately 68 MW. AEL&P owns four hydroelectric generating facilities, having a total present capacity of 24.7 MW, and has a power purchase commitment for the output of the Snettisham hydroelectric project, having a present capacity of 78 MW, for a total hydroelectric capacity of 102.7 MW. AEL&P is not interconnected to any other electric system. The utility also has 93.9 MW of diesel generating capacity to provide back-up service to firm customers when necessary.

In addition to the regulated utility, AERC owns AJT Mining Properties, Inc. (AJT Mining), which is an inactive mining company holding certain properties.

The purpose of this acquisition is 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, Avista Corp. issued 4.5 million new shares of common stock to the shareholders of AERC at a price of $32.46 per share, which reflects a purchase price of $170 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). For determining the fair value of the consideration transferred, the Company used the closing stock price of Avista Corp. common stock on July 1, 2014, which was $33.35 per share. The difference between the adjusted contract price and the fair value of the consideration transferred was recorded to goodwill.

The contract acquisition price and the fair value of consideration transferred for AERC as of July 1, 2014 were as follows (in thousands):

		July 1, 2014
Contract acquisition price (using $32.46 per share stock price)		
Gross contract price	$	170,000
Acquired cash		19,704
Acquired debt (excluding capital lease obligation)		(38,832)
Other closing adjustments		(104)
Total adjusted contract price	$	150,768
Fair value of consideration transferred		
Avista Corp. common stock (4,500,014 shares at $33.35 per share)	$	150,075
Cash		4,697
Fair value of total consideration transferred	$	154,772

The preliminary estimated fair value of assets acquired and liabilities assumed as of July 1, 2014 were as follows (in thousands):

		July 1, 2014
Assets acquired:		
Current Assets:		
Cash	$	19,704
Accounts receivable-less allowance of $77		3,851
Materials and supplies		2,017
Other current assets		999
Total current assets		26,571
Utility Property:		
Utility plant in service		113,964
Utility property under long-term capital lease		71,007
Construction work in progress		3,440
Total utility property		188,411
Other Non-current Assets:		
Non-utility property		6,660
Electric plant held for future use		3,711
Goodwill		50,629
Other deferred charges and non-current assets		5,368
Total other non-current assets		66,368
Total assets	$	281,350

	July 1, 2014
Liabilities Assumed:	
Current Liabilities:	
Accounts payable	$ 700
Current portion of long-term debt and capital lease obligations	3,773
Other current liabilities	2,901
Total current liabilities	7,374
Long-term debt	37,227
Capital lease obligations	68,840
Other non-current liabilities and deferred credits	13,137
Total liabilities	$ 126,578
Total identifiable net assets acquired	$ 154,772

The majority of AERC's operations are subject to the rate-setting authority of the Regulatory Commission of Alaska and are accounted for pursuant to U.S. 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 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 following table summarizes the supplemental pro forma revenue, net income and earnings per share information for the three and six months ended June 30 related to the acquisition of AERC as if the acquisition had occurred on January 1, 2013 (in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Actual Avista Corp. revenues from continuing operations	$ 312,580	$ 307,488	$ 759,158	$ 747,987
Actual Avista Corp. revenues from discontinued operations	43,150	44,560	87,534	86,967
Supplemental pro forma AERC revenues (1)	11,782	10,651	24,546	23,303
Total supplemental pro forma revenues	367,512	362,699	871,238	858,257
Actual Avista Corp. net income from continuing operations attributable to Avista Corp. shareholders	31,254	24,212	78,730	65,432
Actual Avista Corp. net income from discontinued operations attributable to Avista Corp. shareholders	69,617	1,445	70,640	2,566
Acquisition costs removed from Avista Corp.'s net income (2)	219	—	672	—
Supplemental pro forma AERC net income (1) (5)	2,371	1,810	5,627	7,435
Total supplemental pro forma net income	$ 103,461	$ 27,467	$ 155,669	$ 75,433
Pro forma weighted-average common shares outstanding (thousands), basic (3)	64,684	64,437	64,653	64,426
Pro forma weighted-average common shares outstanding (thousands), diluted (3)	64,963	64,462	64,816	64,454
Pro forma earnings per common share attributable to Avista Corp. shareholders				
Total pro forma earnings per common share attributable to Avista Corp. shareholders, basic	$ 1.60	$ 0.43	$ 2.41	$ 1.17
Total pro forma earnings per common share attributable to Avista Corp. shareholders, diluted (4)	$ 1.59	$ 0.43	$ 2.40	$ 1.17

(1) Since AERC was acquired on July 1, 2014, none of the supplemental revenues and net income have been included in the actual results of Avista Corp. for the three and six months ended June 30.

(2) The transaction costs have been expensed and presented in the Condensed Consolidated Statements of Income in other operating expenses within utility operating expenses. Since the start of the planned transaction through June 30, 2014, Avista Corp. has expensed $2.3 million (pre-tax) in total transaction fees associated with the transaction. All of the transaction expenses in 2013 were incurred during the second half of 2013. In addition to the amounts expensed, Avista Corp. has included $0.4 million in fees through June 30, 2014 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.

(3) The 4.5 million shares issued on July 1, 2014 for the acquisition of AERC were assumed to be issued on January 1, 2013 for purposes of calculating the pro forma weighted average shares outstanding.

(4) The pro forma diluted earnings per share calculation ignores the impact of the subsidiary earnings adjustment for dilutive securities for discontinued operations as disclosed at Note 11. Earnings per Common Share Attributable to Avista Corp. Shareholders. Including this dilutive impact would not change the diluted pro forma earnings per share amount disclosed above.

(5) The net income for the six months ended June 30, 2013 at AERC includes a gain on the sale of property of approximately $2.3 million that does not occur every year.

NOTE 5. DISCONTINUED OPERATIONS

On May 29, 2014, Avista Capital, Inc., the non-regulated subsidiary of Avista Corp., entered into a definitive agreement to sell 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 sales transaction was completed on June 30, 2014 for a sales price of $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 $16.75 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 $1.5 million will be held in escrow pending resolution of adjustments to working capital (which is expected to occur before the end of 2014).

Avista Capital and Cofely USA Inc. agreed to make an election under Internal Revenue 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 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 $133.2 million (see reconciliation below) and result in a net gain of $68.1 million. The Company expects to receive the full amount of its portion of the escrow accounts; therefore, the full amounts have been included in the gain calculation.

The summary of cash proceeds associated with the sales transaction are as follows (in thousands):

	June 30, 2014
Reconciliation to Statement of Cash Flows	
Contract price	$ 335,000
Closing adjustments	4,402
Gross proceeds from sale (1)	339,402
Cash sold in the transaction	(95,932)
Avista Corp. portion of proceeds held in escrow	(13,567)
Gross proceeds from sale of Ecova, net of cash sold (per Statement of Cash Flows)	$ 229,903
Reconciliation of expected net proceeds	
Gross proceeds from sale (1)	$ 339,402
Repayment of long-term borrowings under committed line of credit	(40,000)
Payment to option holders and redeemable noncontrolling interests	(20,871)
Payment to noncontrolling interests	(54,179)
Transaction expenses withheld from proceeds	(5,390)
Avista Corp. portion of proceeds held in escrow	(13,567)
Net proceeds to Avista Capital at transaction closing	205,395
Estimated tax payments to be made in 2014	(85,756)
Avista Corp. portion of proceeds held in escrow to be received in the future	13,567
Total net proceeds related to sales transaction	$ 133,206

(1) Of this total amount, approximately $16.75 million will be held in escrow for 15 months from the transaction closing date for any indemnity claims and an additional $1.5 million will be held in escrow pending resolution of adjustments to working capital (which is expected to occur before the end of 2014).

Prior to the completion of the sales transaction, Ecova was a reportable business segment. The major classes of assets and liabilities and their carrying amounts immediately prior to the completion of the sales transaction were as follows:

		June 30, 2014
Assets:		
Current Assets:		
Cash and cash equivalents	$	95,932
Accounts and notes receivable-less allowances of $410		32,070
Investments and funds held for clients		114,598
Income taxes receivable		2,548
Other current assets		8,908
Total current assets		254,056
Other Non-current Assets:		
Goodwill		71,123
Intangible assets-net of accumulated amortization of $42,266		37,185
Other property and investments-net		4,656
Total other non-current assets		112,964
Total assets		367,020
Liabilities:		
Current Liabilities:		
Accounts payable		72,453
Client fund obligations		115,333
Current portion of long-term debt		67
Other current liabilities		35,329
Total current liabilities		223,182
Long-term borrowings under committed line of credit		40,000
Other non-current liabilities		2,117
Total liabilities	$	265,299

Amounts reported in discontinued operations for 2013 and 2014 relate solely to the Ecova business segment. The following table presents amounts that were included in discontinued operations for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Revenues	$ 43,150	$ 44,560	$ 87,534	$ 86,967
Gain on sale of Ecova (1)	161,100	—	161,100	—
Transaction expenses and accelerated employee benefits (2)	8,976	—	8,976	—
Gain on sale of Ecova, net of transaction expenses	152,124	—	152,124	—
Income before income taxes	154,190	2,593	156,599	5,459
Income tax expense	84,878	1,102	85,772	2,086
Net income from discontinued operations	69,312	1,491	70,827	3,373
Net loss (income) attributable to noncontrolling interests	305	(46)	(187)	(807)
Net income from discontinued operations attributable to Avista Corp. shareholders	$ 69,617	$ 1,445	$ 70,640	$ 2,566

(1) This represents the gross gain recorded to discontinued operations. The gain net of taxes and transactions expenses is $68.1 million.

(2) This represents Avista Corp.'s portion of the total transaction expenses. All transaction expenses paid on the Ecova sale were $10.9 million, of which $5.4 million were withheld from the net proceeds and the remainder were paid during the second 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 6. DERIVATIVES AND RISK MANAGEMENT

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 June 30, 2014 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
2014	515	1,467	13,854	80,796	465	1,768	2,620	59,008
2015	508	1,546	7,113	103,025	222	2,935	1,490	68,710
2016	397	948	2,505	56,680	287	1,634	910	46,220
2017	397	—	675	—	286	—	—	—
2018	397	—	—	—	286	—	—	—
Thereafter	235	—	—	—	158	—	—	—

(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 sixty 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 June 30, 2014 and December 31, 2013 (dollars in thousands):

	June 30, 2014	December 31, 2013
Number of contracts	26	23
Notional amount (in United States dollars)	$ 9,719	$ 8,631
Notional amount (in Canadian dollars)	10,519	9,191

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 it focuses on the steps management has undertaken to control it. The Risk Management Committee also reviews the interest risk management plan. Avista Corp. has established a policy to limit its 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 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 June 30, 2014 and December 31, 2013 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
June 30, 2014	2	$ 50,000	2014
	4	70,000	2015
	4	80,000	2016
	3	45,000	2017
	6	135,000	2018
December 31, 2013	2	50,000	2014
	2	45,000	2015
	2	40,000	2016
	1	15,000	2017
	4	95,000	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.

Derivative Instruments Summary

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of June 30, 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 assets	$ 136	$ (1)	$ —	$ 135
Interest rate contracts	Other current assets	8,211	—	—	8,211
Interest rate contracts	Other property and investments - net	5,809	(2,269)	—	3,540
Interest rate contracts	Other non-current liabilities and deferred credits	1,617	(22,308)	7,040	(13,651)
Commodity contracts (1)	Current utility energy commodity derivative assets	50,416	(39,547)	—	10,869
Commodity contracts (1)	Non-current utility energy commodity derivative assets	367	(92)	—	275
Commodity contracts (1)	Current utility energy commodity derivative liabilities	2,232	(5,610)	—	(3,378)
Commodity contracts (1)	Other non-current liabilities and deferred credits	22,375	(35,954)	3,051	(10,528)
Total derivative instruments recorded on the balance sheet		$ 91,163	$ (105,781)	$ 10,091	$ (4,527)

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of December 31, 2013 (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 assets	$ 7	$ (6)	$ —	$ 1
Interest rate contracts	Other current assets	13,968	—	—	13,968
Interest rate contracts	Other property and investments - net	19,575	—	—	19,575
Commodity contracts (1)	Current utility energy commodity derivative assets	7,416	(4,394)	—	3,022
Commodity contracts (1)	Non-current utility energy commodity derivative assets	7,610	(6,756)	—	854
Commodity contracts (1)	Current utility energy commodity derivative liabilities	23,455	(37,306)	2,976	(10,875)
Commodity contracts (1)	Other non-current liabilities and deferred credits	17,101	(41,213)	5,756	(18,356)
Total derivative instruments recorded on the balance sheet		$ 89,132	$ (89,675)	$ 8,732	$ 8,189

(1) Avista Corp. had a master netting agreement that governed the transactions of multiple affiliated legal entities under this single master netting agreement. This master netting agreement allowed for cross-commodity netting (i.e. netting physical power, physical natural gas, and financial transactions) and cross-affiliate netting for the parties to the agreement. Avista Corp. performed cross-commodity netting for each legal entity that is a party to the master netting agreement for presentation in the Condensed Consolidated Balance Sheets; however, Avista Corp. did not perform cross-affiliate netting because the Company believed that cross-affiliate netting may not be enforceable. Therefore, the requirements for cross-affiliate netting under ASC 210-20-45 were not applicable for Avista Corp. As of December 31, 2013, all derivatives for each affiliated entity under this master netting agreement were in a net liability position. As such, there was no additional netting which required disclosure for that period. In May 2014, this master netting agreement was terminated and each affiliated legal entity is now under their own separate agreement. As of June 30, 2014, the Company no longer has any agreements where cross-affiliate netting is allowed under the agreement, but not performed by the Company.

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. As of June 30, 2014, the Company had deposited cash in the amount of $9.4 million and letters of credit of $14.8 million as collateral for certain energy derivative contracts. The Company also had deposited cash in the amount of $7.0 million as collateral for its interest rate swap derivative contracts. The Condensed Consolidated Balance Sheet at June 30, 2014 reflects the offsetting of $10.1 million of cash collateral against net derivative positions where a legal right of offset exists. As of December 31, 2013, the Company had deposited cash in the amount of $26.1 million and letters of credit of $20.3 million as collateral for certain energy derivative contracts. As of June 30, 2014 and December 31, 2013, the Company did not hold any cash as collateral from counterparties for energy derivative contracts. The Consolidated Balance Sheet at December 31, 2013 reflects the offsetting of $8.7 million of cash collateral against net derivative positions where a legal right of offset exists.

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 aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position as of June 30, 2014 was $4.1 million. If the credit-risk-related contingent features underlying these agreements were triggered on June 30, 2014, the Company could be required to post $3.9 million of additional collateral to its counterparties. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of

December 31, 2013 was $13.3 million. If the credit-risk-related contingent features underlying these agreements had been triggered on December 31, 2013, the Company could have been required to post $12.6 million of additional collateral to its counterparties.

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 7. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The pension and other postretirement benefit plans described below only relate to Avista Utilities and do not cover any of the subsidiary employees. The Company's former subsidiary, Ecova, had a 401(k) savings plan that was separate from those described below and this plan had historically not been significant to the Company. In addition, as of June 30, 2014 Ecova is no longer part of the Company due to its disposition.

The Company has a defined benefit pension plan covering substantially 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 $21.5 million in cash to the pension plan for the six months ended June 30, 2014. The Company expects to contribute a total of $32.0 million in cash to the pension plan in 2014. The Company contributed $44.3 million in cash to the pension plan in 2013.

In October 2013, the Company revised its defined benefit pension plan such that as of January 1, 2014 the plan is closed to all non-union employees hired or rehired by the Company on or after January 1, 2014. All actively employed non-union employees that were hired prior to January 1, 2014 and who are currently covered under the defined benefit pension plan will continue accruing benefits as originally specified in the plan. A new and separate defined contribution 401(k) plan replaced the defined benefit pension plan for all non-union employees hired or rehired on or after January 1, 2014. Under the new defined contribution plan, the Company provides a non-elective contribution as a percentage of each employee's pay based on his or her age. This new defined contribution plan is in addition to the existing 401(k) plan in which the Company matches a portion of the pay deferred by each participant. In addition to the above changes, the Company has also revised its lump sum calculation from its previous lump sum calculation for non-union participants who retire under the defined benefit pension plan to provide non-union retirees on or after January 1, 2014 with a lump sum amount equivalent to the present value of the benefits based upon applicable discount rates. In April 2014, the local union in Oregon for the International Brotherhood of Electrical Workers accepted the above plan changes in the latest collective bargaining agreement, and the plan changes are effective for Oregon union workers hired or rehired on or after April 1, 2014.

The Company also has a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to executive officers of the Company. The SERP is intended to provide benefits to executive officers 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 substantially all of its retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. In October 2013, the Company revised the health care benefit plan such that beginning on January 1, 2020, the method for calculating health insurance premiums for non-union retirees under age 65 and active Company employees was revised. The revisions resulted in separate health insurance premium calculations for each group. In addition, for non-union employees hired or rehired on or after January 1, 2014, upon retirement the Company will provide access to its retiree medical plan, but will no longer provides a contribution towards his or her medical premiums and the employee will pay the full cost of premiums upon retirement. In April 2014, the local union in Oregon for the International Brotherhood of Electrical Workers accepted the above plan changes in the latest collective bargaining agreement, and the plan changes are effective for Oregon union workers hired or rehired on or after April 1, 2014.

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 and six months ended June 30 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2014	2013	2014	2013
Three months ended June 30:				
Service cost	$ 3,868	$ 4,743	$ 499	$ 1,032
Interest cost	6,706	5,978	1,353	1,390
Expected return on plan assets	(8,110)	(6,900)	(472)	(400)
Amortization of prior service cost	6	75	(43)	(37)
Net loss recognition	14	3,222	349	1,426
Net periodic benefit cost	$ 2,484	$ 7,118	$ 1,686	$ 3,411
Six months ended June 30:				
Service cost	$ 8,886	$ 9,486	$ 1,473	$ 2,064
Interest cost	13,412	11,956	2,706	2,780
Expected return on plan assets	(16,220)	(13,800)	(944)	(800)
Amortization of prior service cost	12	150	(86)	(74)
Net loss recognition	1,171	6,769	1,175	2,947
Net periodic benefit cost	$ 7,261	$ 14,561	$ 4,324	$ 6,917

NOTE 8. COMMITTED LINES OF CREDIT

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400 million. In April 2014, the Company amended this committed line of credit agreement to extend the expiration date to April 2019. The amendment also provides the Company the option to request an extension for an additional one or two years beyond April 2019, provided there is no event of default prior to the requested extension and the requested extension does not cause the remaining term until the expiration date to exceed five years. The amendment did not change the amount of the committed line of credit.

The committed line of credit is secured by non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of “consolidated total debt” to “consolidated total capitalization” of Avista Corp. to be greater than 65 percent at any time. As of June 30, 2014, the Company was in compliance with this covenant.

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 June 30, 2014 and December 31, 2013 (dollars in thousands):

	June 30, 2014	December 31, 2013
Borrowings outstanding at end of period	$ 151,500	$ 171,000
Letters of credit outstanding at end of period	$ 21,864	$ 27,434
Average interest rate on borrowings at end of period	3.02%	1.02%

As of June 30, 2014 the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Condensed Consolidated Balance Sheet.

On July 1, 2014, the Company utilized a portion of the proceeds from the Ecova sales transaction to pay off the entire balance of the outstanding committed line of credit.

Ecova

Ecova had a $125.0 million committed line of credit agreement with various financial institutions that had an expiration date of July 2017. The credit agreement was secured by all of Ecova's assets excluding investments and funds held for clients. Since Ecova was disposed of as of June 30, 2014, the balance of this credit agreement is no longer on the balance sheet as of June 30, 2014.

The balance outstanding and interest rate of borrowings under Ecova's credit agreement were as follows as of December 31, 2013 (dollars in thousands):

	December 31, 2013
Borrowings outstanding at end of period	$ 46,000
Average interest rate on borrowings at end of period	2.17%

As of December 31, 2013 the borrowings outstanding under Ecova's committed line of credit were classified as long-term borrowings under committed line of credit on the Condensed Consolidated Balance Sheet.

NOTE 9. LONG-TERM DEBT

The following details long-term debt outstanding as of June 30, 2014 and December 31, 2013 (dollars in thousands):

Maturity Year	Description	Interest Rate	June 30, 2014	December 31, 2013
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
2047	First Mortgage Bonds	4.23%	80,000	80,000
	Total secured long-term debt		1,376,700	1,376,700
	Other long-term debt and capital leases		4,348	4,630
	Settled interest rate swaps (2)		(23,265)	(23,560)
	Unamortized debt discount		(1,205)	(1,287)
	Total		1,356,578	1,356,483
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Current portion of long-term debt		(4,348)	(358)
	Total long-term debt		$ 1,268,530	$ 1,272,425

(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.

Nonrecourse Long-Term Debt

Nonrecourse long-term debt (including current portion) represents the long-term debt of Spokane Energy. To provide funding to acquire a long-term fixed rate electric capacity contract from Avista Corp., Spokane Energy borrowed $145.0 million from a funding trust in December 1998. The long-term debt has scheduled monthly installments and interest at a fixed rate of 8.45 percent with the final payment due in January 2015. Spokane Energy bears full recourse risk for the debt, which is secured by the fixed rate electric capacity contract and $1.6 million of funds held in a trust account. As of June 30, 2014, the entire remaining portion of the nonrecourse debt has been included in current liabilities due to its maturity in January 2015.

NOTE 10. 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, but excluding 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 June 30, 2014 and December 31, 2013 (dollars in thousands):

	June 30, 2014		December 31, 2013	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 951,000	$ 1,103,475	$ 951,000	$ 1,054,512
Long-term debt (Level 3)	342,000	351,965	342,000	329,581
Nonrecourse long-term debt (Level 3)	9,812	10,058	17,838	18,636
Long-term debt to affiliated trusts (Level 3)	51,547	38,145	51,547	37,114

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information. Due to the unique nature of the long-term fixed rate electric capacity contract securing the long-term debt of Spokane Energy (nonrecourse long-term debt), the estimated fair value of nonrecourse long-term debt was determined based on a discounted cash flow model using available market information.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Condensed Consolidated Balance Sheets as of June 30, 2014 and December 31, 2013 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
June 30, 2014					
Assets:					
Energy commodity derivatives	$ —	$ 72,982	$ —	$ (61,838)	$ 11,144
Level 3 energy commodity derivatives:					
Power exchange agreement	—	—	2,408	(2,408)	—
Foreign currency derivatives	—	136	—	(1)	135
Interest rate swaps	—	15,637	—	(3,886)	11,751
Funds held in trust account of Spokane Energy	1,600	—	—	—	1,600
Deferred compensation assets:					
Fixed income securities (2)	1,879	—	—	—	1,879
Equity securities (2)	6,424	—	—	—	6,424
Total	$ 9,903	$ 88,755	$ 2,408	$ (68,133)	$ 32,933
Liabilities:					
Energy commodity derivatives	$ —	$ 68,088	$ —	$ (64,889)	$ 3,199
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	2,183	—	2,183
Power exchange agreement	—	—	10,327	(2,408)	7,919
Power option agreement	—	—	605	—	605
Foreign currency derivatives	—	1	—	(1)	—
Interest rate swaps	—	24,577	—	(10,926)	13,651
Total	$ —	$ 92,666	$ 13,115	$ (78,224)	$ 27,557

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2013					
Assets:					
Energy commodity derivatives	$ —	$ 55,243	$ —	$ (51,367)	$ 3,876
Level 3 energy commodity derivatives:					
Power exchange agreement	—	—	339	(339)	—
Foreign currency derivatives	—	7	—	(6)	1
Interest rate swaps	—	33,543	—	—	33,543
Investments and funds held for clients:					
Money market funds	11,180	—	—	—	11,180
Securities available for sale:					
U.S. government agency	—	61,078	—	—	61,078
Municipal	—	3,518	—	—	3,518
Corporate fixed income – financial	—	3,000	—	—	3,000
Corporate fixed income – industrial	—	765	—	—	765
Certificate of deposits	—	1,000	—	—	1,000
Funds held in trust account of Spokane Energy	1,600	—	—	—	1,600
Deferred compensation assets:					
Fixed income securities (2)	1,960	—	—	—	1,960
Equity securities (2)	6,470	—	—	—	6,470
Total	$ 21,210	$ 158,154	$ 339	$ (51,712)	$ 127,991
Liabilities:					
Energy commodity derivatives	$ —	$ 72,895	$ —	$ (60,099)	$ 12,796
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	1,219	—	1,219
Power exchange agreement	—	—	14,780	(339)	14,441
Power option agreement	—	—	775	—	775
Foreign currency derivatives	—	6	—	(6)	—
Total	$ —	$ 72,901	$ 16,774	$ (60,444)	$ 29,231

(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 $0.9 million as of June 30, 2014 and $0.7 million as of December 31, 2013.

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 for years beyond 2013, and 3) volatility rates for periods beyond July 2017. 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 June 30, 2014 (dollars in thousands):

	Fair Value (Net) at June 30, 2014	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (7,919)	Surrogate facility pricing	O&M charges	$30.18-$53.90/MWh (1)
			Escalation factor	3% - 2014 to 2019
			Transaction volumes	310,103 - 397,116 MWhs
Power option agreement	(605)	Black-Scholes-Merton	Strike price	$58.18/MWh - 2016
				$71.88/MWh - 2019
			Delivery volumes	110,854 - 287,147 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreement	(2,183)	Internally derived weighted average cost of gas	Forward purchase prices	$3.57 - $3.86/mmBTU
			Forward sales prices	$4.47 - $5.16/mmBTU
			Purchase volumes	280,000 - 310,000 mmBTUs
			Sales volumes	279,990 - 310,000 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2013 were $40.93 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 2013 were $42.44 for Washington and $40.93 for Idaho.
(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.27 for 2014 to 0.20 in July 2017.

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 six months ended June 30 (dollars in thousands):

	Natural Gas Exchange Agreement	Power Exchange Agreement	Power Option Agreement	Total
Three months ended June 30, 2014:				
Balance as of April 1, 2014	$ (2,418)	$ (13,624)	$ (428)	$ (16,470)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	235	5,029	(177)	5,087
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	—	676	—	676
Transfers to/from other categories	—	—	—	—
Ending balance as of June 30, 2014	$ (2,183)	$ (7,919)	$ (605)	$ (10,707)
Three months ended June 30, 2013:				
Balance as of April 1, 2013	$ (1,991)	$ (16,463)	$ (1,200)	$ (19,654)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	1,057	(6,272)	604	(4,611)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(88)	556	—	468
Transfers to/from other categories	—	—	—	—
Ending balance as of June 30, 2013	$ (1,022)	$ (22,179)	$ (596)	$ (23,797)
Six months ended June 30, 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)	2,084	7,055	170	9,309
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(3,048)	(533)	—	(3,581)
Transfers to/from other categories	—	—	—	—
Ending balance as of June 30, 2014	$ (2,183)	$ (7,919)	$ (605)	$ (10,707)

	Natural Gas Exchange Agreement	Power Exchange Agreement	Power Option Agreement	Total
Six months ended June 30, 2013:				
Balance as of January 1, 2013	$ (2,379)	$ (18,692)	$ (1,480)	$ (22,551)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	1,807	(6,248)	884	(3,557)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(450)	2,761	—	2,311
Transfers from other categories	—	—	—	—
Ending balance as of June 30, 2013	$ (1,022)	$ (22,179)	$ (596)	$ (23,797)

(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 11. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORP. SHAREHOLDERS

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

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Numerator:				
Net income from continuing operations attributable to Avista Corp. shareholders	$ 31,254	$ 24,212	$ 78,730	$ 65,432
Net income from discontinued operations attributable to Avista Corp. shareholders	69,617	1,445	70,640	2,566
Subsidiary earnings adjustment for dilutive securities (discontinued operations)	58	(39)	5	(82)
Adjusted net income from discontinued operations attributable to Avista Corp. shareholders for computation of diluted earnings per common share	$ 69,675	$ 1,406	$ 70,645	$ 2,484
Denominator:				
Weighted-average number of common shares outstanding-basic	60,184	59,937	60,153	59,926
Effect of dilutive securities:				
Performance and restricted stock awards	279	25	163	28
Weighted-average number of common shares outstanding-diluted	60,463	59,962	60,316	59,954
Earnings per common share attributable to Avista Corp. shareholders, basic:				
Earnings per common share from continuing operations	$ 0.52	$ 0.40	$ 1.31	$ 1.09
Earnings per common share from discontinued operations	$ 1.16	$ 0.03	$ 1.17	$ 0.04
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 1.68	$ 0.43	$ 2.48	$ 1.13
Earnings per common share attributable to Avista Corp. shareholders, diluted:				
Earnings per common share from continuing operations	$ 0.52	$ 0.40	$ 1.31	$ 1.09
Earnings per common share from discontinued operations	$ 1.15	$ 0.03	$ 1.17	$ 0.04
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 1.67	$ 0.43	$ 2.48	$ 1.13

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

NOTE 12. 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’ operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

Federal Energy Regulatory Commission Inquiry

In April 2004, the Federal Energy Regulatory Commission (FERC) approved the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) which stated that there was: (1) no evidence that any executives or employees of Avista Utilities or Avista Energy knowingly engaged in or facilitated any improper trading strategy during 2000 and 2001; (2) no evidence that Avista Utilities or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; and (3) no finding that Avista Utilities or Avista Energy withheld relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001 (Trading Investigation). In May 2004, the FERC provided notice that Avista

Energy was no longer subject to an investigation reviewing certain bids above $250 per MW in energy markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX)(Bidding Investigation). Appeals of the FERC's decisions are pending before the United States Court of Appeals for the Ninth Circuit (Ninth Circuit).

On March 7, 2014, Avista Utilities and Avista Energy filed at FERC a settlement with Pacific Gas & Electric (PG&E), Southern California Edison, San Diego Gas & Electric, the California Attorney General (AG), the California Department of Water Resources (CERS), and the California Public Utilities Commission (together, the "California Parties") that resolves both the Trading Investigation and the Bidding Investigation. The settlement was approved by the FERC and is final so there is no longer any potential liability.

California Refund Proceeding

In July 2001, the FERC ordered an evidentiary hearing to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the CalISO and the CalPX during the period from October 2, 2000 to June 20, 2001 (Refund Period). Petitions for review of the FERC's decisions are still pending in the Ninth Circuit. In August 2006, the Ninth Circuit remanded to the FERC its decision not to consider a Federal Power Act (FPA) section 309 remedy for tariff violations prior to October 2, 2000. During the FERC hearing on the remand in 2012, the Presiding Administrative Law Judge (ALJ) issued a partial initial decision granting Avista Utilities' motion for summary disposition. On November 2, 2012, the FERC issued an order affirming the partial initial decision and dismissing Avista Utilities from the proceeding. On February 15, 2013, the ALJ issued an Initial Decision that may have subjected Avista Energy to additional refund liability. Exceptions to the Initial Decision were filed and are pending before the FERC.

On March 7, 2014, Avista Utilities, Avista Energy and the California Parties filed a settlement at the FERC that fully resolved these matters. Because Avista Energy had not been paid for all of its sales during the Refund Period, substantial funds have been held in escrow accounts pending resolution of this proceeding. The settlement returned $15.0 million of Avista Energy's receivable to Avista Energy, with the balance of the Avista Energy receivable flowing to the purchasers associated with the hourly transactions at issue. The settlement funds were received on June 23, 2014 and recorded as a reduction to other operating expenses within the non-utility operating expenses section of the Condensed Consolidated Statements of Income. There is no admission of wrongdoing on the part of the settling parties and no part of the refund payment by Avista Energy constitutes a fine or a penalty. The settlement resolves all claims for alleged overcharges in the California Refund Proceeding, and in the Pacific Northwest Refund Proceeding (for sales made to CERS). The settlement also includes settlement of the Trading Investigation, the Bidding Investigation and the California Attorney General Complaint (the "Lockyer Complaint"). The settlement was approved by the FERC and is final so there is no longer any potential liability.

California Attorney General Complaint (the "Lockyer Complaint")

In May 2002, the FERC dismissed a complaint filed in March 2002 by the California AG that alleged violations of the FPA by the FERC and all sellers (including Avista Corp. and its subsidiaries) of electric power and energy into California. The complaint alleged that the FERC's implementation of market-based rate authority was flawed and, as a result, individual sellers should refund the difference between the rate charged and a just and reasonable rate. In May 2002, the FERC issued an order dismissing the complaint. In September 2004, the Ninth Circuit upheld the FERC's market-based rate authority, but held that the FERC erred in ruling that it lacked authority to order refunds for violations of its reporting requirement. The Court remanded the case for further proceedings, which ultimately resulted in summary disposition at the FERC in favor of Avista Utilities and Avista Energy. The proceeding is now before the Ninth Circuit.

On March 7, 2014, Avista Utilities, Avista Energy and the California Parties filed a settlement at the FERC that resolves this matter. The settlement was approved by the FERC and is final so there is no longer any potential liability.

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. The Plaintiffs request that the Court grant injunctive and declaratory relief, 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.

On May 3, 2013, the Colstrip Owners filed a Partial Motion to Dismiss, seeking dismissal of 36 of the 39 claims.

On September 12, 2013, the Plaintiffs filed Plaintiffs' First Motion for Partial Summary Judgment on the Applicable Method for Calculating Emission Increases from Modifications Made to the Colstrip Power Plant.

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. The Plaintiffs request that the Court grant injunctive and declaratory relief, order remediation of alleged environmental damage, 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 Colstrip Owners filed a Motion to Dismiss, seeking dismissal of all of Plaintiffs' claims contained in the Amended Complaint.

On May 22, 2014, the Magistrate Judge filed his Findings and Recommendations as to the motions and recommended that 1) the Colstrip Owners' Motion to Dismiss be granted as to the Plaintiffs' Best Available Control Technology claims and the injunctive relief sought regarding two of the claims, but denied the Motion in all other respects; and 2) the Plaintiffs' Motion for Partial Summary Judgment be denied.

Plaintiffs' have filed Objections to Findings and Recommendations of Magistrate Judge and the Colstrip Owners have filed their response to Plaintiffs' objections.

On April 9, 2014, the Court issued an Order revising the Scheduling Order and setting the trial date for June 8, 2015.

Due to the preliminary nature of the lawsuit, Avista Corp. cannot, at this time, predict the outcome of the matter.

Spokane River Licensing

The Company owns and operates six hydroelectric plants on the Spokane River. Five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls) are regulated under one 50-year FERC license issued in June 2009 and are referred to as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. The license incorporated the 4(e) conditions that were included in the December 2008 Settlement Agreement with the United States Department of Interior and the Coeur d'Alene Tribe, as well as the mandatory conditions that were agreed to in the Idaho 401 Water Quality Certifications and in the amended Washington 401 Water Quality Certification.

As part of the Settlement Agreement with the Washington Department of Ecology (Ecology), the Company has participated in the Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On May 20, 2010, the EPA approved the TMDL and on May 27, 2010, Ecology filed an amended 401 Water Quality Certification with the FERC for inclusion into the license. The amended 401 Water Quality Certification includes the Company's level of responsibility, as defined in the TMDL, for low dissolved oxygen levels in Lake Spokane. The Company submitted a draft Water Quality Attainment Plan for Dissolved Oxygen to Ecology in May 2012 and this was approved by Ecology in September 2012. This plan was subsequently approved by the FERC. The Company began implementing this plan in 2013, and management believes costs will not be material. On July 16, 2010, the City of Post Falls and the Hayden Area Regional Sewer Board filed an appeal with the United States District Court for the District of Idaho with respect to the EPA's approval of the TMDL. The Company, the City of Coeur d'Alene, Kaiser Aluminum and the Spokane River Keeper subsequently moved to intervene in the appeal. In September 2011, the EPA issued a stay to the litigation that will be in effect until either the permits are issued and all appeals and challenges are complete or the court lifts the stay. The stay is still in effect.

During 2013, through a collaborative process with key stakeholders, a decision was reached to not move forward with a specific capital project to add oxygen to Lake Spokane. At the time of such decision, the Company had expended $1.3 million on the discontinued project. On September 26, 2013 and October 23, 2013, the UTC and IPUC, respectively, issued Orders approving the Company's petition for an accounting order authorizing deferral of costs related to the discontinued project. The Washington portion of the project costs were $0.9 million and the Idaho portion were $0.5 million and these costs have been recorded as regulatory assets. The Company has included the Washington portion of the costs in the latest general rate case filing and the Company currently intends to seek recovery of the Idaho costs through future ratemaking procedures.

The UTC and IPUC approved the recovery of licensing costs through the general rate case settlements in 2009. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to implementing the license for the Spokane River Project.

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 have been 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. 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.

In January 2010, the USFWS revised its 2005 designation of critical habitat for the bull trout to include the lower Clark Fork River as critical habitat. 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

On December 24, 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 from Ecology that Ecology is considering any enforcement action and the Company initiated a voluntary cleanup action with the installation of a recovery system.

As of June 30, 2014, 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 agreement with the International Brotherhood of Electrical Workers represents 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 bargaining unit employees expired in March 2014. A new three-year agreement in Oregon, which covers approximately 50 employees, was approved in April 2014. Negotiations are currently ongoing with respect to the expired labor agreement in Washington and Idaho and the Company does not expect any disruption to its operations.

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 13. 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. Ecova was a provider of facility information and cost management services for multi-site customers throughout North America. The Ecova business segment has been disposed of as of June 30, 2014. All income statement amounts have been 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, we completed our acquisition of AERC and going forward, this will be considered a separate reportable business segment.

The following table presents information for each of the Company’s business segments (dollars in thousands):

	Avista Utilities	Other	Intersegment Eliminations (1)	Total
For the three months ended June 30, 2014:				
Operating revenues	$ 303,555	$ 9,475	$ (450)	$ 312,580
Resource costs	128,922	—	—	128,922
Other operating expenses	67,349	1,330	(450)	68,229
Depreciation and amortization	31,180	151	—	31,331
Income from operations	54,737	7,994	—	62,731
Interest expense (2)	18,422	316	(79)	18,659
Income taxes	13,302	3,389	—	16,691
Net income from continuing operations attributable to Avista Corp. shareholders	26,685	4,490	79	31,254
Capital expenditures (3)	76,789	56	—	76,845
For the three months ended June 30, 2013:				
Operating revenues	$ 298,169	$ 9,769	$ (450)	$ 307,488
Resource costs	126,511	—	—	126,511
Other operating expenses	65,784	9,865	(450)	75,199
Depreciation and amortization	29,025	175	—	29,200
Income (loss) from operations	55,240	(270)	—	54,970
Interest expense (2)	19,028	603	(76)	19,555
Income taxes	14,553	(243)	—	14,310
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	24,568	(432)	76	24,212
Capital expenditures (3)	74,699	90	—	74,789
For the six months ended June 30, 2014:				
Operating revenues	$ 741,129	$ 18,929	$ (900)	$ 759,158
Resource costs	349,419	—	—	349,419
Other operating expenses	134,686	11,163	(900)	144,949
Depreciation and amortization	61,906	298	—	62,204
Income from operations	145,605	7,468	—	153,073
Interest expense (2)	36,968	713	(167)	37,514
Income taxes	40,922	3,051	—	43,973
Net income from continuing operations attributable to Avista Corp. shareholders	74,681	3,882	167	78,730
Capital expenditures (3)	136,514	102	—	136,616
For the six months ended June 30, 2013:				
Operating revenues	$ 729,746	$ 19,141	$ (900)	$ 747,987
Resource costs	356,141	—	—	356,141
Other operating expenses	131,228	19,660	(900)	149,988
Depreciation and amortization	56,960	365	—	57,325
Income (loss) from operations	137,991	(883)	—	137,108
Interest expense (2)	37,798	1,276	(153)	38,921
Income taxes	39,333	(771)	—	38,562
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	66,818	(1,539)	153	65,432
Capital expenditures (3)	145,344	115	—	145,459
Total Assets:				
As of June 30, 2014:	$ 4,119,627	$ 82,503	$ —	$ 4,202,130
As of December 31, 2013 (4):	$ 3,940,998	$ 81,282	$ —	$ 4,022,280

(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.
(4) The consolidated total assets presented here as of December 31, 2013 exclude total assets at Ecova of $339.6 million.

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 June 30, 2014, and the related condensed consolidated statements of income and comprehensive income for the three-month and six-month periods ended June 30, 2014 and 2013, and the related condensed consolidated statements of equity and redeemable noncontrolling interests and cash flows for the six-month periods ended June 30, 2014 and 2013. 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, 2013, 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 26, 2014, 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, 2013 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
August 8, 2014

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

Business Segments

We have two reportable business segments as follows:

- **Avista Utilities** – an operating division of Avista Corp. that comprises our regulated utility operations. Avista Utilities generates, transmits and distributes electricity and distributes natural gas, serving electric and gas customers in eastern Washington and northern Idaho and gas customers in parts of Oregon. The utility also engages in wholesale purchases and sales of electricity and natural gas.
- **Ecova** – was an 80.2 percent owned indirect subsidiary of Avista Corp. prior to its disposition on June 30, 2014. Ecova provided energy efficiency and cost management programs and services for multi-site customers and utilities throughout North America. Ecova's service lines include expense management services for utility and telecom needs as well as strategic energy management and efficiency services that include procurement, conservation, performance reporting, financial planning, facility optimization and continuous monitoring, and energy efficiency program management for commercial enterprises and utilities.

We have other businesses, including sheet metal fabrication, venture fund investments and real estate investments, as well as certain other operations of Avista Capital. 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.

In addition to the above, on July 1, 2014, we completed our acquisition of AERC, and as of that date, AERC is a wholly-owned subsidiary of Avista Corp. In future periods, AERC will be a reportable business segment.

The following table presents net income (loss) attributable to Avista Corp. shareholders for each of our business segments (and the other businesses) for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Avista Utilities	$ 26,685	$ 24,568	$ 74,681	$ 66,818
Ecova - Discontinued operations (1)	69,696	1,521	70,807	2,719
Other	4,490	(432)	3,882	(1,539)
Net income attributable to Avista Corporation shareholders	$ 100,871	$ 25,657	$ 149,370	$ 67,998

(1) The results for the quarter and six months ended June 30, 2014 include the net gain on sale of Ecova of approximately $68.1 million.

Executive Level Summary

Overall Results

Net income attributable to Avista Corporation shareholders was $100.9 million for the three months ended June 30, 2014, an increase from $25.7 million for the three months ended June 30, 2013. For the six months ended June 30, 2014, net income attributable to Avista Corporation shareholders was $149.4 million, an increase from $68.0 million for the six months ended June 30, 2013. The increase in both quarter-to-date and year-to-date earnings was primarily due to the disposition of Ecova on June 30, 2014, which resulted in the recognition of a $68.1 million net gain. In addition, we recognized a $9.8 million net gain at Avista Energy during the second quarter related to the settlement of the California power markets litigation. The net gain from the litigation settlement was partially offset by a pre-tax contribution of $6.4 million of the proceeds to the Avista Foundation, a charitable organization funded by Avista Corp. We also had increased earnings at Avista Utilities primarily due to the implementation of general rate increases in all our jurisdictions. Our utility earnings benefited from colder weather during the first quarter, which were partially offset in the second quarter by milder weather and expected increases in other operating expenses, depreciation and amortization and taxes other than income taxes. Utility results for 2013 also included the net benefit from the settlement with the Bonneville Power Administration. These results, including a quantification of their respective impacts, are discussed in detail below under "Results of Operations."

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, 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. The following are the recent general rate increases that have occurred or will go into effect in the near future:

Jurisdiction	Service	Effective Date
Washington	Electric and Natural Gas	January 1, 2013 (1) (3)
	Electric and Natural Gas	January 1, 2014 (1) (3)
Idaho	Natural Gas	April 1, 2013 (2) (3) (4)
	Electric and Natural Gas	October 1, 2013 (2) (3) (4)
Oregon	Natural Gas	February 1, 2014 (5)
	Natural Gas	November 1, 2014 (5)

(1) Relates to a settlement agreement in our Washington general rate cases (originally filed on April 2, 2012), which was approved by the UTC in December 2012 (see further discussion below under "Washington General Rate Cases").

(2) Relates to a settlement agreement in our Idaho general rate cases (originally filed on October 11, 2012), which was approved by the IPUC in March 2013 (see further discussion below under "Idaho General Rate Cases").

(3) Included in the original settlement agreements is a provision that we will not file a general rate case in these jurisdictions seeking new rates to take effect before January 1, 2015. We filed general rate cases in Washington in February 2014 with proposed rates that would take effect on or after January 1, 2015. This provision does not preclude us from filing other rate adjustments such as PGAs.

(4) On July 14, 2014, we reached a settlement agreement with all interested parties for a one-year extension to our current rate plan, which was set to expire on December 31, 2014. Under the proposed extension, base retail rates would remain unchanged through December 31, 2015. The settlement agreement was filed with the IPUC for approval. There is no statutory period within which the IPUC must review the settlement and issue a decision; however, we expect the IPUC to issue an Order regarding the settlement before the end of 2014. See further discussion below under "Idaho General Rate Cases".

(5) Relates to a settlement agreement in our Oregon general rate case (originally filed in August 2013), which was approved by the OPUC in January 2014. In addition, we are evaluating the need to file a natural gas general rate case and we anticipate filing a case in the second half of 2014. See further discussion below under "Oregon General Rate Case."

In addition to the above, AEL&P, based in Juneau, Alaska (discussed below) is currently anticipating filing an electric general rate case with the Regulatory Commission of Alaska (RCA) in the second half of 2014.

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' capital expenditures were $136.5 million for the six months ended June 30, 2014. We expect Avista Utilities' capital expenditures to be about $355 million for 2014, $355 million in 2015 and $350 million in 2016. The $20 million increase in estimated Avista Utilities' capital expenditures for 2014 relates to the replacement of our customer information system and work management systems. We expect to spend approximately $6 million for 2014 and $15 million for each of 2015 and 2016 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 completed our acquisition of AERC, based in Juneau, Alaska. As of July 1, 2014 AERC is a wholly-owned subsidiary of Avista Corp.

The primary subsidiary of AERC is AEL&P, a regulated utility which provides electric services to approximately 16,000 customers in the City and Borough of Juneau, Alaska. In 2013, AEL&P had annual revenues of $42.6 million and a total rate base of $109 million, based on the 2013 test year. For the first six months of 2014, AERC had revenues of $24.5 million, none of which were recognized by Avista Corp. The utility has a firm retail peak load of approximately 68 MW. AEL&P owns four hydroelectric generating facilities, having a total present capacity of 24.7 MW, and has a power purchase commitment for the output of the Snettisham hydroelectric project, having a present capacity of 78 MW, for a total hydroelectric capacity of 102.7 MW. AEL&P is not interconnected to any other electric system. The utility also has 93.9 MW of diesel generating capacity to provide back-up service to firm customers when necessary.

In addition to the regulated utility, AERC owns 100 percent of AJT Mining, which is an inactive mining company holding certain properties.

In connection with the closing, we issued 4.5 million new shares of common stock to the shareholders of AERC at a price of $32.46 per share, which reflects a purchase of $170 million, plus acquired cash, less outstanding debt and other closing adjustments.

We made $4.7 million in cash payments to acquire AERC during the first half of 2014 and we have recorded these amounts to other deferred charges as of June 30, 2014. On July 1, 2014, at the completion of the acquisition of AERC, these cash payments are part of the purchase consideration paid for AERC.

We expect this transaction to result in the recording of approximately $51 million in goodwill during the third quarter of 2014.

In AEL&P's most recent general rate case the RCA approved a capital structure including 53.8 percent equity and an authorized return on equity of 12.875 percent. We expect that AEL&P will maintain a similar capital structure going forward. The consolidated capital structure of AERC is expected to be similar to the capital structure of Avista Corp.

For additional information regarding the AERC transaction, see "Note 4 of the Notes to Condensed Consolidated Financial Statements," our Current Report on Form 8-K dated November 4, 2013 and our Current Report on Form 8-K dated June 30, 2014.

Ecova Disposition

On May 29, 2014, Avista Capital, Inc., our non-regulated subsidiary, entered into a definitive agreement to sell its interest in Ecova to Cofely USA Inc., an indirect subsidiary of GDF SUEZ, a French multinational utility company. The sales transaction was completed on June 30, 2014 for a sales price of $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 we 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 $16.75 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 $1.5 million will be held in escrow pending resolution of adjustments to working capital (which is expected to occur before the end of 2014).

Avista Capital and Cofely USA Inc. agreed to make an election under Internal Revenue 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 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 $133.2 million and result in a net gain of $68.1 million. The Company expects to receive the full amount of its portion of the escrow accounts; therefore, the full amounts are included in the gain calculation.

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 (see further discussion below).

Stock Repurchase Program

On June 13, 2014, our Board of Directors approved the repurchase of up to 4 million shares of the Company's outstanding common stock. Repurchases of common stock commenced on July 7, 2014 and will not continue past December 31, 2014. We can also choose to terminate the repurchase program before December 31, 2014. Repurchases are made in the open market or in privately negotiated transactions. There is no assurance that the goal of repurchasing 4 million shares will be achieved. Through July 31, 2014, we repurchased 292,100 shares at a total cost of $9.4 million and an average cost of $32.28 per share. All repurchased shares revert to the status of authorized but unissued shares.

California Power Markets Litigation Settlement and Avista Foundation Charitable Contribution

On June 23, 2014, Avista Energy (an unregulated indirect subsidiary of Avista Corp.) received $15.0 million in settlement proceeds from the completion of a litigation settlement with various California parties. The litigation was related to the prices paid for power in the California spot markets during the years 2000 and 2001. This resulted in Avista Energy recognizing an increase in pre-tax earnings of approximately $15.0 million, which was recorded as a reduction to other operating expenses within the non-utility operating expenses section of the Condensed Consolidated Statements of Income. See "Note 12 of the Notes to the Condensed Consolidated Financial Statements" for further information regarding this litigation settlement.

Subsequent to the receipt of the settlement proceeds, we contributed approximately $6.4 million of the proceeds to the Avista Foundation and the remainder of the proceeds will be used to fund current operations and possibly pay down outstanding debt.

Liquidity and Capital Resources

During the second quarter of 2014, we received cash proceeds of $205.4 million from the Ecova sale and we expect to receive additional proceeds of $13.6 million from the escrow accounts related to the sale ($1.1 million in 2014 and $12.5 million in 2015). We also received $15.0 million from the California power markets litigation settlement. We used the above funds to pay off the outstanding balance owed on our committed line of credit on July 1, 2014 of $151.5 million, we contributed $6.4 million to the Avista Foundation and we initiated a common stock share repurchase program for up to 4 million shares during the second half of 2014 (discussed below). We expect to borrow funds from our committed line of credit later during the third quarter of 2014 because we expect to make tax payments of $85.8 million associated with the sale of Ecova and we will need additional funds to complete our stock repurchase program.

We have a committed line of credit with various financial institutions in the total amount of $400.0 million. In April 2014, we amended this committed line of credit agreement to extend the expiration date to April 2019. The amendment also provides us with the option to request an extension for an additional one or two years beyond April 2019, provided there is no event of default prior to the requested extension and the requested extension does not cause the remaining term until the expiration date to exceed five years. The amendment did not change the amount of the committed line of credit. As of June 30, 2014, there were $151.5 million of cash borrowings and $21.9 million in letters of credit outstanding leaving $226.6 million of available liquidity under this line of credit. However, as discussed above, on July 1, 2014, we paid off the outstanding cash borrowing balance of this committed line of credit agreement.

AEL&P has a committed line of credit in the amount of $14.5 million with an expiration date of June 2015. As of June 30, 2014, there are no borrowings outstanding under this committed line of credit.

We expect to issue approximately $165.0 million of long-term debt during 2014, including about $90.0 million of debt issuances combined between AERC and AEL&P associated with rebalancing the consolidated capital structure at AERC. In July 2014, AEL&P entered into a bond purchase agreement with two institutional investors in the private placement market for the purpose of issuing $75.0 million of 4.54 percent first mortgage bonds due in 2044. The new first mortgage bonds will be issued under and in accordance with the AEL&P mortgage and Deed of Trust, dated as of July 1, 2014, from AEL&P to U.S. Bank, N.A., trustee. The issuance of the bonds will occur at closing in September 2014. In addition to the first mortgage bonds, we expect to issue $15.0 million in term loans at AERC during the third quarter of 2014. We acquired AERC primarily by issuing Avista Corp. common stock; therefore the proceeds from the new AERC and AEL&P debt will be used to repay approximately $38.0 million of existing AEL&P debt and the remainder of the proceeds will be paid as a cash dividend up to Avista Corp. The issuance of long-term debt of $75.0 million at Avista Corp. will be used primarily to fund Avista Utilities' capital expenditures and other contractual commitments.

We are party to two sales agency agreements for the sale from time to time of shares of our common stock; however, we do not plan to issue any shares under these agreements during 2014 due to the AERC transaction.

In the six months ended June 30, 2014, we issued $2.0 million (net of issuance costs) of common stock under the dividend reinvestment and direct stock purchase plan, and employee plans. On July 1, 2014, we issued 4.5 million shares of common stock at a total fair value of approximately $150 million related to closing the AERC transaction. We do not expect to issue any additional shares for 2014, other than those under the dividend reinvestment and direct stock purchase plan, and employee plans.

On July 7, 2014, we commenced a stock repurchase program to repurchase up to 4 million shares of our outstanding common stock. The program will not continue past December 31, 2014 and we have the option to terminate the program before that date.

Included in our 2014 liquidity estimates is approximately $50.0 million of lower tax payments (exclusive of any amount of taxes payable on the Ecova sales transaction) due to the planned adoption of federal tax tangible property regulations. This will be accomplished through an accounting method change filing with the Internal Revenue Service that will retroactively modify which tangible property transactions we expense versus capitalize and depreciate for federal tax purposes. We have engaged a third party specialist to evaluate our proposed accounting method change filing and the estimated tax savings.

After considering the expected issuances of long-term debt and the actual issuances of common stock during 2014, the lower tax payments from the adoption of the federal tax tangible property regulations and the proceeds from the litigation settlement and Ecova disposition, we expect net cash flows from operating activities, together with cash available under our $400.0 million committed line of credit agreement, to provide adequate resources to fund capital expenditures, dividends, and other contractual commitments.

Avista Utilities – 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

2011 General Rate Cases

A settlement agreement approved by the UTC in December 2011 regarding electric and natural gas general rate cases filed in May 2011 provided for the deferral of certain generation plant maintenance costs. For 2011 and 2012 the Company compared actual, non-fuel, maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of baseline maintenance expenses used to establish base retail rates, and deferred the difference. This deferral occurred each year, with no carrying charge, with deferred costs to be amortized over a four-year period, beginning in the year following the period costs were deferred. Total net deferred costs under this mechanism in Washington were a regulatory asset of $2.6 million as of June 30, 2014 compared to $3.1 million as of December 31, 2013. As part of the settlement agreement to our latest general rate case approved in December 2012, the parties agreed to terminate the maintenance cost deferral mechanism on December 31, 2012, with the four-year amortization of the 2011 and 2012 deferrals to conclude in 2015 and 2016, respectively.

2012 General Rate Cases

In December 2012, the UTC approved a settlement agreement in our electric and natural gas general rate cases filed in April 2012. The settlement, effective January 1, 2013, provided that base rates for our Washington electric customers increase by an overall 3.0 percent (designed to increase annual revenues by $13.6 million), and base rates for our Washington natural gas customers increase by an overall 3.6 percent (designed to increase annual revenues by $5.3 million). Under the settlement, there was a one-year credit designed to return $4.4 million to electric customers from the existing ERM deferral balance so the net average electric rate increase to our customers in 2013 was 2.0 percent. The credit to customers from the ERM balance did not impact our earnings.

The approved settlement also provided that, effective January 1, 2014, base rates increased for our Washington electric customers by an overall 3.0 percent (designed to increase annual revenues by $14.0 million), and for our Washington natural gas customers by an overall 0.9 percent (designed to increase annual revenues by $1.4 million). The settlement provides for a one-year credit designed to return $9.0 million to electric customers from the ERM deferral balance, so the net average electric rate increase to our customers effective January 1, 2014 was 2.0 percent. The credit to customers from the ERM balance will not impact our earnings. The ERM balance as of June 30, 2014 was a liability of $16.7 million.

The settlement agreement provides for an authorized return on equity (ROE) of 9.8 percent and an equity ratio of 47 percent, resulting in an overall rate of return on rate base of 7.64 percent.

The December 2012 UTC Order approving the settlement agreement included certain conditions.

(1) The new retail rates that became effective on January 1, 2014 are temporary rates, and on January 1, 2015, electric and natural gas base rates will revert back to 2013 levels absent any intervening action from the UTC. The original settlement agreement has a provision that we will not file a general rate case in Washington seeking new rates to take effect before January 1, 2015. We filed general rate cases in Washington in February 2014 with proposed rates that would take effect on or after January 1, 2015 (see further discussion below).

(2) In its Order, the UTC found that much of the approved base rate increase is justified by the planned capital expenditures necessary to upgrade and maintain our utility facilities. If these capital projects are not completed to a level that was contemplated in the settlement agreement, this could result in base rates which are considered too high by the UTC. We are required to file capital expenditure progress reports with the UTC on a periodic basis so that the UTC can monitor the capital expenditures and ensure they are in line with those contemplated in the settlement agreement. Total utility capital expenditures among all jurisdictions were $294.4 million for 2013. We expect utility capital expenditures to be about $355 million for 2014, and $355 million for 2015, which are above the capital expenditures contemplated in the settlement agreement.

2014 General Rate Cases

On February 4, 2014 we filed electric and natural gas general rates cases with the UTC. We have requested an overall increase in base electric rates of 3.8 percent (designed to increase annual electric revenues by $18.2 million) and an overall increase in base natural gas rates of 8.1 percent (designed to increase annual natural gas revenues by $12.1 million). Our requests are based on a proposed overall rate of return of 7.71 percent, with a common equity ratio of 49.0 percent and a 10.1 percent ROE.

We have also proposed a rebate beginning January 1, 2015, related to our sale of renewable energy credits (REC) that would reduce customers' monthly electric bills by 1.1 percent. The rebate associated with the sale of RECs is in response to the UTC Order approving our previous general rate case settlement in December 2012. This proposed REC rebate would commence simultaneously with the expiration of two rebates that, together, are currently reducing customers' monthly electric bills by 2.8 percent. The net effect, commencing January 1, 2015, of the proposed new 1.1 percent rebate and the expiration of the current 2.8 percent rebate would be an increase in monthly electric bills of approximately 1.7 percent from 2014 levels. These rebates do not increase or decrease our earnings.

The combination of the 3.8 percent requested increase in base electric rates and the effective 1.7 percent increase attributable to the rebates would be a 5.5 percent increase in electric billings.

As part of our electric and natural gas general rate case filings, we have requested the implementation of decoupling mechanisms, which would to some extent sever the link between actual volumetric sales and the recovery of our fixed costs. Under the proposed decoupling mechanisms, the under- (or over-) recovery of fixed costs would be deferred and, subject to UTC prudency review, surcharged (or rebated) to customers over a one-year period.

The proposed mechanisms would be subject to an annual earnings test which proposes that if our actual annual rate of return exceeds the most recently authorized rate of return for our Washington electric and natural gas operations, the amount of a proposed surcharge is reduced or eliminated to reduce the actual rate of return toward the Commission-authorized level. In addition, the mechanisms would be subject to an annual rate increase limitation which would prevent the amount of the incremental proposed rate adjustments under the mechanisms from exceeding a 3 percent rate increase for each of electric and natural gas operations.

The UTC has up to 11 months to review the filings and issue a decision.

Idaho General Rate Cases

2011 General Rate Cases

A settlement agreement approved by the IPUC in September 2011 regarding electric and natural gas general rate cases filed in July 2011 provided for the deferral of certain generation plant operation and maintenance costs. In order to address the variability in year-to-year operation and maintenance costs, beginning in 2011, we are deferring certain changes in operation and maintenance costs related to the Coyote Springs 2 natural gas-fired generation plant and our 15 percent ownership interest in Units 3&4 of the Colstrip generation plant. We compare actual, non-fuel, operation and maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of expenses authorized for recovery in base rates in the applicable deferral year, and defer the difference from that currently authorized. The deferral occurs annually, with no carrying charge, with deferred costs being amortized over a three-year period, beginning in the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases will be the actual operation and maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. Total net deferred costs under this mechanism in Idaho were regulatory assets of $3.0 million as of June 30, 2014 and $2.8 million as of

December 31, 2013.

2012 General Rate Cases

In March 2013, the IPUC approved a settlement agreement in our electric and natural gas general rate cases filed in October 2012. As agreed to in the settlement, new rates were implemented in two phases: April 1, 2013 and October 1, 2013. Effective April 1, 2013, base rates increased for our Idaho natural gas customers by an overall 4.9 percent (designed to increase annual revenues by $3.1 million). There was no change in base electric rates on April 1, 2013. However, the settlement agreement provided for the recovery of the costs of the Palouse Wind Project through the PCA mechanism, subject to the 90 percent customers/10 percent Company sharing ratio, until these costs are reflected in base retail rates in our next general rate case.

The settlement also provided that, effective October 1, 2013, base rates increased for our Idaho natural gas customers by an overall 2.0 percent (designed to increase annual revenues by $1.3 million). A credit resulting from deferred natural gas costs of $1.6 million is being returned to our Idaho natural gas customers from October 1, 2013 through December 31, 2014, so the net annual average natural gas rate increase to natural gas customers effective October 1, 2013 was 0.3 percent.

Further, the settlement provided that, effective October 1, 2013, base rates increased for our Idaho electric customers by an overall 3.1 percent (designed to increase annual revenues by $7.8 million). A $3.9 million credit resulting from a payment made to us by the Bonneville Power Administration relating to its prior use of our transmission system is being returned to Idaho electric customers from October 1, 2013 through December 31, 2014, so the net annual average electric rate increase to electric customers effective October 1, 2013 was 1.9 percent.

The $1.6 million credit to Idaho natural gas customers and the $3.9 million credit to Idaho electric customers do not impact our net income.

The settlement agreement provides for an authorized ROE of 9.8 percent and an equity ratio of 50.0 percent.

The settlement also includes an after-the-fact earnings test for 2013 and 2014, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earns more than a 9.8 percent ROE, we will share with customers 50 percent of any earnings above the 9.8 percent. In 2013, our returns exceeded this level and we deferred for future ratemaking treatment $3.9 million for Idaho electric customers and $0.4 million for Idaho natural gas customers. Of the electric deferral amount, $2.0 million was recorded in 2013 and $1.9 million was recorded in the first quarter of 2014 based on a revision of the allocation of costs between Idaho and Washington for regulatory purposes. The ratemaking treatment for these deferrals is addressed in the 2014 rate plan extension request explained below.

The settlement agreement allows us to file a general rate case in Idaho in 2014; however, new rates resulting from the filing would not take effect prior to January 1, 2015. This provision does not preclude us from filing other rate adjustments such as the PGA.

2014 Rate Plan Extension Request

On July 14, 2014, we filed a settlement agreement with the IPUC, which reflects agreement among all interested parties, for a one-year extension to our current rate plan (2012 general rate cases), which was set to expire on December 31, 2014. Under the proposed extension, base retail rates would remain unchanged through December 31, 2015.

The settlement agreement comes after discussions regarding our retail rates in Idaho.

- On March 24, 2014, we filed a notice with the IPUC that we intended to file a combined electric and natural gas general rate case on or after June 2, 2014.
- Subsequently, we had informal discussions with all parties to our last general rate case regarding a possible one-year extension of the existing rate plan from January 1, 2015 to January 1, 2016.
- We made a request to the IPUC on May 30, 2014 to initiate settlement discussions and the IPUC issued an order on June 11, 2014, which, among other things, set a settlement conference for June 25, 2014.
- The parties subsequently entered into a settlement stipulation, including terms and conditions for a one-year extension of the current rate plan, from January 1, 2015 to January 1, 2016.

The proposed settlement would 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 (described above under "2011 General Rate Cases") from 2015 to 2016 and

- deferred accounting, for later review and recovery, of the majority of the costs associated with the replacement of our customer information and work management systems, which we plan to complete in the first half of 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 would be allowed to use any 2014 Idaho after-the-fact earnings test deferral (described above under "2012 General Rate Cases") to support an actual earned ROE in 2015 up to 9.5 percent. As of June 30, 2014, we have deferred a total of $1.2 million for the 2014 after-the-fact earnings test, which represents our estimate for the six months ended June 30, 2014. During 2015, if we earn more than the 9.8 percent ROE, 50 percent of the earnings above 9.8 percent would 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 proposed settlement would replace two rebates, set to expire on January 1, 2015, that are currently reducing customers' monthly energy bills by 1.3 percent on the electric side and 1.7 percent on the natural gas side. The rebates would be replaced for a one-year period, through December 31, 2015, using existing deferral balances due to customers, which would have no impact on net income. This provision does not preclude us from filing other rate adjustments such as the PGA.

The settlement agreement was filed with the IPUC on July 14, 2014 and there is no statutory period within which the IPUC must review the settlement and issue a decision; however, we expect the IPUC to issue an Order regarding the settlement before the end of 2014.

Oregon General Rate Cases

2013 General Rate Case

On January 21, 2014, the OPUC approved a settlement agreement to our natural gas general rate case (originally filed in August 2013). As agreed to in the settlement, new rates will be 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 our customer information system replacement and the actual costs incurred through September 30, 2014, and the actual costs incurred through June 30, 2014 related to our Aldyl A distribution pipeline replacement program. As noted elsewhere, the replacement of our customer information and work management systems is expected to be completed during the first half of 2015. The November 1, 2014 rate increase is expected to be reduced from $1.4 million to $0.3 million due to the delay in the implementation of the customer information system replacement.

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.

Potential 2014 General Rate Case

We are evaluating the need to file a natural gas general rate case in Oregon and our expectation is to file a case in the second half of 2014.

Alaska General Rate Case

AEL&P is anticipating filing an electric general rate case with the RCA in the second half of 2014.

Bonneville Power Administration Reimbursement and Reardan Wind Generation Project

In May 2013, the UTC approved our Petition for an order authorizing certain accounting and ratemaking treatment related to two issues. The first issue related to transmission revenues associated with a settlement between Avista Corp. and the Bonneville Power Administration (BPA), whereby the BPA reimbursed the Company $11.7 million in the first quarter of 2013 for the BPA's past use of our transmission system. The second issue related to $4.3 million of costs we incurred over the past several years for the development of a wind generation project site near Reardan, Washington, which has been terminated. The UTC authorized us to retain $7.6 million of the BPA settlement payment in 2013, representing the entire portion of the settlement allocable to our Washington business. However, this amount was deemed to first reimburse the Company for the $2.5 million of Reardan project costs that are allocable to our Washington business, leaving $5.1 million retained for the benefit of shareholders in 2013.

The BPA agreed to pay $3.2 million annually for the future use of our transmission system. We are separately tracking and deferring for the customers' benefit, the Washington portion of these revenue payments in 2013 and 2014 ($2.1 million annually). We implemented a one-year $4.2 million rate decrease for customers effective January 1, 2014 to partially offset our electric general rate increase effective January 1, 2014. To the extent actual revenues from the BPA in 2013 and 2014 differ from those refunded to customers in 2014, the difference will be added to or subtracted from the ERM balance. In Idaho, under the terms of the approved rate case settlement, 90 percent of the portion of the BPA settlement allocable to our Idaho business ($4.1 million) is being credited back to customers over 15 months, beginning October 2013, and we are amortizing the Idaho portion of Reardan costs ($1.7 million, including $1.3 million of incurred costs and $0.4 million of equity-related AFUDC) over a two-year period, beginning April 2013.

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to our 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 $4.9 million as of June 30, 2014 and a liability of $12.1 million as of December 31, 2013.

The following PGAs went into effect in our various jurisdictions during 2013. No PGAs have gone into effect for the first six months of 2014.

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

(1) As it relates to the 2012 Oregon PGA, we requested that the PGA be implemented in two steps. The first step, implemented on November 1, 2012, was a decrease of 7.5 percent. The second step was an additional decrease of 0.8 percent, effective on January 1, 2013, to provide customers the net savings related to our purchase of the Klamath Falls Lateral transmission pipeline.

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used to track certain differences between 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 $16.7 million as of June 30, 2014, compared to a liability of $17.9 million as of December 31, 2013, and these deferred power cost balances represent amounts due to customers. As part of the approved Washington general rate case settlement in December 2012, during 2013 there was a one-year credit designed to return $4.4 million to electric customers from the ERM deferral balance to reduce the net average electric rate increase impact to customers in 2013. Additionally, during 2014 there is a one-year credit designed to return $9.0 million to electric customers from the ERM deferral balance, so the net average electric rate increase impact to customers effective January 1, 2014 was also reduced. The credits to customers from the ERM balances do not impact our net income.

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),
- the net value from optimization activities related to our generating resources, and
- retail loads.

Under the ERM, we absorb the cost or receive 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 currently $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, we make 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, 2014 and as part of the UTC staff's review of this latest annual filing, the staff reviewed the prudence of the Colstrip outage from July 2013 through January 2014. UTC staff found no imprudence by Avista Corp. related to the Colstrip outage and recommended approval of all the ERM related transactions for 2013. The ERM provides for a 90-day review period for the filing; however, the period may be extended by agreement of the parties or by UTC order. The 2013 ERM deferred power costs transactions were approved by an order from the UTC.

We have 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 $7.0 million as of June 30, 2014 compared to an asset of $5.1 million as of December 31, 2013.

Results of Operations

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, Ecova 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 have been 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. For our discussion of discontinued operations and Ecova, see "Item 2. Management's Discussion and Analysis: Ecova - Discontinued Operations."

Three months ended June 30, 2014 compared to the three months ended June 30, 2013

Utility revenues increased $5.4 million, after elimination of intracompany revenues of $28.4 million for the second quarter of 2014 and $31.9 million for the second quarter of 2013. Including intracompany revenues, electric revenues decreased $12.5 million and natural gas revenues increased $14.4 million. Retail electric revenues increased $1.0 million primarily due to general rate increases and a change in revenue mix, with a greater percentage of retail revenue from residential and commercial customers, partially offset by milder weather. Wholesale electric revenues decreased $1.3 million due to a decrease in sales volumes partially offset by an increase in sales prices while sales of fuel decreased $11.5 million. Retail natural gas revenues increased $1.4 million due to higher rates (from PGAs and general rate increases), partially offset by a decrease in volumes (due to milder weather), while wholesale natural gas revenues increased $13.5 million due to an increase in prices and volumes.

Utility resource costs increased $2.4 million, after elimination of intracompany resource costs of $28.4 million for the second quarter of 2014 and $31.9 million for second quarter of 2013. Including intracompany resource costs, electric resource costs decreased $14.7 million and natural gas resource costs increased $13.6 million. The decrease in electric resource costs was primarily due to a decrease in purchased power, fuel for generation and other fuel costs (represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation as part of the resource optimization process), partially offset by an increase in other regulatory amortizations. The decrease in electric resource costs was also partially due to increased hydroelectric generation in the current year. The increase in natural gas resource costs was primarily due to an increase in natural gas purchased.

Utility other operating expenses increased $1.6 million and was the result of increased generation, transmission and distribution operating and maintenance expenses and increased outside services and dues and donations. There were also transaction fees associated with the AERC acquisition of $0.2 million in the second quarter of 2014. These were partially offset by a decrease in pension and other post-retirement benefits expense.

Utility depreciation and amortization increased $2.2 million driven by additions to utility plant.

Utility taxes other than income taxes decreased $0.2 million primarily due to decreased franchise fee taxes, partially offset by increased state excise, municipal and property related taxes.

Other non-utility operating expenses decreased $8.5 million primarily due to the receipt of $15.0 million related to the settlement of the California power markets litigation, partially offset by a $6.4 million contribution to the Avista Foundation.

Interest expense decreased $0.9 million primarily due to the long-term debt outstanding during the second quarter of 2014 having a lower interest rate than the long-term debt outstanding during the second quarter of 2013.

Income taxes increased $2.4 million and our effective tax rate was 34.8 percent for the second quarter of 2014 compared to 37.1 percent for the second quarter of 2013. The increase in expense was primarily due to an increase in income before income taxes. The decrease in the effective tax rate was the result of a Section 199 deduction during the current quarter.

Six months ended June 30, 2014 compared to the six months ended June 30, 2013

Utility revenues increased $11.4 million, after elimination of intracompany revenues of $63.3 million for the six months ended June 30, 2014 and $73.3 million for the six months ended June 30, 2013. Including intracompany revenues, electric revenues decreased $25.8 million and natural gas revenues increased $27.2 million. Retail electric revenues increased $11.0 million primarily due to general rate increases and a change in revenue mix, with a greater percentage of retail revenue from residential and commercial customers. Wholesale electric revenues decreased $4.1 million due to a decrease in sales volumes partially offset by an increase in sales prices while sales of fuel decreased $19.1 million. Other electric revenues decreased $10.5 million primarily due to the receipt of $11.7 million of revenue from the BPA in the first quarter of 2013 for past use of our electric transmission system. Retail natural gas revenues increased $13.1 million due to higher rates (from PGAs and general rate increases) and an increase in volumes (due to colder weather in the first quarter), while wholesale natural gas revenues increased $14.3 million due to an increase in prices, partially offset by a decrease in volumes.

Utility resource costs decreased $6.7 million, after elimination of intracompany resource costs of $63.3 million for the six months ended June 30, 2014 and $73.3 million for the six months ended June 30, 2013. Including intracompany resource costs, electric resource costs decreased $37.9 million and natural gas resource costs increased $21.1 million. The decrease in electric resource costs was primarily due to a decrease in purchased power, fuel for generation and other fuel costs (represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation as part of the resource optimization process). The decrease in electric resource costs was also partially due to increased hydroelectric generation in the current year. The increase in natural gas resource costs was primarily due to an increase in natural gas purchased, partially offset by a decrease in natural gas cost amortizations.

Utility other operating expenses increased $3.5 million and was the result of increased generation, transmission and distribution operating and maintenance expenses and increased outside services and dues and donations. There were also transaction fees associated with the AERC acquisition of $0.7 million in the first half of 2014. These were partially offset by a decrease in pension and other post-retirement benefits expense.

Utility depreciation and amortization increased $4.9 million driven by additions to utility plant.

Utility taxes other than income taxes increased $2.1 million primarily due to increased state excise, municipal and property related taxes.

Other non-utility operating expenses decreased $8.5 million primarily due to the receipt of $15.0 million related to the settlement of the California power markets litigation, partially offset by a $6.4 million contribution to the Avista Foundation.

Interest expense decreased $1.4 million primarily due to the long-term debt outstanding during the first half of 2014 having a lower interest rate than the long-term debt outstanding during the first half of 2013.

Income taxes increased $5.4 million and our effective tax rate was 35.8 percent for the first half of 2014 compared to 37.1 percent for the first half of 2013. The increase in expense was primarily due to an increase in income before income taxes. The decrease in the effective tax rate was the result of a Section 199 deduction during the current year.

Avista Utilities

Non-GAAP Financial Measures

The following discussion includes two financial measures that are considered “non-GAAP financial measures,” electric gross margin and natural gas 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 is intended to supplement an understanding of Avista Utilities' 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 June 30, 2014 compared to the three months ended June 30, 2013

Net income for Avista Utilities was $26.7 million for the second quarter of 2014, an increase from $24.6 million for the second quarter of 2013. Avista Utilities' income from operations was $54.7 million for the second quarter of 2014, a decrease from $55.2 million for the second quarter of 2013. The decrease in income from operations was primarily due to expected increases in other operating expenses, depreciation and amortization, and taxes other than income taxes, partially offset by the implementation of general rate increases. Net income increased slightly due to the above fluctuations and decreases in interest expense and income taxes.

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

	Electric		Natural Gas		Intracompany		Total	
	2014	2013	2014	2013	2014	2013	2014	2013
Operating revenues	$ 231,688	$ 244,197	$ 100,279	$ 85,856	$ (28,412)	$ (31,884)	$ 303,555	$ 298,169
Resource costs	84,020	98,719	73,314	59,676	(28,412)	(31,884)	128,922	126,511
Gross margin	$ 147,668	$ 145,478	$ 26,965	$ 26,180	$ —	$ —	$ 174,633	$ 171,658

Avista Utilities' operating revenues increased $5.4 million and resource costs increased $2.4 million, which resulted in an increase of $3.0 million in gross margin. The gross margin on electric sales increased $2.2 million and the gross margin on natural gas sales increased $0.8 million. The increase in electric gross margin was primarily due to general rate increases in Washington and Idaho and lower power supply costs (due in part to increased hydroelectric generation), partially offset by the net benefit from the settlement with the BPA in the prior year and weather that was milder than normal and milder than the prior year, which decreased heating and cooling loads. For the second quarter of 2014, we recognized a pre-tax benefit of $3.6 million under the ERM in Washington compared to a benefit of $1.1 million for the second quarter of 2013. The increase in natural gas gross margin was primarily due to general rate increases, partially offset by milder weather, which decreased heating loads.

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 June 30 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2014	2013	2014	2013
Residential	$ 66,941	$ 65,614	728	747
Commercial	71,810	68,757	765	746
Industrial	27,587	31,018	463	551
Public street and highway lighting	1,892	1,863	7	7
Total retail	168,230	167,252	1,963	2,051
Wholesale	35,597	36,867	1,124	1,363
Sales of fuel	22,029	33,488	—	—
Other	7,069	6,590	—	—
Provision for earnings sharing	(1,237)	—	—	—
Total	$ 231,688	$ 244,197	3,087	3,414

Retail electric revenues increased $1.0 million due to an increase in revenue per MWh (increased revenues $8.7 million), partially offset by a decrease in total MWhs sold (decreased revenues $7.7 million). The increase in revenue per MWh was primarily due to general rate increases and a change in revenue mix, with a greater percentage of retail revenue from residential and commercial customers.

The decrease in total MWhs sold to residential customers was primarily the result of milder weather. Compared to the second quarter of 2013, residential electric use per customer decreased 3 percent. Heating degree days at Spokane were 16 percent below historical average for the second quarter of 2014 and were 10 percent below the second quarter of 2013. Cooling degree days at Spokane (primarily for June) were 69 percent below average and 77 percent below the second quarter of 2013. There has historically not been a significant amount of cooling degree days during the second quarter.

The decrease in total MWhs sold to industrial customers was primarily due to the expiration and replacement of a contract with one of our largest industrial customers, effective July 1, 2013. Under the new contract, we expect a decrease in revenues from annual power sales to this customer of approximately $21 million and a resulting decrease in resource costs of approximately $19 million. Any change in revenues and expenses associated with the new agreement, as compared with the revenues and expenses included in the last general rate case for this customer, are tracked through the PCA in Idaho at 100 percent, until such time as the contract is included in the Company's base rates, so that we expect no impact on our gross margin or net income from the new agreement.

Wholesale electric revenues decreased $1.3 million due to a decrease in sales volumes (decreased revenues $7.6 million), partially offset by an increase in sales prices (increased revenues $6.3 million). The fluctuation in volumes and prices was primarily the result of 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 $11.5 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 second quarter of 2014, $13.8 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For the second quarter of 2013, $26.3 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.

The 2013 Idaho general rate case settlement includes an after-the-fact earnings test for 2013 and 2014, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earns more than a 9.8 percent return on equity, we will share with customers 50 percent of any earnings above the 9.8 percent. In the second quarter of 2014, we estimated a provision for earnings sharing of $1.2 million for Idaho electric customers, which reflects our cumulative estimate through the first six months ended June 30, 2014.

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

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2014	2013	2014	2013
Residential	$ 30,997	$ 30,340	26,549	27,913
Commercial	15,571	15,057	17,105	17,595
Interruptible	582	515	1,058	1,084
Industrial	848	731	1,140	1,062
Total retail	47,998	46,643	45,852	47,654
Wholesale	48,934	35,436	110,067	94,997
Transportation	1,841	1,753	37,638	34,031
Other	1,643	2,024	74	75
Provision for earnings sharing	(137)	—	—	—
Total	$ 100,279	$ 85,856	193,631	176,757

Retail natural gas revenues increased $1.4 million due to higher retail rates (increased revenues $3.3 million), partially offset by a decrease in volumes (decreased revenues $1.9 million). Higher retail rates were due to PGAs, which passed through higher costs of natural gas, and general rate cases. We sold less retail natural gas in the second quarter of 2014 as compared to the second quarter of 2013 primarily due to milder weather. Compared to the second quarter of 2013, residential natural gas use per customer decreased 6 percent and commercial use per customer decreased 3 percent. Heating degree days at Spokane were 16 percent below historical average for the second quarter of 2014, and 10 percent below the second quarter of 2013. Heating degree days at Medford were 44 percent below historical average for the second quarter of 2014 and 20 percent below the second quarter of 2013.

Wholesale natural gas revenues increased $13.5 million due to an increase in prices (increased revenues $6.8 million) and an increase in volumes (increased revenues $6.7 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 second quarter of 2014, $14.6 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In the second quarter of 2013, $5.6 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.

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

	Electric Customers		Natural Gas Customers	
	2014	2013	2014	2013
Residential	322,919	320,018	291,257	288,109
Commercial	41,015	40,126	34,017	33,986
Interruptible	—	—	36	36
Industrial	1,395	1,387	260	258
Public street and highway lighting	534	527	—	—
Total retail customers	365,863	362,058	325,570	322,389

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

	2014	2013
Electric resource costs:		
Power purchased	$ 37,138	$ 44,718
Power cost amortizations, net	2,793	84
Fuel for generation	12,984	18,438
Other fuel costs	20,713	31,498
Other regulatory amortizations, net	5,304	(3,431)
Other electric resource costs	5,088	7,412
Total electric resource costs	84,020	98,719
Natural gas resource costs:		
Natural gas purchased	77,264	60,856
Natural gas cost amortizations, net	(4,784)	(2,353)
Other regulatory amortizations, net	834	1,173
Total natural gas resource costs	73,314	59,676
Intracompany resource costs	(28,412)	(31,884)
Total resource costs	$ 128,922	$ 126,511

Power purchased decreased $7.6 million due to a decrease in the volume of power purchases (decreased costs $11.6 million), partially offset by an increase in wholesale prices (increased costs $4.0 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.

Amortizations of net deferred power costs increased electric resource costs by $2.8 million for the three months ended June 30, 2014 compared to $0.1 million for the three months ended June 30, 2013. During the three months ended June 30, 2014, we refunded to customers $1.1 million of previously deferred power costs in Idaho through the PCA rebate. We also refunded to Washington customers $2.0 million through an ERM rebate. During the three months ended June 30, 2014, actual power supply costs were below the amount included in base retail rates in Washington and we deferred $3.0 million for probable future benefit to customers. We deferred $2.8 million in Idaho for probable future benefit to customers.

Fuel for generation decreased $5.5 million due to a decrease in natural gas generation (due in part to increased hydroelectric generation), partially offset by an increase in natural gas fuel prices.

Other fuel costs decreased $10.8 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.

Electric other regulatory amortizations increased $8.7 million primarily due to the regulatory recognition of $7.6 million in the second quarter of 2013 for the Washington portion of the BPA revenue for past use of our transmission system as approved by the UTC. See further information above at "Bonneville Power Administration Reimbursement and Reardan Wind Generation Project."

Other electric resource costs decreased $2.3 million primarily due to the second quarter of 2013 write-off of $2.5 million of Reardan project costs that were allocable to our Washington business.

The expense for natural gas purchased increased $16.4 million due to an increase in the price of natural gas (increased costs $9.8 million) and an increase in total therms purchased (increased costs $6.6 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.

Six months ended June 30, 2014 compared to the six months ended June 30, 2013

Net income for Avista Utilities was $74.7 million for the first half of 2014, an increase from $66.8 million for the first half of 2013. Avista Utilities' income from operations was $145.6 million for the first half of 2014, an increase from $138.0 million for the first half of 2013. The increase in net income and income from operations was primarily due to the implementation of general rate increases and colder weather during the first quarter, partially offset by expected increases in other operating expenses, depreciation and amortization, and taxes other than income taxes.

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

	Electric		Natural Gas		Intracompany		Total	
	2014	2013	2014	2013	2014	2013	2014	2013
Operating revenues	$ 506,124	$ 531,935	$ 298,300	$ 271,127	$ (63,295)	$ (73,316)	$ 741,129	$ 729,746
Resource costs	205,900	243,782	206,814	185,675	(63,295)	(73,316)	349,419	356,141
Gross margin	$ 300,224	$ 288,153	$ 91,486	$ 85,452	$ —	$ —	$ 391,710	$ 373,605

Avista Utilities' operating revenues increased $11.4 million and resource costs decreased $6.7 million, which resulted in an increase of $18.1 million in gross margin. The gross margin on electric sales increased $12.1 million and the gross margin on natural gas sales increased $6.0 million. The increase in electric gross margin was primarily due to general rate increases in Washington and Idaho and lower power supply costs (due in part to increased hydroelectric generation), as well as colder weather in the first quarter. For the six months ended June 30, 2014, we recognized a pre-tax benefit of $4.9 million under the ERM in Washington compared to a benefit of $4.1 million for the six months ended June 30, 2013. Electric gross margin for 2013 included the net benefit from the settlement with the BPA. The increase in natural gas gross margin was due to general rate increases. A colder than average and the prior year first quarter was partially offset by milder weather in the second quarter as year-to-date use per customer did not change significantly.

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 six months ended June 30 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2014	2013	2014	2013
Residential	$ 173,744	$ 163,288	1,893	1,856
Commercial	145,726	138,123	1,552	1,502
Industrial	53,427	60,585	907	1,082
Public street and highway lighting	3,783	3,677	13	13
Total retail	376,680	365,673	4,365	4,453
Wholesale	72,887	76,961	2,100	2,512
Sales of fuel	46,179	65,260	—	—
Other	13,482	24,041	—	—
Provision for earnings sharing	(3,104)	—	—	—
Total	$ 506,124	$ 531,935	6,465	6,965

Retail electric revenues increased $11.0 million due to an increase in revenue per MWh (increased revenues $18.6 million), partially offset by a decrease in total MWhs sold (decreased revenues $7.6 million). The increase in revenue per MWh was primarily due to general rate increases and a change in revenue mix, with a greater percentage of retail revenue from residential and commercial customers.

The increase in total MWhs sold to residential customers was primarily the result of colder weather in the first quarter, mostly offset by milder weather in the second quarter. Compared to the six months ended June 30, 2013, residential electric use per customer increased 1 percent. Heating degree days at Spokane were 2 percent below historical average and were 0.4 percent above the six months ended June 30, 2013. Cooling degree days at Spokane (primarily for June) were 69 percent below average and 77 percent below the six months ended June 30, 2013. There has historically not been a significant amount of cooling degree days during the first six months of each year.

The decrease in total MWhs sold to industrial customers was primarily due to the expiration and replacement of a contract with one of our largest industrial customers, effective July 1, 2013. Under the new contract, we expect a decrease in revenues from annual power sales to this customer of approximately $21 million and a resulting decrease in resource costs of approximately $19 million. Any change in revenues and expenses associated with the new agreement, as compared with the revenues and expenses included in the last general rate case for this customer, are tracked through the PCA in Idaho at 100 percent, until such time as the contract is included in the Company's base rates, so that we expect no impact on our gross margin or net income from the new agreement.

Wholesale electric revenues decreased $4.1 million due to a decrease in sales volumes (decreased revenues $14.3 million), partially offset by an increase in sales prices (increased revenues $10.2 million). The fluctuation in volumes and prices was primarily the result of 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 $19.1 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 six months ended June 30, 2014, $30.9 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For the six months ended June 30, 2013, $54.2 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.

Other electric revenues decreased $10.5 million primarily due to the receipt of $11.7 million of revenue from the BPA in the first quarter of 2013 for past use of our electric transmission system. The majority of this revenue was deferred as a regulatory liability and included in electric resource costs during the first quarter of 2013. During the second quarter of 2013, the UTC authorized us to retain a portion of this payment, which was then recognized to earnings, net of the Reardan wind generation project costs. See further information above at "Bonneville Power Administration Reimbursement and Reardan Wind Generation Project."

The 2013 Idaho general rate case settlement includes an after-the-fact earnings test for 2013 and 2014, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earns more than a 9.8 percent return on equity, we will share with customers 50 percent of any earnings above the 9.8 percent. In the six months ended June 30, 2014, we estimated a provision for earnings sharing of $3.1 million for Idaho electric customers with $1.2 million representing our estimate for the six months ended June 30, 2014 and $1.9 million representing an adjustment of our 2013 estimate.

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

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2014	2013	2014	2013
Residential	$ 117,816	$ 110,294	112,710	112,053
Commercial	59,496	54,440	67,763	66,049
Interruptible	1,430	1,260	2,582	2,664
Industrial	2,244	1,865	2,991	2,738
Total retail	180,986	167,859	186,046	183,504
Wholesale	109,419	95,134	236,109	258,388
Transportation	3,995	3,835	84,648	80,317
Other	4,039	4,299	293	282
Provision for earnings sharing	(139)	—	—	—
Total	$ 298,300	$ 271,127	507,096	522,491

Retail natural gas revenues increased $13.1 million due to higher retail rates (increased revenues $10.6 million) and partially due to an increase in volumes (increased revenues $2.5 million). Higher retail rates were due to PGAs, which passed through higher costs of natural gas, and general rate cases. We sold more retail natural gas in the six months ended June 30, 2014 as compared to the six months ended June 30, 2013 primarily due to customer growth and colder weather in the first quarter, partially offset by milder weather in the second quarter. Compared to the six months ended June 30, 2013, residential natural gas use per customer decreased 0.3 percent and commercial use per customer increased 2 percent. Heating degree days at Spokane were 2 percent below historical average for the six months ended June 30, 2014, and 0.4 percent above the six months ended June 30, 2013. Heating degree days at Medford were 22 percent below historical average for the six months ended June 30, 2014 and 16 percent below the six months ended June 30, 2013.

Wholesale natural gas revenues increased $14.3 million due to an increase in prices (increased revenues $24.6 million), partially offset by a decrease in volumes (decreased revenues $10.3 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 six months ended June 30, 2014, $32.4 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In the six months ended June 30, 2013, $19.2 million of these sales were made to our electric generation operations. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.

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

	Electric Customers		Natural Gas Customers	
	2014	2013	2014	2013
Residential	323,415	320,349	291,583	288,609
Commercial	40,852	40,111	34,080	34,030
Interruptible	—	—	36	37
Industrial	1,390	1,385	259	261
Public street and highway lighting	532	525	—	—
Total retail customers	366,189	362,370	325,958	322,937

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

	2014	2013
Electric resource costs:		
Power purchased	$ 98,803	$ 103,681
Power cost amortizations, net	(2,884)	(437)
Fuel for generation	47,951	54,612
Other fuel costs	40,923	62,195
Other regulatory amortizations, net	10,710	11,463
Other electric resource costs	10,397	12,268
Total electric resource costs	205,900	243,782
Natural gas resource costs:		
Natural gas purchased	210,132	180,759
Natural gas cost amortizations, net	(7,148)	767
Other regulatory amortizations, net	3,830	4,149
Total natural gas resource costs	206,814	185,675
Intracompany resource costs	(63,295)	(73,316)
Total resource costs	$ 349,419	$ 356,141

Power purchased decreased $4.9 million due to a decrease in the volume of power purchases (decreased costs $13.9 million), partially offset by an increase in wholesale prices (increased costs $9.0 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.

Amortizations of net deferred power costs decreased electric resource costs by $2.9 million for the six months ended June 30, 2014 compared to $0.4 million for the six months ended June 30, 2013. During the six months ended June 30, 2014, we refunded to customers $2.4 million of previously deferred power costs in Idaho through the PCA rebate. We also refunded to Washington customers $4.2 million through an ERM rebate. During the six months ended June 30, 2014, actual power supply costs were below the amount included in base retail rates in Washington and we deferred $3.2 million for probable future benefit to customers. We deferred $0.5 million in Idaho for probable future benefit to customers.

Fuel for generation decreased $6.7 million due to a decrease in natural gas generation (due in part to increased hydroelectric generation), partially offset by an increase in natural gas fuel prices.

Other fuel costs decreased $21.3 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 $1.9 million primarily due to the second quarter of 2013 write-off of $2.5 million of Reardan project costs that were allocable to our Washington business.

The expense for natural gas purchased increased $29.4 million due to an increase in the price of natural gas (increased costs $39.2 million), partially offset by a decrease in total therms purchased (decreased costs $9.8 million). Total therms purchased decreased due to a decrease 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 an increase 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.

Ecova - Discontinued Operations

As discussed in "Item 2. Management's Discussion and Analysis: Executive Level Summary," Ecova was disposed of as of June 30, 2014. As a result, in accordance with GAAP, all of Ecova's operating results have been removed from each line item on the Condensed Consolidated Statements of Income and reclassified into discontinued operations for all periods presented. In addition, since Ecova was a subsidiary of Avista Capital, the net gain recognized on the sale of Ecova was attributable to our other businesses. However, in accordance with GAAP, this gain is included in discontinued operations; therefore, we have included the analysis of the gain in the Ecova discontinued operations section rather than in the other businesses section. Also, for our business segment presentation at "Note 13 of the Notes to Condensed Consolidated Financial Statements," we have included in the net gain in Ecova's net income so it will reconcile with the amounts reported for discontinued operations.

Three months ended June 30, 2014 compared to the three months ended June 30, 2013

Ecova's net income attributable to Avista Corp. shareholders was $69.7 million for the three months ended June 30, 2014 compared to $1.5 million for the three months ended June 30, 2013. The increase was primarily attributable to the net gain recognized on the sale of Ecova of $68.1 million. Excluding the net gain, net income from Ecova's regular operations increased $0.1 million and was the result of a decrease in depreciation and amortization, partially offset by a decrease in operating revenues.

Six months ended June 30, 2014 compared to the six months ended June 30, 2013

Ecova's net income attributable to Avista Corp. shareholders was $70.8 million for the six months ended June 30, 2014 compared to $2.7 million for the six months ended June 30, 2013. The increase was primarily attributable to the net gain recognized on the sale of Ecova of $68.1 million. Excluding the net gain, net income from Ecova's regular operations were flat compared to 2013 and were the result of a decrease in depreciation and amortization expense, an increase in operating revenues, offset by an increase in operating expenses.

Other Businesses

Our other businesses include sheet metal fabrication, venture fund investments and real estate investments, as well as certain other operations of Avista Capital. 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 shows our assets related to our other businesses as of June 30, 2014 and December 31, 2013 (dollars in thousands):

	June 30, 2014	December 31, 2013
Spokane Energy (1)	$ 36,743	$ 42,829
Avista Energy (2)	—	12,399
METALfx	11,371	11,105
Steam Plant and Courtyard Office Center	7,261	7,055
Other (3)	27,128	7,894
Total	$ 82,503	$ 81,282

(1) The decrease in the value of Spokane Energy assets represents the continued amortization of the long-term fixed rate electric capacity contract. See “Note 9 of the Notes to Condensed Consolidated Financial Statements” for further information regarding the long-term fixed rate electric capacity contract and the related nonrecourse long-term debt.

(2) As of June 30, 2014, Avista Energy had $2.7 million of income tax receivables; however, on a consolidated basis, these receivables are netted with other income tax payables and included as a net liability on the Condensed Consolidated Balance Sheets.

(3) The balance at June 30, 2014 includes $13.6 million in escrow amounts related to the sale of Ecova and net cash of $5.5 million held at Avista Capital.

Three months ended June 30, 2014 compared to the three months ended June 30, 2013

The net income from these operations was $4.5 million for the three months ended June 30, 2014 compared to a net loss of $0.4 million for the three months ended June 30, 2013. The net income for the second quarter of 2014 was primarily the result of the settlement of the California power markets litigation, where Avista Energy received settlement proceeds and recognized an increase in pre-tax earnings of approximately $15.0 million. This was partially offset by a pre-tax contribution of $6.4 million of the proceeds to the Avista Foundation. See "Note 12 of the Notes to the Condensed Consolidated Financial Statements" for further information regarding this litigation settlement.

METALfx had net income of $0.2 million for the second quarter of 2014, compared to net income of $0.3 million for the second quarter of 2013.

Lastly, we incurred approximately $0.6 million (net of tax) of corporate costs, including costs associated with exploring strategic opportunities.

Six months ended June 30, 2014 compared to the six months ended June 30, 2013

The net income from these operations was $3.9 million for the six months ended June 30, 2014 compared to a net loss of $1.5

million for the six months ended June 30, 2013. The net income for the first half of 2014 was primarily the result of the settlement of the California power markets litigation, where Avista Energy received settlement proceeds and recognized an increase in pre-tax earnings of approximately $15.0 million. This was partially offset by a pre-tax contribution of $6.4 million of the proceeds to the Avista Foundation. See "Note 12 of the Notes to the Condensed Consolidated Financial Statements" for further information regarding this litigation settlement.

METALfx had net income of $0.3 million for the first half of 2014, compared to net income of $0.5 million for the first half of 2013.

Lastly, we incurred approximately $1.1 million (net of tax) of corporate costs, including costs associated with exploring strategic opportunities.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with accounting principles generally accepted in the United States of America 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 2013 Form 10-K and have not changed materially from that discussion.

Liquidity and Capital Resources

Overall Liquidity

During the second quarter of 2014, we received cash proceeds of $15.0 million from the California power markets litigation settlement and $205.4 million from the Ecova disposition. We expect to receive additional proceeds of $13.6 million from the escrow accounts related to the Ecova sale ($1.1 million in 2014 and $12.5 million in 2015) and we also expect to make tax payments of $85.8 million in 2014 associated with the sale. This will result in total net proceeds (after taxes and escrow amounts) of $133.2 million. We used the above funds to contribute $6.4 million to the Avista Foundation, pay off the outstanding balance owed on our committed line of credit on July 1, 2014 of $151.5 million and we initiated a common stock share repurchase program.

Our consolidated operating cash flows are primarily derived from the operations of Avista Utilities. The primary source of operating cash flows for our utility operations is revenues from sales of electricity and natural gas. Significant uses of cash flows from our utility operations 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 at "Capital Resources."

We periodically file for rate adjustments for recovery of operating costs and capital investments to seek the opportunity to earn reasonable returns as allowed by regulators. See further details in the section "Avista Utilities - Regulatory Matters."

For our utility operations, 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.

We monitor the potential liquidity impacts of changes to energy commodity prices and other increased operating costs for our utility operations. We believe that we have adequate liquidity to meet such potential needs through our $400.0 million committed line of credit.

As of June 30, 2014, we had $226.6 million of available liquidity under our 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.

Our utility 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.

Review of Cash Flow Statement

Overall During the six months ended June 30, 2014, positive cash flows from operating activities of $224.0 million were used to fund the majority of our cash requirements. These cash requirements included utility capital expenditures of $136.5 million, dividends of $38.3 million, the repayment of short-term borrowings of $19.5 million and contributions to our pension plan of $21.5 million.

In addition, during the second quarter of 2014 we sold Ecova and received net proceeds of $205.4 million (prior to estimated tax payments of $85.8 million to be made in the second half of 2014 and estimated escrow receipts of $1.1 million in 2014 and $12.5 million in 2015). In July 2014, we utilized a portion of these proceeds to pay off the outstanding balance owed on our committed line of credit and we initiated a common stock share repurchase program and expect to fund our stock repurchases for up to 4 million shares during the second half of 2014. We have the option to terminate the stock repurchase program prior to December 31, 2014.

Operating Activities Net cash provided by operating activities was $224.0 million for the six months ended June 30, 2014 compared to $155.8 million for the six months ended June 30, 2013. Net cash provided by changes in certain current assets and liabilities was $144.2 million for the first half of 2014, compared to net cash provided of $16.3 million for the first half of 2013. The net cash provided by certain current assets and liabilities during the first half of 2014 primarily reflects positive cash flows related to accounts receivable, income taxes payable, other current assets (primarily related to a fluctuation in income taxes receivable) and other current liabilities (primarily related to smaller fluctuations in various miscellaneous accrued liabilities). These positive cash flows were partially offset by net cash outflows related to accounts payable and materials and supplies.

The net cash provided by certain current assets and liabilities during the first half of 2013 primarily reflects positive cash flows related to accounts receivable and income taxes payable. These positive cash flows were partially offset by net cash outflows related to accounts payable and other current assets.

The gross gain on the sale of Ecova of $161.1 million for the first half of 2014 was excluded from operating cash flows and included in investing activities. Net deferrals of power and natural gas costs decreased operating cash flows by $10.0 million for the six months ended June 30, 2014 compared to a decrease in operating cash flows of $0.4 million for the six months ended June 30, 2013. The provision for deferred income taxes was $24.2 million for the six months ended June 30, 2014 compared to a benefit of $1.4 million for the six months ended June 30, 2013. Contributions to our defined benefit pension plan were $21.5 million for the first half of 2014 and $29.3 million for the first half of 2013. Cash paid for income taxes was $1.5 million for the first half of 2014, compared to $29.0 million for the first half of 2013.

Investing Activities Net cash provided by investing activities was $67.2 million for the six months ended June 30, 2014, compared to net cash used of $154.9 million for the six months ended June 30, 2013. During the first half of 2014, we received cash proceeds (net of cash sold and escrow amounts) of $229.9 million related to the sale of Ecova. The fluctuation in the balance of Ecova cash sold compared to our expectations was addressed through the working capital adjustment included in the Ecova sales agreement. A portion of the proceeds from the Ecova sale was used to pay off the balance of Ecova's long-term borrowings and make payments to option holders and noncontrolling interests (included in financing activities). We will also use a portion of these proceeds to pay our tax liability associated with the gain on sale once it becomes due. Utility property capital expenditures decreased by $8.8 million for the first half of 2014 as compared to the first half of 2013. A significant portion of Ecova's funds were held as securities available for sale and they had purchases of $12.3 million and sales and maturities of $14.6 million for 2014 compared with purchases of $31.9 million and sales and maturities of $15.1 million for 2013. The fluctuation in the balance of funds held for customers resulted in a decrease to cash of $18.9 million for the first half of 2014 compared to an increase to cash of $10.7 million for the first half of 2013. We made $4.7 million in cash payments to acquire AERC during the first half of 2014 and we have recorded these amounts to other deferred charges as of June 30, 2014. On July 1, 2014, at the completion of the acquisition of AERC, these cash payments are part of the purchase consideration paid for AERC.

Financing Activities Net cash used in financing activities was $165.8 million for the six months ended June 30, 2014 compared to net cash provided of $9.1 million for the six months ended June 30, 2013. During the first half of 2014, short-term borrowings on Avista Corp.'s committed line of credit decreased $19.5 million. Net borrowings on Ecova's committed line of credit decreased $46.0 million during the period with $6.0 million in payments throughout the year and $40.0 million related to the close of the sale. In connection with the closing of the Ecova sale, we made cash payments of $54.2 million to noncontrolling interests and $20.9 million to stock option holders and redeemable noncontrolling interests of Ecova. Cash dividends paid to Avista Corp. shareholders increased to $38.3 million (or $0.635 per share) for the first half of 2014 from $36.7 million (or $0.61 per share) for the first half of 2013. We issued $2.0 million of common stock during the six months ended June 30, 2014. The fluctuation in the balance of customer fund obligations at Ecova increased cash by $16.2 million.

During the six months ended June 30, 2013, short-term borrowings on Avista Corp.'s committed line of credit increased $43.5 million. Net borrowings on Ecova's line of credit decreased $2.0 million, with $3.0 million of borrowings and $5.0 million of repayments. We issued $3.0 million of common stock during the six months ended June 30, 2013. In June 2013, we cash settled two interest rate swap contracts (notional amount of $85.0 million) and received a total of $2.9 million. Customer fund obligations at Ecova increased $6.2 million.

Collateral Requirements

Our contracts for the purchase and sale of energy commodities can require collateral in the form of cash or letters of credit. As of June 30, 2014, we had deposited cash in the amount of $9.4 million and letters of credit of $14.8 million as collateral for certain 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 June 30, 2014, we would potentially be required to post additional collateral of up to $4.6 million. This amount is different from the amount disclosed in “Note 6 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 6, this analysis takes into account contractual threshold limits that are not considered in Note 6. Without contractual threshold limits, we would potentially be required to post additional collateral of $6.8 million.

Under the terms of interest rate swap agreements that we enter into periodically, we may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the instrument. This has not historically been significant to our liquidity position. As of June 30, 2014, we had interest rate swap agreements outstanding with a notional amount totaling $380 million and we had posted $7.0 million of cash collateral related to these outstanding agreements. If our credit ratings were lowered to below “investment grade” based on our interest rate swap agreements outstanding at June 30, 2014, we would be required to post additional collateral of $2.3 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 June 30, 2014 and December 31, 2013 (dollars in thousands):

	June 30, 2014		December 31, 2013	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 4,348	0.2%	$ 358	—%
Current portion of nonrecourse long-term debt (Spokane Energy)	9,812	0.3%	16,407	0.6%
Short-term borrowings	151,500	5.2%	171,000	6.0%
Long-term borrowings under committed line of credit	—	—%	46,000	1.6%
Long-term debt to affiliated trusts	51,547	1.8%	51,547	1.8%
Nonrecourse long-term debt (Spokane Energy)	—	—%	1,431	0.1%
Long-term debt	1,268,530	43.8%	1,272,425	44.5%
Total debt	1,485,737	51.3%	1,559,168	54.6%
Total Avista Corporation shareholders’ equity	1,410,016	48.7%	1,298,266	45.4%
Total	$ 2,895,753	100.0%	$ 2,857,434	100.0%

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. Our shareholders’ equity increased $111.8 million during the first half of 2014 primarily due to net income, which included the net gain on the sale of Ecova, partially offset by dividends.

We generally fund capital expenditures with a combination of internally generated cash and external financing. The level of cash generated internally and the amount that is available for capital expenditures fluctuates depending on a variety of factors.

Cash provided by our utility operating activities, as well as issuances of long-term debt and common stock, are expected to be the primary source of funds for operating needs, dividends and capital expenditures for 2014. Borrowings under our $400.0 million committed line of credit will supplement these funds to the extent necessary.

During the second quarter of 2014, we received cash proceeds of $205.4 million from the Ecova sale, and we expect to receive additional proceeds of $13.6 million from the escrow accounts related to the sale ($1.1 million in 2014 and $12.5 million in 2015). We also received $15 million from the California power markets litigation settlement. We used the above funds to pay off the outstanding balance owed on our committed line of credit on July 1, 2014, of $151.5 million, we contributed $6.4 million to the Avista Foundation, and we initiated a common stock share repurchase program for up to 4 million shares during the second half of 2014. We expect to borrow funds on our committed line of credit later during the third quarter of 2014, because we expect to make tax payments of $85.8 million associated with the sale of Ecova, and we will need additional funds to complete our stock repurchase program.

We are party to two sales agency agreements for the sale from time to time of shares of our common stock; however, we do not plan to issue any shares under these agreements during 2014 due to the AERC transaction.

In the six months ended June 30, 2014, we issued $2.0 million (net of issuance costs) of common stock under the dividend reinvestment and direct stock purchase plan, and employee plans. On July 1, 2014, we issued 4.5 million shares of common stock at a total fair value of approximately $150 million related to closing the AERC transaction. We do not expect to issue any additional shares for 2014, other than those under the dividend reinvestment and direct stock purchase plan, and employee plans.

As discussed above, on July 7, 2014, we commenced a stock repurchase program to repurchase up to 4 million shares of our outstanding common stock. The program will not continue past December 31, 2014 and we have the option to terminate the program before that date.

We expect to issue approximately $165.0 million of long-term debt during 2014, including about $90.0 million of debt issuances combined between AERC and AEL&P associated with rebalancing the consolidated capital structure at AERC. In July 2014, AEL&P entered into a bond purchase agreement with two institutional investors in the private placement market for the purpose of issuing $75.0 million of 4.54 percent first mortgage bonds due in 2044. The new first mortgage bonds will be issued under and in accordance with the AEL&P mortgage and Deed of Trust, dated as of July 1, 2014, from AEL&P to U.S. Bank, N.A., trustee. The issuance of the bonds will occur at closing in September 2014. In addition to the first mortgage bonds, we expect to issue $15.0 million in term loans at AERC during the third quarter of 2014. We acquired AERC primarily by issuing Avista Corp. common stock; therefore, the proceeds from the new AERC and AEL&P debt will be used to repay approximately $38.0 million of existing AEL&P debt and the remainder of the proceeds will be paid as a cash dividend up to Avista Corp. The issuance of long-term debt of $75.0 million at Avista Corp. will be used primarily to fund Avista Utilities' capital expenditures and other contractual commitments.

Included in our 2014 liquidity estimates is approximately $50.0 million of lower tax payments (exclusive of any amount of taxes payable on the Ecova sales transaction) due to the planned adoption of federal tax tangible property regulations. This will be accomplished through an accounting method change filing with the Internal Revenue Service that will retroactively modify which tangible property transactions we expense versus capitalize and depreciate for federal tax purposes. We have engaged a third party specialist to evaluate our proposed accounting method change filing and the estimated tax savings.

We have a committed line of credit with various financial institutions in the total amount of $400 million. In April 2014, we amended this committed line of credit agreement to extend the expiration date to April 2019. The amendment also provides us with the option to request an extension for an additional one or two years beyond April 2019, provided there is no event of default prior to the requested extension and the requested extension does not cause the remaining term until the expiration date to exceed five years. The amendment did not change the amount of the committed line of credit. Borrowings under this line of credit agreement are classified as short-term on the Condensed Consolidated Balance Sheets. As discussed above, on July 1, 2014, we paid off the cash borrowing balance of this committed line of credit agreement.

AEL&P has a committed line of credit in the amount of $14.5 million with an expiration date of June 2015. As of June 30, 2014, there were no borrowings outstanding under this committed line of credit.

The facility at Avista Corp. contains customary covenants and default provisions, including a covenant which does not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 65 percent at any time. As of June 30, 2014, we were in compliance with this covenant with a ratio of 51.3 percent.

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 six months ended June 30 (dollars in thousands):

	2014	2013
Borrowings outstanding at end of period	$ 151,500	$ 95,500
Letters of credit outstanding at end of period	$ 21,864	$ 24,078
Maximum borrowings outstanding during the period	$ 151,500	$ 95,500
Average borrowings outstanding during the period	$ 68,247	$ 18,327
Average interest rate on borrowings during the period	1.13%	1.08%
Average interest rate on borrowings at end of period	3.02%	1.11%

Prior to the disposition of Ecova on June 30, 2014, as part of our cash management practices and operations, Ecova and Avista Corp. entered into an arrangement in January 2012 under which (1) Avista Corp. issued to Ecova a master unsecured promissory note and (2) Ecova would from time to time make short-term loans to Avista Corp. as a temporary investment of its funds received from its clients. The master promissory note limited the total outstanding indebtedness to no more than $50.0 million in principal. Additionally, such loans were required to be repaid on the last business day of each quarter (March, June, September and December) and sooner upon demand by Ecova. Amounts were loaned at a rate consistent with Avista Corp.'s credit facility. The average balance outstanding was $38.7 million and the maximum balance was $50.0 million during the six months ended June 30, 2014. The average balance outstanding was $32.0 million and the maximum balance was $50.0 million during the six months ended June 30, 2013. There was no balance outstanding under the credit agreement as June 30, 2014 and the credit agreement has been terminated.

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 June 30, 2014, 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 $355 million for 2014, $355 million in 2015 and $350 million in 2016. In addition, we expect to spend approximately $6 million for 2014 and $15 million for each of 2015 and 2016 related to capital expenditures at AEL&P. The $20 million increase in estimated Avista Utilities' capital expenditures for 2014 relates to the replacement of our customer information system and work management systems. Most of these capital expenditures are for upgrading and maintenance of our existing facilities, and a portion is for growth of our customer base. 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.

Future generation resource decisions may be further impacted by legislation restricting greenhouse gas (GHG) emissions and renewable energy requirements as discussed at “Environmental Issues and Other Contingencies.”

Included in our estimates of capital expenditures is the replacement of our customer information and work management systems, which is expected to be completed during the first half of 2015. Our customer information and work management systems are two of our most critical technology systems and are interconnected to many other systems in our company. We expect to spend approximately $100.0 million (including internal labor) over the term of the project. As of June 30, 2014 we have spent $67.1 million on the project (including internal labor).

Off-Balance Sheet Arrangements

As of June 30, 2014, we had $21.9 million in letters of credit outstanding under our $400.0 million committed line of credit, compared to $27.4 million as of December 31, 2013.

Pension Plan

In the six months ended June 30, 2014 we contributed $21.5 million to the pension plan. We expect to contribute a total of $80.0 million to the pension plan in the period 2014 through 2018, with the following contributions.

	2014	2015	2016	2017	2018	Total
Pension Plan Funding	$ 32,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 80,000

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 of the above variables.

In October 2013, we revised our defined benefit pension plan such that as of January 1, 2014 the plan is closed to all non-union employees hired or rehired by us on or after January 1, 2014. All actively employed non-union employees that were hired prior to January 1, 2014 and who are currently covered under the defined benefit pension plan will continue accruing benefits as originally specified in the plan. A defined contribution 401(k) plan will replace the defined benefit pension plan for all non-union employees hired or rehired on or after January 1, 2014. Under the defined contribution plan we will provide a non-elective contribution as a percentage of each employee's pay based on his or her age. This defined contribution is in addition to the existing 401(k) contribution in which we match a portion of the pay deferred by each participant. In addition to the above changes, we also revised our lump sum calculation for non-union retirees under the defined benefit pension plan to provide non-union participants who retire on or after January 1, 2014 with a lump sum amount equivalent to the present value of the benefits based upon applicable discount rates.

Also in October 2013, we revised the health care benefit plan such that beginning on January 1, 2020, the method for calculating health insurance premiums for non-union retirees under age 65 and active Company employees will be revised. The revisions will result in separate health insurance premium calculations for each group. In addition, for non-union employees hired or rehired on or after January 1, 2014, upon retirement we will no longer provide a contribution towards his or her medical premiums. We will provide access to our retiree medical plan, but the non-union employees hired or rehired on or after January 1, 2014 will pay the full cost of premiums upon retirement.

In April 2014, the local union in Oregon for the International Brotherhood of Electrical Workers accepted the defined benefit pension and health care benefit plan changes above in the latest collective bargaining agreement, and the plan changes are effective for Oregon union workers hired or rehired on or after April 1, 2014.

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 6 of the Notes to Condensed Consolidated Financial Statements.”

The following table summarizes our credit ratings as of August 8, 2014:

	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.

Our net income available for dividends is primarily derived from our regulated utility operations.

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 (see Item 7. Management's Discussion and Analysis - "Capital Resources" for compliance with these covenants), and
- the hydroelectric licensing requirements of section 10(d) of the FPA (see "Note 1 of Notes to Condensed Consolidated Financial Statements").

On May 8, 2014, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.3175 per share on the Company's common stock, which was equal to the previous quarter's dividend.

Contractual Obligations

The following contractual obligations have materially changed during the six months ended June 30, 2014. The items removed relate to Ecova and are no longer applicable due to its disposition on June 30, 2014. Effective July 1, 2014, we have added the below contractual obligations due to our acquisition of AERC. See the 2013 Form 10-K for all other contractual obligations.

	2014	2015	2016	2017	2018	Thereafter
Items removed effective June 30, 2014 (Ecova)						
Redeemable noncontrolling interests (1) (4)	$ 16	$ —	$ —	$ —	$ —	$ —
Long-term borrowings under committed line of credit (4)	—	—	—	46	—	—
Interest payments on long-term borrowings under committed line of credit (2) (4)	1	1	1	1	—	—
Operating lease obligations (3) (4)	4	4	3	2	2	4
Client fund obligations (4)	99	—	—	—	—	—
Total contractual obligations removed	120	5	4	49	2	4
Items added effective July 1, 2014 (AERC)						
Long-term debt maturities (5)	1	2	2	2	2	30
Interest payment on long-term debt (5)	1	2	2	2	1	9
Capital lease obligations (3)	3	6	6	6	6	89
Capital funding for hydro project (6)	1	2	2	2	2	30
Other obligations (7)	1	3	3	3	3	39
Total contractual obligations added	$ 7	$ 15	$ 15	$ 15	$ 14	$ 197

(1) Certain shares acquired under Ecova's employee stock incentive plan were redeemable at the option of the shareholder.
(2) Represented our estimate of interest payments on long-term debt, which was calculated based on the assumption that all debt would be outstanding until maturity. Interest on variable rate debt was calculated using the rate in effect at December 31, 2013.
(3) Includes the interest component of the lease obligation.
(4) These were the balances that were disclosed as of December 31, 2013.
(5) Represents the principal and interest payments of the long-term debt currently outstanding at AERC. However, as discussed in "Item 2. Management's Discussion and Analysis: Executive Level Summary," our current expectations are to refinance this existing debt with new debt during the second half of 2014.

(6) Represents the contractually required capital project funding associated with the Snettisham hydroelectric project. These costs are generally recovered through base retail rates.

(7) Represents the operating and maintenance agreement for the Snettisham hydroelectric project. These costs are generally recovered through base retail rates.

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 areas in our service area: Spokane, Washington, Coeur d'Alene, Idaho, and Medford, Oregon. Several key indicators are employment change, unemployment rates and foreclosure rates. On a year-over-year basis, June 2014 showed positive job growth, and lower unemployment rates in two of the three metropolitan areas. Foreclosure rates are in line with or below the U.S. rate in all three areas. However, except for Coeur d'Alene, the unemployment rates are still above the national average. Two key leading indicators, initial unemployment claims and residential building permits, continue to signal modest growth over the next 12 months. Therefore, for the rest of 2014, we continue to expect economic growth in our service area to be somewhat slower than the U.S. as a whole.

Seasonally adjusted nonfarm employment in our eastern Washington, northern Idaho, and southwestern Oregon metropolitan service areas exhibited moderate growth between June 2013 and June 2014. In Spokane, Washington employment increased 0.5 percent with gains in mining, logging, and construction; financial activities; education and health services; other services; and government. Employment increased 3 percent in Coeur d'Alene, Idaho, reflecting gains in construction; manufacturing; trade, transportation and utilities; professional and business services; education and health services; leisure and hospitality; other services; and government. In Medford, Oregon, employment declined 0.6 percent, with gains in manufacturing; leisure and hospitality and government offset by declines in construction; trade, transportation and utilities; information; financial activities; professional and business services; and education and health services. U.S. nonfarm sector jobs grew 1.8 percent in the same twelve-month period.

Seasonally adjusted unemployment rates went down in June 2014 from the year earlier in Spokane, Coeur d'Alene, and Medford. In Spokane the rate was 7.9 percent in June 2013 and declined to 6.4 percent in June 2014; in Coeur d'Alene the rate went from 7.3 percent to 5.3 percent; and in Medford the rate declined from 9.5 percent to 8.5 percent. The U.S. rate declined from 7.5 percent to 6.1 percent in the same period.

The housing market in our service area continues to experience foreclosure rates in line with or lower than the national average. The June 2014 national rate was 0.08 percent, compared to 0.08 percent in Spokane County, Washington; 0.05 percent in Kootenai County (Coeur d'Alene), Idaho; and 0.06 percent in Jackson County (Medford), Oregon.

Environmental Issues and Contingencies

Our environmental issues and contingencies disclosures have not materially changed except for the following during the six months ended June 30, 2014. See the 2013 Form 10-K.

Climate Change - Federal Regulatory Actions

The U.S. Supreme Court ruled in 2007 that the EPA had authority under the Clean Air Act (CAA) to regulate greenhouse gas emissions from new motor vehicles; subsequently, the EPA issued regulations on tailpipe emissions of greenhouse gases (GHG). When these regulations became effective, GHG became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. The EPA re-proposed a rule in late 2013 setting performance standards for GHG emissions from *new and modified* fossil fuel-fired electric generating units and announced plans to issue GHG emissions guidelines for *existing* sources. The rule for *new* sources has not been finalized, and the proposed rule for *existing* sources was released on June 2, 2014. The existing source proposal aims to reduce emissions from covered existing generation sources by 30 percent nationally by 2030. The proposal establishes individual state emission reduction goals based upon assumptions upon the potential for (1) heat rate improvements at coal-fired units, (2) increased utilization of natural gas-fired combined cycle plants up to a 70 percent capacity factor, (3) utilize more low or zero carbon emitting generation resources, and (4) increase demand side efficiency by 1.5 percent per year. States can rely on these four elements, or “building blocks,” as policy mechanisms to meet their respective goals, or they could adopt market mechanisms as an alternative, subject to the EPA's approval. The EPA is accepting comments on the existing source proposal until October 16, 2014 and is expected to finalize the rule by June 2015. The states are scheduled to submit compliance plans to the EPA by June 2016, with a potential for an extension until June 2017, or June 2018 if the state will be part of a regional approach.

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 creates 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 calls 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." While we cannot predict the outcome of actions arising out of the Governor's executive order, 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 final report will be submitted to the Legislature by November 15, 2014. The scope of the study includes an assessment of "potential methods for the [tax] treatment of imported and exported energy sources," which could entail the taxation of natural gas used to generate electricity and/or of the carbon content attributed to electricity produced in the state. A 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 the development of the study and any attendant recommendations made therein, but we cannot predict any actual material impact at this time.

Kettle Falls Generation Station - Diesel Spill Investigation and Remediation

On December 24, 2013, our 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. We made all proper agency notifications and worked closely with the Washington State Department of Ecology during the spill response and investigation phase. We installed ground water monitoring wells, and there is no indication that ground or surface water is threatened by the spill. We have initiated a voluntary cleanup action with the installation of a recovery system. See "Note 12 of the Notes to Condensed Consolidated Financial Statements" for further discussion of this issue.

Other

For other environmental issues and other contingencies see "Note 12 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 six months ended June 30, 2014. Please refer to the 2013 Form 10-K. The following table presents energy commodity derivative fair values as a net asset or (liability) as of June 30, 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)
2014	$ 1,368	$ 11,118	$ —	$ 16,902	$ (275)	$ (11,644)	$ (902)	$ (12,173)
2015	(1,109)	1,809	(261)	1,716	(14)	(2,735)	(1,012)	(689)
2016	(2,513)	2,380	(463)	(1,221)	(56)	309	(772)	(876)
2017	(2,123)	—	142	—	(118)	—	—	—
2018	(1,362)	—	—	—	(245)	—	—	—
Thereafter	(822)	—	—	—	(171)	—	—	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2013 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)
2013	$ (215)	$ 7,243	$ (6,131)	$ (2,663)	$ (221)	$ (6,226)	$ (1,214)	$ (1,404)
2014	(2,818)	(1,798)	(2,450)	(9,586)	(34)	3,121	—	4,298
2015	(3,289)	—	(1,171)	(7,400)	(83)	3,529	—	2,230
2016	(2,955)	—	(86)	—	(187)	—	—	—
2017	(2,661)	—	—	—	(313)	—	—	—
Thereafter	(1,456)	—	—	—	(148)	—	—	—

(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 six months ended June 30, 2014. See the 2013 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 2013 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 2013 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 June 30, 2014 and December 31, 2013 (dollars in thousands):

	June 30, 2014	December 31, 2013
Number of agreements	19	11
Notional amount	$ 380,000	$ 245,000
Mandatory cash settlement dates	2014 to 2018	2014 to 2018
Short-term derivative assets (1)	$ 8,211	$ 13,968
Long-term derivative assets (1)	3,540	19,575
Long-term derivative liability (1) (2)	(13,651)	—

(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 balance as of June 30, 2014 reflects the offsetting of $7.0 million 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 six months ended June 30, 2014. See the 2013 Form 10-K.

The following table summarizes the foreign currency hedges that we have entered into as of June 30, 2014 and December 31, 2013 (dollars in thousands):

	June 30, 2014	December 31, 2013
Number of contracts	26	23
Notional amount (in United States dollars)	$ 9,719	$ 8,631
Notional amount (in Canadian dollars)	10,519	9,191
Other current derivative asset	135	1

Further information for derivatives and fair values is disclosed at “Note 6 of the Notes to Condensed Consolidated Financial Statements” and “Note 10 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 June 30, 2014.

There have been no changes in the Company's internal control over financial reporting that occurred during the second quarter of 2014 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 12 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 2013 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 2013 Form 10-K, except that all risk factors specific to Ecova are no longer relevant due to its disposition on June 30, 2014. The risk factors associated with AERC (acquired on July 1, 2014) are similar to the risk factors already disclosed for Avista Utilities in the 2013 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 4. Mine Safety Disclosures

Not applicable.

Item 6. Exhibits

3.2	Bylaws of Avista Corporation, as amended February 7, 2014*
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 June 30, 2014, 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: August 8, 2014

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

BYLAWS

OF

AVISTA CORPORATION

As Amended February 7, 2014

BYLAWS
OF
AVISTA CORPORATION
* * * * *

ARTICLE I.
Offices

The principal office of the Corporation shall be in the City of Spokane, Washington. The Corporation may have such other offices, either within or without the State of Washington, as the Board of Directors may designate from time to time.

ARTICLE II.
Shareholders

Section 1. Annual Meeting. The Annual Meeting of Shareholders shall be held on such date in the month of May in each year as determined by the Board of Directors for the purpose of electing directors and for the transaction of such other business as may come before the meeting. If the day fixed for the Annual Meeting shall be a legal holiday, such meeting shall be held on the next succeeding business day.

Section 2. Special Meetings.

(a) Special meetings of the shareholders may be called by the President, the Chairman of the Board, a majority of the Board of Directors, or the Governance Committee of the Board, and shall be called by the President at the request of the holders of not less than two-thirds (2/3) of the voting power of all shares of the voting stock voting together as a single class. Only those matters that are specified in the call of or request for a special meeting may be considered or voted at such meeting.

(b) (i) Shareholder demands for a special meeting of shareholders shall be delivered to the principal executive offices of the Corporation, to the attention of the Corporate Secretary, and shall set forth the same information, representations and agreements as required by subsections (b)(iii) and (iv) of Section 11 of Article II as to any nominations proposed to be made at, and by subsection (c)(iii) as to any other business to be brought before, such special meeting.

(ii) A shareholder's demand shall further be updated and supplemented when and as provided in subsections (b)(ii)(B) and (c)(ii)(B) of Section 11 of this Article II.

(c) A special meeting shall be held at the date and time fixed by the Board of Directors; provided, however, that the date of any special meeting called upon demand of shareholders shall be not more than 90 days after the date such demand is received by the Corporate Secretary (or the date of receipt of the last such demand that causes the aggregate number of shares held by shareholders making such demands to meet or exceed 2/3 of the voting power of the voting stock).

(d) In determining whether a special meeting of shareholders has been demanded by holders of at least 2/3 of the voting power of the voting stock, multiple demands delivered to the Corporate Secretary will be considered together only if and to the extent that (i) such demands identify substantially the same purpose or purposes of the special meeting and substantially the same matters proposed to be acted on at the special meeting (in each case as determined by the Board of Directors), (ii) such demands have been dated and delivered to the Corporate Secretary within 60 days of the date of delivery to the Corporate Secretary of the first such demand and (iii) the shareholders making such demands were holders of record of shares representing, in the aggregate, the requisite voting power as of the date of delivery to the Corporate Secretary of the first such demand and remain such holders of record as of the respective dates of delivery of the respective demands, as of the record date of the meeting and as of the date of the meeting.

(e) A shareholder may revoke its demand for a special meeting at any time by delivering a written revocation to the Corporate Secretary. If, following such revocation, the remaining shareholders demanding a special meeting hold in the aggregate less than two-thirds (2/3) of the voting power of the voting stock, the Board of Directors, in its discretion, may cancel the special meeting.

(f) At any special meeting of shareholders, the only business that may properly be brought before the meeting shall be that business set forth in the notice of the meeting issued to shareholders by the Corporation. For any special meeting called upon demand by shareholders, the business to be set forth in the Corporation's notice of the meeting shall be limited to the business set forth in the shareholder demands delivered to the Corporate Secretary, except that the Board of Directors shall have the authority, in its discretion, to include additional items of business in such notice and cause the same to be transacted.

Section 3. Place of Meeting. Meetings of the shareholders, whether they be annual or special, shall be held at the principal office of the Corporation, unless a place, either within or without the state, is otherwise designated by the Board of Directors in the notice provided to shareholders of such meetings.

Section 4. Notice of Meeting. Written or printed notice of every meeting of shareholders shall be mailed by the Corporate Secretary or any Assistant Corporate Secretary, not less than ten (10) nor more than fifty (50) days before the date of the meeting, to each holder of record of stock entitled to vote at the meeting. The notice shall be mailed to each shareholder at his last known post office address, provided, however, that if a shareholder is present at a meeting, or waives notice thereof in writing before or after the meeting, the notice of the meeting to such shareholders shall be unnecessary.

Section 5. Voting of Shares. At every meeting of shareholders each holder of stock entitled to vote thereat shall be entitled to one vote for each share of such stock held in his name on the books of the Corporation, subject to the provisions of applicable law, and may vote and otherwise act in person or by proxy.

Section 6. Quorum. The holders of a majority of the number of outstanding shares of stock of the Corporation entitled to vote thereat, present in person or by proxy at any meeting, shall constitute a quorum, but less than a quorum shall have power to adjourn any meeting from time to time without notice. No change shall be made in this Section 6 without the affirmative vote of the holders of at least a majority of the outstanding shares of stock entitled to vote.

Section 7. Closing of Transfer Books or Fixing of Record Date. For the purposes of determining shareholders entitled to notice of or to vote at any meeting of shareholders or any adjournment thereof, or shareholders entitled to receive payment of any dividend, or in order to make a determination of shareholders for any other proper purpose, the Board of Directors of the Corporation may provide that the stock transfer books shall be closed for a stated period but not to exceed, in any case, fifty (50) days. If the stock transfer books shall be closed for the purpose of determining shareholders entitled to notice of or to vote at a meeting of shareholders, such books shall be closed for at least ten (10) days immediately preceding such meeting. In lieu of closing the stock transfer books, the Board of Directors may fix in advance a date as the record date for any such determination of shareholders, such date in any case to be not more than seventy (70) days and, in case of a meeting of shareholders, not less than ten (10) days prior to the date on which the particular action, requiring such determination of shareholders, is to be taken. When a determination of shareholders entitled to vote at any meeting of shareholders has been made as provided in this section, such determination shall apply to any adjournment thereof.

Section 8. Voting Record. The officer or agent having charge of the stock transfer books for shares of the Corporation shall make, at least ten (10) days before each meeting of shareholders, a complete record of the shareholders entitled to vote at such meeting or any adjournment thereof, arranged in alphabetical order, with the address of and the number of shares held by each, which record, for a period of ten (10) days prior to such meeting, shall be kept on file at the registered office of the Corporation. Such record shall be produced and kept open at the time and place of the meeting and shall be subject to the inspection of any shareholder during the whole time of the meeting for the purposes thereof.

Section 9. Conduct of Proceedings. The Chairman of the Board shall preside at all meetings of the shareholders. In the absence of the Chairman, the President shall preside and in the absence of both, the Executive Vice President shall preside. The members of the Board of Directors present at the meeting may appoint any officer of the Corporation or member of the Board to act as Chairman of any meeting in the absence of the Chairman, the President, or Executive Vice President. The Corporate Secretary of the Corporation, or in his absence, an Assistant Corporate Secretary, shall act as Secretary at all meetings of the shareholders. In the absence of the Corporate Secretary or Assistant Corporate Secretary at any meeting of the shareholders, the presiding officer may appoint any person to act as Secretary of the meeting.

Section 10. Proxies. At all meetings of shareholders, a shareholder may vote in person or by proxy. A shareholder or the shareholder's duly authorized agent or attorney-in-fact may appoint a proxy by (i) executing a proxy in writing or (ii) transmitting or authorizing the transmission of an electronic proxy in any manner permitted by law. Such proxy shall be filed with the Corporate Secretary of the Corporation before or at the time of the meeting.

Section 11. Nomination of Directors and Other Business to be Conducted at Meetings of Shareholders.

(a) *General*. At any meeting of shareholders, only such nominations of individuals for election to the Board of Directors shall be made as shall have been properly made, and only such other business shall be transacted as shall have been properly brought before the meeting, in accordance with this Section 11 and, in the case of a special meeting, Section 2, of this Article II. Certain capitalized terms used in this Section 11 are hereinafter defined in subsection (d).

(b) *Nominations for Director at Annual Meeting*. (i) Subject to the provisions of paragraph (1) of subdivision (j) of Article THIRD of the Articles of Incorporation, nominations for the election of directors may be made at an annual meeting of shareholders only (A) by the Board of Directors or a nominating committee appointed by the Board of Directors or (B) by a Proponent who (1) is an Eligible Shareholder, (2) has complied with the procedures established by this Section 11(b) of Article II and (3) appears at the meeting in person or by qualified representative. For a nomination to be properly made at an annual meeting by a shareholder, the Proponent intending to make such nomination must have delivered timely and proper notice thereof, and timely updates and supplements thereof, in writing to the Corporate Secretary of the Corporation in accordance with, and containing all the information (including the completed questionnaire referred to in subparagraph (iv) below) required by, this Section 11(b) of Article II.

(ii) To be timely,

(A) a Proponent's notice must be delivered to the principal executive offices of the Corporation, to the attention of the Corporate Secretary, not less than 90 or more than 180 days prior to the first anniversary of the date of the preceding year's annual meeting of shareholders; provided, however, that if the date of the annual meeting is advanced more than 30 days prior to or delayed by more than 60 days after such anniversary of the preceding year's annual meeting, then notice by the Proponent to be timely must be delivered to the Corporate Secretary at the principal executive offices of the Corporation not later than the close of business on the later of (1) the 90th day prior to the date of such annual meeting and (2) the 10th day following the date of the first Public Disclosure of the date of such meeting. In no event shall any adjournment or postponement of an annual meeting, or any announcement or notice of such an adjournment or postponement, commence a new time period for the giving of a Proponent's notice required by this Section 11(b) of Article II.

(B) a Proponent's notice shall further be updated and supplemented to the extent necessary to make the information provided or required to be provided therein true, correct and complete, such updates and supplements to be delivered to the principal executive offices of the Corporation, to the attention of the Corporation Secretary, (1) within 5 business days after the record date for the meeting for any change in such information that shall have occurred as of such record date, (2) within 5 business days after any such change that occurs after such record date and on or before the second business day prior to the date of the meeting or any adjournment or postponement thereof, but in no event later than such second business day, and (3) forthwith upon the occurrence of any such change that occurs after the second business day prior to the date of the meeting or any such adjournment or postponement.

(iii) To be in proper form, a Proponent's notice delivered to the Corporate Secretary shall set forth:

(A) <u>Information as to the Proponent and any Shareholder Associated Person</u>

The Proponent Information; and

(B) <u>Information as to each Nominee and any Nominee Associated Person</u>

(1) the name, age, business address, residence address, business telephone number and residence telephone number of such Nominee and the name, business address and residence address of each Nominee Associated Person;

(2) the principal occupation or employment of such Nominee;

(3) the class and number of shares of capital stock of the Corporation that are, directly or indirectly, owned (beneficially and of record) by or on behalf of each Nominee and by or on behalf of any Nominee Associated Person, a specific description of beneficial ownership of such shares, the date such shares were acquired and the investment intent with respect thereto;

(4) without duplication, a description of all direct and indirect pecuniary interests of the Nominee and any Nominee Associated Person in any shares of capital stock of the Corporation;

(5) a description of such Nominee's qualifications to be a director;

(6) a statement as to whether such Nominee would be an independent director, and the basis therefor, under the listing standards of the New York Stock Exchange and the Corporation's internal corporate governance guidelines;

(7) a description of all direct or indirect compensation and other material monetary agreements, arrangements and understandings during the past three years, and any other material relationships, between or among the Proponent and any Shareholder Associated Person, on the one hand, and each proposed Nominee and any Nominee Associated Person, on the other hand, including, without limitation, all information that would be required to be disclosed pursuant to Item 404 of Regulation S-K under the Exchange Act (or any successor regulation) if the Proponent or any Shareholder Associated Person were the “registrant” for purposes of such item and the Nominee or any Nominee Associated Person were a director or executive officer of such registrant; and

(8) any other information with respect to such Nominee or any Nominee Associated Person that would be required to be included in a proxy statement or other filing required to be made in connection with solicitations of proxies for the election of directors in a contested election pursuant to Section 14 of the Exchange Act and the rules and regulations promulgated thereunder (including the written consent of (x) such Nominee to being named in the proxy statement as a Nominee and to serving as a director if elected and (y) such Nominee and each Nominee Associated Person to public disclosure by the Corporation of any or all information relating to such Nominee or such Nominee Associated Person furnished to the Corporation by either thereof or by the Proponent).

(iv) The Proponent's notice, to be in proper form, shall also attach a completed questionnaire (in the form provided by the Corporate Secretary of the Corporation upon request by the Proponent) signed by such Nominee with respect to information of the type required by the Corporation's annual questionnaire for directors and officers of the Corporation in connection with the annual meeting of shareholders and various reports filed with the Securities and Exchange Commission. Such questionnaire shall include a representation and agreement that such Nominee

(A) is not and will not become a party to

(1) any agreement, arrangement or understanding with, and has not given and will not give any commitment or assurance to, any person or entity as to how such Nominee, if elected as a director of the Corporation, will act or vote on any issue or question (any such agreement, arrangement, understanding, commitment or assurance, a "Voting Commitment") that has not been, or shall not have been within three business days thereafter, disclosed to the Corporation or

(2) any Voting Commitment that could limit or interfere with the Nominee's ability to comply, if elected as a director of the Corporation, with such Nominee's fiduciary duties under applicable law,

(B) is not and will not become a party to any agreement, arrangement or understanding with any person or entity other than the Corporation with respect to any direct or indirect compensation, reimbursement or indemnification in connection with service or action as a director of the Corporation that has not been, or shall not have been within three business days thereafter, disclosed to the Corporation, and

(C) in such Nominee's individual capacity and on behalf of any person or entity on whose behalf the nomination is being made, would be in compliance, if elected as a director of the Corporation, and will comply, with applicable law and all applicable corporate governance, conduct and ethics, conflict of interest, corporate opportunity, confidentiality and stock ownership and trading codes, policies and guidelines of the Corporation that are publicly disclosed or which shall have been otherwise disclosed to such Nominee by the Corporate Secretary.

(c) *Other Business Brought before Annual Meeting*. (i) Business other than the nomination of individuals for election as directors may be brought before an annual meeting of shareholders only (A) by or at the direction of the Board of Directors or (B) by a Proponent who (1) is an Eligible Shareholder, (2) has complied with procedures established by this Section 11(c) of Article II and (3) appears at the meeting in person or by qualified representative. For business to be properly brought before an annual meeting of shareholders by a shareholder, the Proponent intending to bring such business before such meeting must have delivered timely and proper notice thereof, and timely updates and supplements thereof, in writing to the Corporate Secretary of the Corporation, in accordance with, and containing all the information required by, this Section 11(c) of Article II, and such business must be a proper matter for shareholder action under the Washington Business Corporation Act.

(ii) To be timely,

(A) a Proponent's notice must be delivered to the principal executive offices of the Corporation, to the attention of the Corporate Secretary, not less than 90 or more than 180 days prior to the first anniversary of the preceding year’s annual meeting of shareholders; provided, however, that if the date of the annual meeting is advanced more than 30 days prior to or delayed by more than 60 days after such anniversary of the preceding year’s annual meeting, then notice by the Proponent to be timely must be delivered to the Corporate Secretary at the principal executive offices of the Corporation not later than the close of business on the later of (1) the 90th day prior to the date of such annual meeting and (2) the 10th day following the date of the first Public Disclosure of the date of such meeting. In no event shall any adjournment or postponement of an annual meeting, or any announcement or notice of such an adjournment or postponement, commence a new time period for the giving of a Proponent’s notice required by this Section 11(c) of Article II; and

(B) a Proponent’s notice shall further be updated and supplemented to the extent necessary to make the information provided or required to be provided therein true, correct and complete, such updates and supplements to be delivered to the principal executive offices of the Corporation, to the attention of the Corporation Secretary, (1) within 5 business days after the record date for the meeting for any change in such information that shall have occurred as of such record date, (2) within 5 business days after any such change that occurs after such record date and on or before the second business day prior to the date of the meeting or any adjournment or postponement thereof, but in no event later than such second business day, and (3) forthwith upon the occurrence of any such change that occurs after the second business day prior to the date of the meeting or any such adjournment or postponement.

(iii) To be in proper form, a Proponent's notice delivered to the Corporate Secretary shall set forth:

(A) Information as to the Proponent and any Shareholder Associated Person

The Proponent Information; and

(B) Information as to Each Item of Business Proposed

(1) a description of such business;

(2) the reasons for transacting such business at the meeting;

(3) a description of any material interest of the Proponent or any Shareholder Associated Person in such business;

(4) a description of any other agreement, arrangement or understanding that has been entered into or is in effect as of the date of the Proponent's notice, between or among the Proponent, any Shareholder Associated Person or any other person, and that relates to such business or the proposal thereof;

(5) the text of any resolutions to be proposed; and

(6) whether the Proponent has communicated with any other shareholder or beneficial owner of shares of stock of the Corporation regarding such business.

(d) *Business Brought before Special Meeting*. (i) As provided in Section 2 of this Article II, the only business that may properly be brought before a special meeting of shareholders shall be that business set forth in the notice of the meeting issued to shareholders by the Corporation.

(ii) Nominations for the election of directors may be made at, and other business may be brought before, a special meeting of shareholders only (A) by or at the direction of the Board of Directors or (B) by a Proponent who is (1) an Eligible Shareholder, (2) either (x) one of the shareholders upon whose demand such meeting shall have been called and who otherwise shall have complied with procedures established by Section 2 of this Article II or (y) if such meeting shall have been called by the Board of Directors for the purpose of electing directors, any other shareholder who shall have complied with the procedures established in this Section 11(d) and (3) in any case, appears at the meeting in person or by qualified representative. For a nomination to be properly made at a special meeting as contemplated in clause (y) above, the Proponent intending to make such nomination must have delivered timely and proper notice thereof, and timely updates and supplements thereof, in writing to the principal executive offices of the Corporation, to the attention of the Corporate Secretary, in accordance with, and containing all the information required by, this Section 11(d).

(iii) To be timely,

(A) the notice delivered by a shareholder described in clause (y) of paragraph (ii)(B)(2) above must be so delivered not later than the 10th day following the date of the first Public Disclosure of the date of the special meeting. In no event shall any adjournment or postponement of a special meeting, or any announcement or notice of such an adjournment or postponement, commence a new time period for the giving of a Proponent's notice required by this Section 11(d) of Article II; and

(B) such notice shall further be updated and supplemented when and as provided in Section 11(b)(ii)(B) of this Article II.

(iv) to be in proper form, the notice delivered by a shareholder described in clause (y) of paragraph (ii)(B)(2) above shall set forth all the information required by Section 11(b)(iii) and (iv) of this Article II.

(e) *Effect of Bylaws*. (i) No individual proposed to be nominated by a shareholder shall be eligible for election or service as a director of the Corporation unless such person is nominated in accordance with the procedures set forth in this Section 11, and, to the extent applicable, Section 2, of Article II. No other business proposed by a shareholder shall be transacted at a meeting of shareholders except in accordance with the procedures set forth in this Section 11, and, to the extent applicable, Section 2, of Article II. The Board of Directors, the Governance Committee of the Board or any other duly authorized committee thereof, the Chairman of the Board or the President shall have the authority to determine whether or not any of the foregoing requirements for any nomination to be properly made and/or any other business to be properly brought before the meeting in accordance with the provisions of this Section 11, and, to the extent applicable, Section 2, shall have been satisfied and, if such determination shall not have been made prior to the meeting, the Chairman of the meeting shall have such authority; it being understood that such authority granted to the Board and the Governance Committee shall include the discretionary authority to waive any such requirement (for any reason or for no reason) in any particular instance and to waive the same in one instance and not in another. If it shall have been so determined, the Chairman of the meeting shall declare to the meeting that any nomination was not properly made and/or that any other business was not properly brought before the meeting, and, in such event, such matter shall not be presented to the meeting, shall not be voted upon and shall be disregarded, notwithstanding that the proposed nomination or other business may have been included in the Corporation's notice of the meeting or in the Corporation's or a shareholder's proxy statement and/or that proxies in respect of such nomination or other business may have been solicited or obtained. Such determination shall be conclusive. Anything herein to the contrary notwithstanding, no waiver of any requirement set forth in this Section 11, or, to the extent applicable, Section 2, of Article II shall extend to or affect such requirement except to the extent so expressly waived, and, except to such extent, such requirement shall remain in full force and effect.

(ii) The requirements of this Section 11 of Article II, and, to the extent applicable, Section 2, shall apply to any nomination to be made and/or any business to be brought before a meeting of shareholders by a shareholder without regard to whether such nomination or other business also is included or intended to be included in the Corporation's proxy statement pursuant to any rule under the Exchange Act or whether such nomination or other business is presented to shareholders by means of a proxy solicitation by any person other than by or on behalf of the Board of Directors or otherwise. Nothing in these Bylaws shall be deemed to affect any rights a shareholder may have under any rule under the Exchange Act to request inclusion of a proposal in the Corporation’s proxy statement. Nothing in these Bylaws shall be deemed to permit any shareholder, or give any shareholder the right, to include, or to have disseminated or described, any proposal in the Corporation’s proxy statement, or to expand any right a shareholder may have under any rule under the Exchange Act to request inclusion of proposed business in the Corporation's proxy materials or reduce the requirements that must be met under such rule to trigger any such right.

(f) *Definitions.*

“Eligible Shareholder” means a shareholder of the Company who, both at the time of giving the notice required by Section 11(b)(i) or Section 11 (c)(i), or the demand required by Section 2(b), as the case may be, and at the time of the related meeting of shareholders and any adjournment or postponement thereof, (i) is either (A) a shareholder of record or (B) a person, not a shareholder of record, who holds shares through a brokerage firm, bank or other nominee and who has proved ownership of such shares in a manner contemplated by Rule 14a-8 under the Exchange Act (whether or not such rule shall be applicable in the particular case) and (ii) is entitled to vote such shares, or is entitled to give instructions as to the voting of such shares, as the case may be, on the matters referred to in such notice or demand.

“Exchange Act” means the Securities Exchange Act of 1934, as amended.

“**Nominee**” means a natural person nominated for election as a director of the Corporation.

“**Nominee Associated Person**” of any Nominee means (i) any affiliate or associate (as such terms are defined for purposes of the Exchange Act) of such Nominee, (ii) any beneficial owner of shares of stock of the Corporation owned of record or beneficially by such Nominee or any affiliate or associate of such Nominee, (iii) any person controlling, controlled by or under common control with such Nominee or other Nominee Associated Person and (iv) any person acting in concert with such Nominee or any of the foregoing.

“Proponent” means a shareholder of the Corporation who intends to make a nomination for director or bring other business before a meeting of shareholders, as the case may be.

“Proponent Information” means:

(i) the name and address of the Proponent and of any Shareholder Associated Person;

(ii) the class and number of shares of capital stock of the Corporation that are, directly or indirectly, owned (beneficially and of record) by or on behalf of the Proponent and by or on behalf of any

Shareholder Associated Person, a specific description of beneficial ownership of such shares, the date such shares were acquired and the investment intent with respect thereto;

(iii) without duplication, a description of all direct and indirect pecuniary interests of the Proponent and any Shareholder Associated Person in any shares of capital stock of the Corporation;

(iv) a description of all purchases and sales of, or other transactions involving in any way, shares of capital stock of the Corporation by or on behalf of the Proponent and by or on behalf of any Shareholder Associated Person during the twenty-four month period prior to the date of the Proponent's notice or demand, as the case may be, including the date of the transactions, the class and number of shares and the consideration (without regard to whether such shares involved were or were not owned by the Proponent or any such person);

(v) any other information with respect to such business, the Proponent and/or any Shareholder Associated Person that would be required to be included in a proxy statement subject to Regulation 14A under the Exchange Act, if such business were being proposed by the Board of Directors of the Corporation;

(vi) a representation as to whether the Proponent intends to deliver a proxy statement and/or form of proxy to shareholders and/or otherwise to solicit proxies from shareholders in support of such proposal;

(vii) a consent by the Proponent and each Shareholder Associated Person to the public disclosure by the Corporation of any or all of the Proponent Information relating to the Proponent or such Shareholder Associated Person, and

(viii) if the Proponent is not the shareholder of record, evidence proving indirect ownership of shares of capital stock in the manner contemplated by Rule 14a-8 under the Exchange Act (whether or not such rule shall be applicable in the particular case).

"**Public Disclosure**" means disclosure made in a press release reported by Dow Jones News Service, Associated Press or a comparable national news service or in a document filed by the Corporation pursuant to Section 13, 14 or 15(d) of the Exchange Act.

"**Shareholder Associated Person**" of any shareholder means (i) any affiliate or associate (as such terms are defined for purposes of the Exchange Act) of the shareholder, (ii) any beneficial owner of shares of stock of the Corporation owned of record or beneficially by such shareholder or any affiliate or associate of such beneficial owner, (iii) any person controlling, controlled by or under common control with such shareholder or any Shareholder Associated Person and (iv) any person acting in concert with such shareholder or any of the foregoing.

As used in these Bylaws, shares "**beneficially owned**" shall mean all shares that a person is deemed to beneficially own under Rules 13d-3 and 13d-5 under the Exchange Act; provided, however, that such person shall be deemed to so own beneficially all shares as to which such personal shall have a right to acquire beneficial ownership at any time in the future.

As used in these Bylaws, "**pecuniary interest**" and "**indirect pecuniary interest**" shall have the meaning assigned thereto in Rule 16a-1(a)(2) under the Exchange Act; provided, however, that with respect to any security or other instrument having a conversion, exercise or similar right that becomes determinable only at a future time or upon the occurrence of a future event, the number or amount to be realized upon conversion or exercise shall be deemed to be the amount that would be realized if convertible or exercisable, and so converted or exercised, at the time the pecuniary interest or indirect pecuniary interest is disclosed to the Corporate Secretary pursuant to these Bylaws.

ARTICLE III.
Board of Directors

Section 1. General Powers. The powers of the Corporation shall be exercised by or under the authority of the Board of Directors, except as otherwise provided by the laws of the State of Washington and the Articles of Incorporation.

Section 2. Number, Tenure and Eligibility. The number of Directors of the Corporation shall be as fixed from time to time by resolution of the Board of Directors, but shall not be more than eleven (11); provided, however, that if the right to elect a majority of the Board of Directors shall have accrued to the holders of the Preferred Stock as provided in paragraph (1) of subdivision (j) of Article THIRD of the Articles of Incorporation, then, during such period as such holders shall have such right, the number of directors may exceed eleven (11). At each Annual Meeting of Shareholders, all directors shall stand for election each year for a term of office to expire at the next succeeding Annual Meeting of Shareholders after their election. Notwithstanding the foregoing, directors elected by the holders of the Preferred Stock in accordance with paragraph (1) of subdivision (j) of Article THIRD of the Articles of Incorporation shall be elected for a term, which shall expire not later than the next Annual Meeting of Shareholders. All directors shall hold office until the expiration of their term of office and until their successors shall have been elected and qualified. No person may be elected or re-elected as a director if at the time of their election or re-election, such person shall have attained the age of seventy-two (72) years. Any director who attains such age while in office shall retire from the Board of Directors effective at the Annual Meeting of Shareholders held in the year in which their then current term expires, and any such director shall not be nominated or re-elected as a director.

Section 3. Regular Meetings. The regular Annual Meeting of the Board of Directors shall be held immediately following the adjournment of the Annual Meeting of the shareholders or as soon as practicable after said Annual Meeting of Shareholders. But, in any event, said regular Annual Meeting of the Board of Directors must be held on either the same day as the Annual Meeting of Shareholders or the next business day following said Annual Meeting of Shareholders. At such meeting the Board of Directors, including directors newly elected, shall organize itself for the coming year, shall elect officers of the Corporation for the ensuing year, and shall transact all such further business as may be necessary or appropriate. The Board shall hold regular quarterly meetings, without call or notice, on such dates as determined by the Board of Directors. At such quarterly meetings the Board of Directors shall transact all business properly brought before the Board.

Section 4. Special Meetings. Special meetings of the Board of Directors may be called by or at the request of the Chairman of the Board, the President, the Executive Vice President, the Lead Director or any three (3) directors. Notice of any special meeting shall be given to each director at least two (2) days in advance of the meeting.

Section 5. Emergency Meetings. In the event of a catastrophe or a disaster causing the injury or death to members of the Board of Directors and the principal officers of the Corporation, any director or officer may call an emergency meeting of the Board of Directors. Notice of the time and place of the emergency meeting shall be given not less than two (2) days prior to the meeting and may be given by any available means of communication. The director or directors present at the meeting shall constitute a quorum for the purpose of filling vacancies determined to exist. The directors present at the emergency meeting may appoint such officers as necessary to fill any vacancies determined to exist. All appointments under this section shall be temporary until a special meeting of the shareholders and directors is held as provided in these Bylaws.

Section 6. Conference by Telephone. The members of the Board of Directors, or of any committee created by the Board, may participate in a meeting of the Board or of the committee by means of a conference telephone or similar communication equipment by means of which all persons participating in the meeting can hear each other at the same time. Participation in a meeting by such means shall constitute presence in person at a meeting.

Section 7. Quorum. A majority of the number of directors shall constitute a quorum for the transaction of business at any meeting of the Board of Directors. The action of a majority of the directors present at a meeting at which a quorum is present shall be the action of the Board.

Section 8. Action Without a Meeting. Any action required by law to be taken at a meeting of the directors of the Corporation, or any action which may be taken at a meeting of the directors or of a committee, may be taken without a meeting if a consent in writing, setting forth the action so taken, shall be signed by all of the directors, or all of the members of the committee, as the case may be. Such consent shall have the same effect as a unanimous vote.

Section 9. Vacancies. Subject to the provisions of paragraph (1) of subdivision (j) of Article THIRD of the Articles of Incorporation, (a) any vacancy occurring in the Board of Directors may be filled by the Board of Directors and any director so elected to fill a vacancy shall be elected for a term of office continuing until the next election of directors by the shareholders; provided, however, if the directors then in office constitute fewer than a quorum of the Board, the affirmative vote of a majority of all directors then in office shall be required fill such vacancy.

Section 10. Resignation of Director. Any director or member of any committee may resign at any time. Such resignation shall be made in writing and shall take effect at the time specified therein. If no time is specified, it shall take effect from the time of its receipt by the Corporate Secretary, who shall record such resignation, noting the day, hour and minute of its reception. The acceptance of a resignation shall not be necessary to make it effective.

Section 11. Removal. Subject to the provisions of paragraph (1) of subdivision (j) of Article THIRD of the Articles of Incorporation, any director may be removed from office at any time, but only for cause and only by the holders of shares of capital stock of the Corporation entitled generally to vote in the election of directors voting together as a single class, at a meeting of shareholders called expressly for that purpose and only if the number of votes cast for the removal of such director exceeds the number of votes cast against such removal. No decrease in the number of directors constituting the Board of Directors shall shorten the term of any incumbent director.

Section 12. Order of Business. The Chairman of the Board shall preside at all meetings of the directors. In the absence of the Chairman, the officer or member of the Board designated by the Board of Directors shall preside. At meetings of the Board of Directors, business shall be transacted in such order as the Board may determine. Minutes of all proceedings of the Board of Directors, or committees appointed by it, shall be prepared and maintained by the Corporate Secretary or an Assistant Corporate Secretary and the original shall be maintained in the principal office of the Corporation.

Section 13. Presumption of Assent. A director of the Corporation who is present at a meeting of the Board of Directors, or of a committee thereof, at which action on any corporate matter is taken, shall be presumed to have assented to the action unless his dissent shall be entered in the minutes of the meeting or unless he shall file his written dissent to such action with the person acting as the Secretary of the meeting before the adjournment thereof or shall forward such dissent by registered mail to the Corporate Secretary of the Corporation immediately after the adjournment of the meeting. Such right to dissent shall not apply to a director who voted in favor of such action.

ARTICLE IV.
Executive Committee
and
Additional Committees

Section 1. Appointment. The Board of Directors, by resolution adopted by a majority of the Board, may designate three or more of its members to constitute an Executive Committee. The designation of such committee and the delegation thereto of authority shall not operate to relieve the Board of Directors, or any member thereof, of any responsibility imposed by law.

Section 2. Authority. The Executive Committee, when the Board of Directors is not in session, shall have and may exercise all of the authority of the Board of Directors including authority to authorize distributions or the issuance of shares of stock, except to the extent, if any, that such authority shall be limited by the resolution appointing the Executive Committee or by law.

Section 3. Tenure. Each member of the Executive Committee shall hold office until the next regular Annual Meeting of the Board of Directors following his designation and until his successor is designated as a member of the Executive Committee.

Section 4. Meetings. Regular meetings of the Executive Committee may be held without notice at such times and places as the Executive Committee may fix from time to time by resolution. Special meetings of the Executive Committee may be called by any member thereof upon not less than two (2) days notice stating the place, date and hour of the meeting, which notice may be written or oral. Any member of the Executive Committee may waive notice of any meeting and no notice of any meeting need be given to any member thereof who attends in person.

Section 5. Quorum. A majority of the members of the Executive Committee shall constitute a quorum for the transaction of business at any meeting thereof. Actions by the Executive Committee must be authorized by the affirmative vote of a majority of the appointed members of the Executive Committee.

Section 6. Action Without a Meeting. Any action required or permitted to be taken by the Executive Committee at a meeting may be taken without a meeting if a consent in writing, setting forth the action so taken, shall be signed by all of the members of the Executive Committee.

Section 7. Procedure. The Executive Committee shall select a presiding officer from its members and may fix its own rules of procedure, which shall not be inconsistent with these Bylaws. It shall keep regular minutes of its proceedings and report the same to the Board of Directors for its information at a meeting thereof held next after the proceedings shall have been taken.

Section 8. Committees Additional to Executive Committee. The Board of Directors may, by resolution, designate one or more other committees, each such committee to consist of two (2) or more of the directors of the Corporation. A majority of the members of any such committee may determine its action and fix the time and place of its meetings unless the Board of Directors shall otherwise provide.

ARTICLE V.
Officers

Section 1. Number. The Board of Directors shall appoint one of its members Chairman of the Board. The Board of Directors shall also appoint a Chief Executive Officer and a President, one of whom may also serve as Chairman, one or more Vice Presidents, a Corporate Secretary, and a Treasurer. The Board of Directors may from time to time appoint such other officers as the Board deems appropriate. The same person may be appointed to more than one office. The Chief Executive Officer shall have the authority to appoint such assistant officers as might be deemed appropriate.

Section 2. Election and Term of Office. The officers of the Corporation shall be elected by the Board of Directors at the Annual Meeting of the Board. Each officer shall hold office until his successor shall have been duly elected and qualified.

Section 3. Removal. Any officer or agent may be removed by the Board of Directors whenever in its judgment the best interests of the Corporation will be served thereby, but such removal shall be without prejudice to contract rights, if any, of the person so removed. Election or appointment of an officer or agent shall not of itself create contract rights.

Section 4. Vacancies. A vacancy in any office because of death, resignation, removal, disqualification or otherwise may be filled by the Board of Directors for the unexpired portion of the term.

Section 5. Powers and Duties. The officers shall have such powers and duties as usually pertain to their offices, except as modified by the Board of Directors, and shall have such other powers and duties as may from time to time be conferred upon them by the Board of Directors.

ARTICLE VI.
Contracts, Checks and Deposits

Section 1. Contracts. The Board of Directors may authorize any officer or officers or agents, to enter into any contract or to execute and deliver any instrument in the name of and on behalf of the Corporation, and such authority may be general or confined to specific instances.

Section 2. Checks/Drafts/Notes. All checks, drafts or other orders for the payment of money, notes or other evidences of indebtedness issued in the name of the Corporation shall be signed by such officer or officers, agent or agents of the Corporation and in such manner as shall from time to time be determined by resolution of the Board of Directors.

Section 3. Deposits. All funds of the Corporation not otherwise employed shall be deposited from time to time to the credit of the Corporation in such banks, trust companies or other depositories as the Board of Directors by resolution may select.

ARTICLE VII.
Certificates for Shares and Their Transfer

Section 1. Certificates for Shares. Certificates representing shares of the Corporation shall be in such form as shall be determined by the Board of Directors and shall contain such information as prescribed by law. Such certificates shall be signed by the President or a Vice President and by either the Corporate

Secretary or an Assistant Corporate Secretary, and sealed with the corporate seal or a facsimile thereof. The signatures of such officers upon a certificate may be facsimiles. The name and address of the person to whom the shares represented thereby are issued, with the number of shares and date of issue, shall be entered on the stock transfer books of the Corporation. All certificates surrendered to the Corporation for transfer shall be cancelled and no new certificate shall be issued until the former certificate for a like number of shares shall have been surrendered and cancelled, except that in case of a lost, destroyed or mutilated certificate a new one may be issued therefor upon such terms and indemnity to the Corporation as the Board of Directors may prescribe.

Section 2. Transfer of Shares. Transfer of shares of the Corporation shall be made only on the stock transfer books of the Corporation by the holder of record thereof or by his legal representative, who shall furnish proper evidence of authority to transfer, or by his attorney thereunto authorized by power of attorney duly executed and filed with the Corporate Secretary of the Corporation, and on surrender for cancellation of the certificate for such shares. The person in whose name shares stand on the books of the Corporation shall be deemed by the Corporation to be the owner thereof for all purposes. The Board of Directors shall have power to appoint one or more transfer agents and registrars for transfer and registration of certificates of stock.

ARTICLE VIII.
Corporate Seal

The seal of the Corporation shall be in such form as the Board of Directors shall prescribe.

ARTICLE IX.
Indemnification

Section 1. Indemnification of Directors and Officers. The Corporation shall indemnify and reimburse the expenses of any person who is or was a director, officer, agent or employee of the Corporation or is or was serving at the request of the Corporation as a director, officer, partner, trustee, employee, or agent of another enterprise or employee benefit plan to the extent permitted by and in accordance with Article SEVENTH of the Company's Articles of Incorporation and as permitted by law.

Section 2. Liability Insurance. The Corporation shall have the power to purchase and maintain insurance on behalf of any person who is or was a director, officer, employee, or agent of the Corporation or is or was serving at the request of the Corporation as a director, officer, employee or agent of another corporation, partnership, joint venture, trust, other enterprise, or employee benefit plan against any liability asserted against him and incurred by him in any such capacity or arising out of his status as such, whether or not the Corporation would have the power to indemnify him against such liability under the laws of the State of Washington.

Section 3. Ratification of Acts of Director, Officer or Shareholder. Any transaction questioned in any shareholders' derivative suit on the ground of lack of authority, defective or irregular execution, adverse interest of director, officer or shareholder, nondisclosure, miscomputation, or the application of improper principles or practices of accounting may be ratified before or after judgment, by the Board of Directors or by the shareholders in case less than a quorum of directors are qualified; and, if so ratified, shall have the same force and effect as if the questioned transaction had been originally duly authorized, and said ratification shall be binding upon the Corporation and its shareholders and shall constitute a bar to any claim or execution of any judgment in respect of such questioned transaction.

ARTICLE X.
Amendments

Except as to Section 6 of Article II of these Bylaws, the Board of Directors may alter or amend these Bylaws at any meeting duly held, the notice of which includes notice of the proposed amendment. Bylaws adopted by the Board of Directors shall be subject to change or repeal by the shareholders; provided, however, that Sections 2 and 11 of Article II, Section 2 of Article III, (other than the provision thereof specifying the number of Directors of the Corporation), and Sections 9 and 11 of Article III and this proviso shall not be altered, amended or repealed, and no provision inconsistent therewith or herewith shall be included in these Bylaws, without the affirmative votes of the holders of at least eighty percent (80%) of the voting power of all the shares of the Voting Stock voting together as a single class.

The undersigned hereby certifies that these Bylaws of Avista Corporation were adopted by the Board of Directors of the Corporation on February 7, 2014.

/s/ Karen S. Feltes

Corporate Secretary

Exhibit 12

AVISTA CORPORATION

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

	Six months ended	Years Ended December 31				
	June 30, 2014	2013	2012	2011	2010	2009
Fixed charges, as defined:						
Interest charges	$ 35,625	$ 75,409	$ 73,633	$ 69,591	$ 72,010	$ 61,361
Amortization of debt expense and premium - net	1,889	3,813	3,803	4,617	4,414	5,673
Interest portion of rentals	1,306	2,762	2,717	2,154	2,027	1,874
Total fixed charges	$ 38,820	$ 81,984	$ 80,153	$ 76,362	$ 78,451	$ 68,908
Earnings, as defined:						
Pre-tax income from continuing operations	$ 122,709	$ 175,524	$ 120,061	$ 160,171	$ 146,105	$ 134,971
Add (deduct):						
Capitalized interest	(1,495)	(3,676)	(2,401)	(2,942)	(298)	(545)
Total fixed charges above	38,820	81,984	80,153	76,362	78,451	68,908
Total earnings	$ 160,034	$ 253,832	$ 197,813	$ 233,591	$ 224,258	$ 203,334
Ratio of earnings to fixed charges	4.12	3.10	2.47	3.06	2.86	2.95

Exhibit 15

August 8, 2014

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 June 30, 2014 and 2013, as indicated in our report dated August 8, 2014; 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 June 30, 2014, is incorporated by reference in Registration Statement Nos. 2-81697, 2-94816, 033-54791, 333-03601, 333-22373, 333-33790, 333-47290, 333-126577, and 333-179042 on Form S-8; in Registration Statement Nos. 333-187306 and 333-177981 on Form S-3; and in Registration Statement No 333-194310 on Form S-4/A filed on May 8, 2014.

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: August 8, 2014

/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: August 8, 2014

/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 June 30, 2014 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 8, 2014

/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