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

Form 10-Q

(Mark One)

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

FOR THE QUARTERLY PERIOD ENDED September 30, 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 x No ☐

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

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

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

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

As of October 31, 2014, 62,239,441 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, specifically related to the Pacific Northwest refund proceedings;
- the outcome of legal proceedings and other contingencies;
- changes in environmental and endangered species laws, regulations, decisions and policies, including present and potential environmental remediation costs and our compliance with these matters;
- wholesale and retail competition including alternative energy sources, growth in customer-owned power resource technologies that displace utility-supplied energy or that may be sold back to the utility, and alternative energy suppliers and delivery arrangements;
- growth or decline of our customer base and the extent to which new uses for our services may materialize or existing uses may decline;
- the ability to comply with the terms of the licenses for our hydroelectric generating facilities at cost-effective levels;
- severe weather or natural disasters that can disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies and support services;
- explosions, fires, accidents, mechanical breakdowns, avalanches or other incidents that may impair assets and may disrupt operations of any of our generation facilities, transmission and distribution systems or other operations;
- public injuries or damage arising from or allegedly arising from our operations;
- blackouts or disruptions of interconnected transmission systems (the regional power grid);
- disruption to information systems, automated controls and other technologies that we rely on for our operations, communications and customer service;
- terrorist attacks, cyber attacks or other malicious acts that may disrupt or cause damage to our utility assets or to the national economy in general, including any effects of terrorism, cyber attacks or vandalism that damage or disrupt information technology systems;
- cyber attacks or other potential lapses that result in unauthorized disclosure of private information, which could result in liabilities against us, costs to investigate, remediate and defend, and damage to our reputation;
- delays or changes in construction costs, and/or our ability to obtain required permits and materials for present or prospective facilities;
- changes in the costs to implement new information technology systems and/or obstacles that impede our ability to complete such projects timely and effectively;
- changes in the long-term global and our utilities' service area climates, which can affect, among other things, customer demand patterns and the volume and timing of streamflows to our hydroelectric resources;
- changes in industrial, commercial and residential growth and demographic patterns in our service territory or changes in demand by significant customers;
- the loss of key suppliers for materials or services or disruptions to the supply chain;
- default or nonperformance on the part of any parties from which we purchase and/or sell capacity or energy;
- deterioration in the creditworthiness of our customers;
- potential decline in our credit ratings, with effects including impeded access to capital markets, higher interest costs, and restrictive covenants in our financing arrangements and wholesale energy contracts;
- increasing health care costs and the resulting effect on employee injury costs and health insurance provided to our employees and retirees;
- increasing costs of insurance, more restrictive coverage terms and our ability to obtain insurance;
- work force issues, including changes in collective bargaining unit agreements, strikes, work stoppages, the loss of key executives, availability of workers in a variety of skill areas, and our ability to recruit and retain employees;
- the potential effects of negative publicity regarding business practices, whether true or not, which could result in litigation or a decline in our common stock price;
- changes in technologies, possibly making some of the current technology obsolete;

- changes in tax rates and/or policies;
- changes in interest rates that affect borrowing costs, our ability to effectively hedge interest rates for anticipated debt issuances, variable interest rate borrowing and the extent that we recover interest costs through utility operations;
- potential difficulties in integrating acquired operations and in realizing expected opportunities, diversions of management resources and losses of key employees, challenges with respect to operating new businesses and other unanticipated risks and liabilities;
- changes in our strategic business plans, which may be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses and the extent of our business development efforts where potential future business is uncertain;
- compliance with extensive federal, state and local legislation and regulation, including numerous environmental, health, safety and other laws and regulations that affect our operations and costs;
- our ability to fully collect the indemnification escrow amounts because of information that was covered under management's representations and warranties related to the Ecova sale which could be inaccurate or incomplete at the time of sale, or because of new information which could be identified subsequent to the sale date, and
- adverse impacts to our Alaska operations because a majority of the hydroelectric power generation for such operations is provided by a single facility that is subject to a long-term power purchase agreement; hence any issues that negatively affect this facility’s ability to generate or transmit power, 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.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

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

	2014	2013
Operating Revenues:		
Utility revenues	$ 291,262	$ 278,473
Non-utility revenues	10,296	11,004
Total operating revenues	301,558	289,477
Operating Expenses:		
Utility operating expenses:		
Resource costs	131,588	131,136
Other operating expenses	72,509	69,596
Depreciation and amortization	33,294	29,823
Taxes other than income taxes	21,000	18,712
Non-utility operating expenses:		
Other operating expenses	10,251	10,212
Depreciation and amortization	154	171
Total operating expenses	268,796	259,650
Income from continuing operations	32,762	29,827
Interest expense	18,642	19,168
Interest expense to affiliated trusts	113	117
Capitalized interest	(1,212)	(820)
Other income-net	(2,608)	(488)
Income from continuing operations before income taxes	17,827	11,850
Income tax expense	7,301	3,367
Net income from continuing operations	10,526	8,483
Net income (loss) from discontinued operations (Note 5)	(55)	3,448
Net income	10,471	11,931
Net income attributable to noncontrolling interests	(20)	(518)
Net income attributable to Avista Corp. shareholders	$ 10,451	$ 11,413

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (continued)

Avista Corporation

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

	2014	2013
Amounts attributable to Avista Corp. shareholders:		
Net income from continuing operations attributable to Avista Corp. shareholders	$ 10,506	$ 8,450
Net income (loss) from discontinued operations attributable to Avista Corp. shareholders	(55)	2,963
Net income attributable to Avista Corp. shareholders	$ 10,451	$ 11,413
Weighted-average common shares outstanding (thousands), basic	63,934	59,994
Weighted-average common shares outstanding (thousands), diluted	64,244	60,032
Earnings per common share attributable to Avista Corp. shareholders, basic:		
Earnings per common share from continuing operations	$ 0.16	$ 0.14
Earnings per common share from discontinued operations	—	0.05
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 0.16	$ 0.19
Earnings per common share attributable to Avista Corp. shareholders, diluted:		
Earnings per common share from continuing operations	$ 0.16	$ 0.14
Earnings per common share from discontinued operations	—	0.05
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 0.16	$ 0.19
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 Nine Months Ended September 30
Dollars in thousands, except per share amounts
(Unaudited)

	2014	2013
Operating Revenues:		
Utility revenues	$ 1,031,491	$ 1,007,319
Non-utility revenues	29,225	30,145
Total operating revenues	1,060,716	1,037,464
Operating Expenses:		
Utility operating expenses:		
Resource costs	481,007	487,277
Other operating expenses	207,195	200,824
Depreciation and amortization	95,200	86,783
Taxes other than income taxes	70,513	66,137
Non-utility operating expenses:		
Other operating expenses	20,514	28,972
Depreciation and amortization	452	536
Total operating expenses	874,881	870,529
Income from continuing operations	185,835	166,935
Interest expense	55,933	57,854
Interest expense to affiliated trusts	336	352
Capitalized interest	(2,707)	(2,702)
Other income-net	(8,263)	(4,439)
Income from continuing operations before income taxes	140,536	115,870
Income tax expense	51,274	41,929
Net income from continuing operations	89,262	73,941
Net income from discontinued operations (Note 5)	70,772	6,821
Net income	160,034	80,762
Net income attributable to noncontrolling interests	(213)	(1,351)
Net income attributable to Avista Corp. shareholders	$ 159,821	$ 79,411

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (continued)

Avista Corporation

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

	2014	2013
Amounts attributable to Avista Corp. shareholders:		
Net income from continuing operations attributable to Avista Corp. shareholders	$ 89,236	$ 73,882
Net income from discontinued operations attributable to Avista Corp. shareholders	70,585	5,529
Net income attributable to Avista Corp. shareholders	$ 159,821	$ 79,411
Weighted-average common shares outstanding (thousands), basic	61,413	59,933
Weighted-average common shares outstanding (thousands), diluted	61,625	59,964
Earnings per common share attributable to Avista Corp. shareholders, basic:		
Earnings per common share from continuing operations	$ 1.45	$ 1.23
Earnings per common share from discontinued operations	1.15	0.09
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 2.60	$ 1.32
Earnings per common share attributable to Avista Corp. shareholders, diluted:		
Earnings per common share from continuing operations	$ 1.45	$ 1.23
Earnings per common share from discontinued operations	1.14	0.09
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 2.59	$ 1.32
Dividends declared per common share	$ 0.9525	$ 0.915

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

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

	2014	2013
Net income	$ 10,471	$ 11,931
Other Comprehensive Income (Loss):		
Unrealized investment losses - net of taxes of $0 and $(233), respectively	—	(395)
Reclassification adjustment for realized gains on investment securities included in net income from discontinued operations - net of taxes of $0 and $(1), respectively	—	(1)
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $60 and $99, respectively	112	184
Total other comprehensive income (loss)	112	(212)
Comprehensive income	10,583	11,719
Comprehensive income attributable to noncontrolling interests	(20)	(518)
Comprehensive income attributable to Avista Corporation shareholders	$ 10,563	$ 11,201

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

	2014	2013
Net income	$ 160,034	$ 80,762
Other Comprehensive Income (Loss):		
Unrealized investment gains/(losses) - net of taxes of $664 and $(993), respectively	1,126	(1,687)
Reclassification adjustment for realized gains on investment securities included in net income from discontinued operations - net of taxes of $(1) and $(8), respectively	(2)	(12)
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 $181 and $297, respectively	335	551
Total other comprehensive income (loss)	1,921	(1,148)
Comprehensive income	161,955	79,614
Comprehensive income attributable to noncontrolling interests	(213)	(1,351)
Comprehensive income attributable to Avista Corporation shareholders	$ 161,742	$ 78,263

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands
(Unaudited)

	September 30, 2014	December 31, 2013
Assets:		
Current Assets:		
Cash and cash equivalents	$ 10,391	$ 82,574
Accounts and notes receivable-less allowances of $4,331 and $44,309, respectively	124,550	221,343
Utility energy commodity derivative assets	3,334	3,022
Regulatory asset for utility derivatives	1,724	10,829
Investments and funds held for clients	—	96,688
Materials and supplies, fuel stock and natural gas stored	69,941	44,946
Deferred income taxes	8,316	24,788
Income taxes receivable	8,428	7,783
Other current assets	38,520	57,706
Total current assets	265,204	549,679
Net Utility Property:		
Utility plant in service	4,655,329	4,290,464
Construction work in progress	205,572	160,323
Total	4,860,901	4,450,787
Less: Accumulated depreciation and amortization	1,322,927	1,248,362
Total net utility property	3,537,974	3,202,425
Other Non-current Assets:		
Investment in exchange power-net	12,046	13,883
Investment in affiliated trusts	11,547	11,547
Goodwill	55,877	76,257
Intangible assets-net of accumulated amortization of $0 and $36,634, respectively	—	39,576
Long-term energy contract receivable of Spokane Energy	31,405	40,619
Other property and investments-net	41,331	58,555
Total other non-current assets	152,206	240,437
Deferred Charges:		
Regulatory assets for deferred income tax	64,322	71,421
Regulatory assets for pensions and other postretirement benefits	151,647	156,984
Other regulatory assets	121,760	102,915
Non-current utility energy commodity derivative assets	1,693	854
Non-current regulatory asset for utility derivatives	13,153	23,258
Other deferred charges	28,387	13,950
Total deferred charges	380,962	369,382
Total assets	$ 4,336,346	$ 4,361,923

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

Dollars in thousands
(Unaudited)

	September 30, 2014	December 31, 2013
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 82,366	$ 182,088
Client fund obligations	—	99,117
Current portion of long-term debt and capital leases	6,471	358
Current portion of nonrecourse long-term debt of Spokane Energy	5,666	16,407
Short-term borrowings	35,000	171,000
Utility energy commodity derivative liabilities	5,009	10,875
Income taxes payable	7,581	697
Other current liabilities	128,726	144,798
Total current liabilities	270,819	625,340
Long-term debt and capital leases	1,412,211	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	254,162	242,850
Pensions and other postretirement benefits	95,037	122,513
Deferred income taxes	640,260	535,343
Other non-current liabilities and deferred credits	120,553	130,318
Total liabilities	2,844,589	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; 62,838,628 and 60,076,752 shares outstanding, respectively	1,007,764	896,993
Accumulated other comprehensive loss	(3,898)	(5,819)
Retained earnings	488,342	407,092
Total Avista Corporation shareholders’ equity	1,492,208	1,298,266
Noncontrolling Interests	(451)	20,001
Total equity	1,491,757	1,318,267
Total liabilities and equity	$ 4,336,346	$ 4,361,923

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

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

	2014	2013
Operating Activities:		
Net income (continuing and discontinued operations)	$ 160,034	$ 80,762
Non-cash items included in net income:		
Depreciation and amortization	102,899	98,793
Provision for deferred income taxes	111,335	16,512
Power and natural gas cost deferrals, net	(17,956)	(10,149)
Amortization of debt expense	2,799	2,841
Amortization of investment in exchange power	1,838	1,838
Stock-based compensation expense	6,261	4,718
Equity-related AFUDC	(6,426)	(4,341)
Pension and other postretirement benefit expense	17,381	31,894
Amortization of Spokane Energy contract	9,214	8,470
Write-off of Reardan wind generation capitalized costs	—	2,534
Gain on sale of Ecova	(161,100)	—
Other	14,568	6,889
Contributions to defined benefit pension plan	(32,000)	(44,000)
Changes in certain current assets and liabilities:		
Accounts and notes receivable	64,761	50,681
Materials and supplies, fuel stock and natural gas stored	(22,979)	(9,388)
Other current assets	3,447	(23,165)
Accounts payable	(22,450)	(23,756)
Income taxes payable	6,885	303
Other current liabilities	27,203	10,966
Net cash provided by operating activities	265,714	202,402
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(229,764)	(220,712)
Other capital expenditures	(6,316)	(1,725)
Federal grant payments received	2,191	2,631
Cash received in acquisition, net of cash paid	15,007	—
Decrease (increase) in funds held for clients	(18,931)	11,723
Purchase of securities available for sale	(12,267)	(35,949)
Sale and maturity of securities available for sale	14,612	16,955
Proceeds from sale of Ecova, net of cash sold	229,903	—
Other	(1,194)	(6,481)
Net cash used in investing activities	(6,759)	(233,558)

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

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

	2014	2013
Financing Activities:		
Net increase (decrease) in short-term borrowings	$ (136,000)	$ 14,000
Borrowings from Ecova line of credit	—	3,000
Repayment of borrowings from Ecova line of credit	(46,000)	(7,000)
Proceeds from issuance of long-term debt	75,000	90,000
Redemption and maturity of long-term debt	(39,367)	(415)
Maturity of nonrecourse long-term debt of Spokane Energy	(12,172)	(11,115)
Cash received for settlement of interest rate swap agreements	—	2,901
Issuance of common stock, net of issuance costs	3,425	4,479
Repurchase of common stock	(60,963)	—
Cash dividends paid	(58,552)	(54,963)
Increase in client fund obligations	16,216	7,375
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	2,325	(591)
Net cash provided by (used in) financing activities	(331,138)	47,671
Net increase (decrease) in cash and cash equivalents	(72,183)	16,515
Cash and cash equivalents at beginning of period	82,574	75,464
Cash and cash equivalents at end of period	$ 10,391	$ 91,979
Supplemental Cash Flow Information:		
Cash paid during the period:		
Interest	$ 44,886	$ 45,633
Income taxes (net of refunds of $35,167 and $5,001, respectively)	22,451	33,522
Non-cash financing and investing activities:		
Accounts payable for capital expenditures	6,945	4,313
Valuation adjustment for redeemable noncontrolling interests	(15,873)	3,246
Receivable for escrow amounts associated with the sale of Ecova	13,567	—
Non-cash stock issuance for acquisition of AERC	150,075	—

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS

Avista Corporation

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

	2014	2013
Common Stock, Shares:		
Shares outstanding at beginning of period	60,076,752	59,812,796
Shares issued	4,685,953	216,413
Shares repurchased	(1,924,077)	—
Shares outstanding at end of period	62,838,628	60,029,209
Common Stock, Amount:		
Balance at beginning of period	$ 896,993	$ 889,237
Equity compensation expense	6,061	4,490
Issuance of common stock, net of issuance costs	153,501	4,479
Repurchase of common stock	(30,794)	—
Equity transactions of consolidated subsidiaries	(1,062)	(7)
Payment to option holders and redeemable noncontrolling interests for sale of Ecova	(20,871)	—
Excess tax benefits	3,936	—
Balance at end of period	1,007,764	898,199
Accumulated Other Comprehensive Loss:		
Balance at beginning of period	(5,819)	(6,700)
Other comprehensive income (loss)	1,921	(1,148)
Balance at end of period	(3,898)	(7,848)
Retained Earnings:		
Balance at beginning of period	407,092	376,940
Net income attributable to Avista Corporation shareholders	159,821	79,411
Cash dividends paid (common stock)	(58,552)	(54,963)
Repurchase of common stock	(30,169)	—
Valuation adjustments and other noncontrolling interests activity	10,150	(2,335)
Balance at end of period	488,342	399,053
Total Avista Corporation shareholders' equity	1,492,208	1,289,404
Noncontrolling Interests:		
Balance at beginning of period	20,001	17,658
Net income attributable to noncontrolling interests	217	1,232
Deconsolidation of noncontrolling interests related to sale of Ecova	(23,612)	—
Other	2,943	2,163
Balance at end of period	(451)	21,053
Total equity	$ 1,491,757	$ 1,310,457
Redeemable Noncontrolling Interests:		
Balance at beginning of period	$ 15,889	$ 4,938
Net income (loss) attributable to noncontrolling interests	(4)	119
Purchase of subsidiary noncontrolling interests	(12)	(379)
Valuation adjustments and other noncontrolling interests activity	(15,873)	3,652
Balance at end of period	$ —	$ 8,330

The Accompanying Notes are an Integral Part of These Statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

The accompanying condensed consolidated financial statements of Avista Corporation (Avista Corp. or the Company) for the interim periods ended September 30, 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 primarily an electric and natural gas utility with certain other business ventures. Avista Utilities is an operating division of Avista Corp., comprising the regulated utility operations in the Pacific Northwest. Avista Utilities provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Utilities also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Utilities has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Utilities also supplies electricity to a small number of customers in Montana, most of whom are employees who operate Avista Utilities' Noxon Rapids generating facility.

On July 1, 2014, Avista Corp. completed its acquisition of Alaska Energy and Resources Company (AERC), and as of that date, AERC is a wholly-owned subsidiary of Avista Corp. The primary subsidiary of AERC is Alaska Electric Light and Power Company (AEL&P), comprising the regulated utility operations in Alaska. Beginning with the three months ended September 30, 2014, the results of AERC are included in the overall results of Avista Corp. See Note 4 for information regarding the acquisition of AERC.

Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility businesses, except Spokane Energy, LLC (Spokane Energy). During the first half of 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 and 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, as of June 30, 2014 and for all subsequent reporting periods there are no balance sheet amounts included for Ecova. 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 nine months ended September 30 (dollars in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Utility taxes	$ 11,716	$ 10,901	$ 43,923	$ 41,045

Other Income-Net

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Interest income	$ 154	$ 124	$ 678	$ 620
Interest income on regulatory deferrals	59	27	154	48
Equity-related AFUDC	2,189	1,595	6,426	4,341
Net gain/(loss) on investments	(27)	(1,299)	118	(1,543)
Other income	233	41	887	973
Total	$ 2,608	$ 488	$ 8,263	$ 4,439

The prior period amounts included in the table above were revised to include only the amounts related to continuing operations. All other amounts were 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 September 30, 2014 and December 31, 2013 (dollars in thousands):

	September 30, 2014	December 31, 2013
Materials and supplies	$ 31,226	$ 28,747
Fuel stock	5,170	3,170
Natural gas stored	33,545	13,029
Total	$ 69,941	$ 44,946

Investments and Funds Held for Clients and Client Fund Obligations

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

Investments and funds held for clients as of December 31, 2013 were 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 was less than cost, and whether it had plans to sell the security or it was more-likely-than not that the Company would 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 nine months ended September 30 (dollars in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Proceeds from sales, maturities and calls	$ —	$ 1,825	$ 14,612	$ 16,955
Gross realized gains	—	2	3	20
Gross realized losses (1)	—	—	(735)	—

(1) The gross realized losses for the nine months ended September 30, 2014 were included in the determination of the gain on the 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. Avista Corp. will use November 30, 2014 for its annual evaluation of goodwill related to AEL&P and the other businesses for 2014.

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

	Ecova	AEL&P	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)
Goodwill acquired during the year	—	50,631	—	—	50,631
Balance as of September 30, 2014	$ —	$ 50,631	$ 12,979	$ (7,733)	$ 55,877

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. The goodwill acquired during the year relates to the acquisition of AERC and the goodwill associated with this acquisition is not deductible for tax purposes. See Note 4 for information regarding this business acquisition and Note 13 regarding the Company's reportable segments.

Intangible Assets

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Intangible asset amortization	$ —	$ 2,765	$ 5,898	$ 8,442

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 September 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 energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. The orders provide for Avista Utilities to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Condensed Consolidated Statements of Income. Realized gains or losses are recognized in the periods of delivery, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rates cases. Regulatory assets are assessed regularly and are probable for recovery through future rates.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as derivative assets or liabilities at estimated fair value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives are accounted for on the accrual basis until they are settled or realized, unless there is a decline in the fair value of the contract that is determined to be other-than-temporary.

For interest rate swap agreements, each period Avista Utilities records all mark-to-market gains and losses for its interest rate swaps agreements as assets and liabilities and records offsetting regulatory assets and liabilities, such that there is no income statement impact. This is similar to the treatment of energy commodity derivatives described above. Upon settlement of interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the term of the associated debt.

Fair Value Measurements

Fair value represents the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Energy commodity derivative assets and liabilities, investments and funds held for clients, deferred compensation assets, as well as derivatives related to interest rate swap agreements and foreign currency exchange contracts, are reported at estimated fair value on the Condensed Consolidated Balance Sheets. See Note 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 was 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 September 30, 2014 and December 31, 2013 (dollars in thousands):

	September 30, 2014	December 31, 2013
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $(2,099) and $(2,280), respectively	$ (3,898)	$ (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	$ (3,898)	$ (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 nine months ended September 30 (dollars in thousands):

Details about Accumulated Other Comprehensive Loss Components	Amounts Reclassified from Accumulated Other Comprehensive Loss: Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013	Affected Line Item in Statement of Income
Realized gains on investment securities	$ —	$ 2	$ 3	$ 20	(a)
Realized losses on investment securities	—	—	(735)	—	(a)
	—	2	(732)	20	Total before tax
	—	(1)	272	(8)	Tax benefit (expense) (a)
	$ —	$ 1	$ (460)	$ 12	Net of tax
Amortization of defined benefit pension items					
Amortization of net loss	$ (1,951)	$ (4,891)	$ (5,855)	$ (14,673)	(b)
Adjustment due to effects of regulation	1,779	4,608	5,339	13,825	(b)
	(172)	(283)	(516)	(848)	Total before tax
	60	99	181	297	Tax benefit
	$ (112)	$ (184)	$ (335)	$ (551)	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.

In addition to the hydroelectric project licenses identified above for Avista Utilities, the requirements of section 10(d) of the FPA also apply to the Lake Dorothy, the Annex Creek and the Salmon Creek licenses, which were all acquired in the AERC acquisition. The Company is still evaluating these licenses to determine an appropriate amount of appropriated retained earnings to record and this analysis is expected to be completed in 2015. The Company does not expect this to result in a material amount of appropriated retained earnings.

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

	September 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,
- the hydroelectric licensing requirements of section 10(d) of the FPA, and
- certain requirements under the OPUC approval of the AERC acquisition, which does not permit one-time or special dividends from AERC to Avista Corp. and which does not permit Avista Utilities' total equity to total capitalization to be less than 40 percent, without approval from the OPUC. The OPUC approval does allow for special or one-time dividends during the first year after closing to recapitalize AERC as part of the transaction and it also allows for regular distributions of AERC earnings to Avista Corp. as long as AERC remains sufficiently capitalized and insured.

Under the covenant applicable to the Company's committed line of credit agreement, which does not permit the ratio of “consolidated total debt” to “consolidated total capitalization” to be greater than 65 percent at any time, the amount of retained earnings available for dividends at September 30, 2014 was limited to approximately $441.1 million.

Under the requirements of the OPUC approval of the AERC acquisition as outlined above, the amount available for dividends at September 30, 2014 was limited to approximately $291.0 million.

Stock Repurchase Program

On June 13, 2014, Avista Corp.'s Board of Directors approved a program to repurchase up to 4 million shares of the Company’s outstanding common stock, assuming the closure of the Ecova transaction. Repurchases of common stock under this program commenced on July 7, 2014 and the program expires on December 31, 2014. The Company can 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 October 31, 2014, the Company has repurchased 2,529,615 shares at a total cost of $79.9 million and an average cost of $31.57 per share. All repurchased shares revert to the status of authorized but unissued shares.

The following table provides information about share repurchases that Avista Corp. made during the three months ended September 30, 2014 (in thousands, except per share amounts):

	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet Be Purchased Under the Program
July 1 to July 31, 2014	292	$ 32.30	292	3,708
August 1 to August 31, 2014	927	31.50	927	2,781
September 1 to September 30, 2014	705	31.67	705	2,076
Total	1,924	$ 31.68	1,924	2,076

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 or a cumulative adjustment to opening retained earnings may have to be recorded. The Company is currently evaluating this standard and cannot, at this time, estimate the potential impact to its future financial condition, results of operations and cash flows.

In August 2014, the FASB issued ASU No. 2014-15, "Presentation of Financial Statements - Going Concern (ASC Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern." The new standard provides guidance around management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern within one year of the date the financial statements are issued. The Company must provide certain disclosures if conditions or events raise substantial doubt about the Company’s ability to continue as a going concern. The new standard is effective for periods beginning after December 15, 2016; 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.

NOTE 3. VARIABLE INTEREST ENTITIES

Lancaster Power Purchase Agreement

The Company has a power purchase agreement (PPA) for all the output of the Lancaster Plant, a 270 MW natural gas-fired combined cycle combustion turbine plant located in Kootenai County, 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 $280.9 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-driven power generation 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 10th 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 $590.6 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 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 (CBJ), Alaska. As of July 1, 2014, AEL&P had 60 full-time employees. Its rate base for 2013 was $109.0 million. AEL&P 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. AEL&P 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 the acquisition was to expand and diversify Avista Corp.'s energy assets and deliver long-term value to its customers, communities and investors.

In connection with the closing, Avista Corp. issued 4,500,014 new shares of common stock to the shareholders of AERC based on a contractual price formula which was $32.46 per share. The exchange for AERC shares for Avista Corp. shares reflects a purchase price of $170.0 million, plus acquired cash, less outstanding debt and other closing adjustments.

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

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 the calculated $32.46 per share common stock price)		
Gross contract price	$	170,000
Acquired cash		19,704
Acquired debt (excluding capital lease obligation)		(38,832)
Other closing adjustments		(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 - gross totals $3,928	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	50,631
Other deferred charges and non-current assets	5,368
Total other non-current assets	66,370
Total assets	$ 281,352
Liabilities Assumed:	
Current Liabilities:	
Accounts payable	$ 700
Current portion of long-term debt and capital lease obligations	3,773
Other current liabilities	2,902
Total current liabilities	7,375
Long-term debt	37,227
Capital lease obligations	68,840
Other non-current liabilities and deferred credits	13,138
Total liabilities	$ 126,580
Total identifiable net assets acquired	$ 154,772

The goodwill associated with this acquisition is not deductible for tax purposes.

The majority of AERC’s operations are subject to the rate-setting authority of the Regulatory Commission of Alaska (RCA) and are accounted for pursuant to 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 are assumed to approximate their carrying values. There were not any identifiable intangible assets associated with this acquisition. The excess of the purchase consideration over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill at the acquisition date. The goodwill reflects the value paid for the expected continued growth of a rate-regulated business located in a defined service area with a constructive regulatory environment, the attractiveness of stable, growing cash flows, as well as providing a platform for potential future growth outside of the rate-regulated electric utility in Alaska.

The following table summarizes the supplemental pro forma revenue, net income and earnings per share information for the three and nine months ended September 30 related to the acquisition of AERC as if the acquisition had occurred on January 1, 2013. The revenues and net income for AERC for the three months ended September 30, 2014 are actual results and the results for the first nine months of 2013 and the first six months of 2014 are pro forma results (dollars in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Actual Avista Corp. revenues from continuing operations (excluding AERC)	$ 292,334	$ 289,477	$ 1,051,492	$ 1,037,464
Supplemental pro forma AERC revenues (1)	9,224	9,309	35,319	31,243
Total supplemental pro forma revenues	301,558	298,786	1,086,811	1,068,707
Actual AERC revenues included in Avista Corp. revenues (1)	9,224	—	9,224	—
Actual Avista Corp. net income from continuing operations attributable to Avista Corp. shareholders (excluding AERC)	9,982	8,450	88,712	73,882
Actual Avista Corp. net income from discontinued operations attributable to Avista Corp. shareholders	(55)	2,963	70,585	5,529
Adjustment to Avista Corp.'s net income for acquisition costs (net of tax) (2)	401	66	838	(1,828)
Supplemental pro forma AERC net income (1) (5)	524	199	6,151	7,634
Total supplemental pro forma net income	10,852	11,678	166,286	85,217
Actual AERC net income included in Avista Corp. net income (1)	$ 524	$ —	$ 524	$ —
Pro forma weighted-average common shares outstanding (thousands), basic (3)	63,934	64,494	64,413	64,433
Pro forma weighted-average common shares outstanding (thousands), diluted (3)	64,244	64,532	64,625	64,464
Pro forma earnings per common share attributable to Avista Corp. shareholders				
Total pro forma earnings per common share attributable to Avista Corp. shareholders, basic	$ 0.17	$ 0.18	$ 2.58	$ 1.32
Total pro forma earnings per common share attributable to Avista Corp. shareholders, diluted (4)	$ 0.17	$ 0.18	$ 2.57	$ 1.32

(1) AERC was acquired on July 1, 2014 and only the supplemental revenues and net income from the third quarter of 2014 were included in the actual results of Avista Corp. for the three and nine months ended September 30.

(2) This adjustment is to treat all transaction costs incurred since the beginning of the transaction to January 1, 2013 as if the acquisition occurred on that date and to remove them from the periods in which they actually occurred. The transaction costs were expensed and presented in the Condensed Consolidated Statements of Income in other operating expenses within utility operating expenses. Since the start of the planned transaction through September 30, 2014, Avista Corp. has expensed $2.9 million (pre-tax) in total transaction fees associated with the transaction. In addition to the amounts expensed, Avista Corp. has included $0.4 million in fees through September 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 nine months ended September 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, 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 $16.8 million (5 percent of the purchase price) will be held in escrow for 15 months from the closing of the transaction to satisfy certain indemnification obligations under the merger agreement, and an additional $1.5 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 Section 338(h)(10) of the Internal Revenue Code (Code) of 1986, as amended, with respect to the purchase and sale of Ecova to allocate the merger consideration among the assets of Ecova deemed to have been acquired in the merger.

When all escrow amounts are released, the sales transaction is expected to provide cash proceeds to Avista Corp., net of debt, payment to option and minority holders, income taxes and transaction expenses, of $133.2 million (see reconciliation below) and result in a net gain of $68.0 million. The Company expects to receive the full amount of its portion of the escrow accounts; therefore, the full amounts were 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 $16.8 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 nine months ended September 30 (dollars in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Revenues	$ —	$ 46,398	$ 87,534	$ 133,365
Gain on sale of Ecova (1)	—	—	161,100	—
Transaction expenses and accelerated employee benefits (2)	86	—	9,062	—
Gain on sale of Ecova, net of transaction expenses	(86)	—	152,038	—
Income (loss) before income taxes	(86)	5,540	156,513	10,999
Income tax expense (benefit)	(31)	2,092	85,741	4,178
Net income (loss) from discontinued operations	(55)	3,448	70,772	6,821
Net income attributable to noncontrolling interests	—	(485)	(187)	(1,292)
Net income (loss) from discontinued operations attributable to Avista Corp. shareholders	$ (55)	$ 2,963	$ 70,585	$ 5,529

(1) This represents the gross gain recorded to discontinued operations. The gain net of taxes and transactions expenses is $68.0 million.

(2) This represents Avista Corp.'s portion of the total transaction expenses. All transaction expenses paid on the Ecova sale were $11.0 million, of which $5.4 million were withheld from the net proceeds and the remainder were paid during the second and third quarter of 2014. The transaction expenses were for legal, accounting and other consulting fees and the accelerated employee benefits related to employee stock options which were settled in accordance with the Ecova equity plan.

NOTE 6. DERIVATIVES AND RISK MANAGEMENT

The below disclosures in Note 6 apply only to Avista Utilities; AERC and its primary subsidiary AEL&P do not enter into derivative instruments.

Energy Commodity Derivatives

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

As part of the Company's resource procurement and management operations in the electric business, the Company engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve the Company's load obligations and the use of these resources to capture available economic value. The Company transacts in wholesale markets by selling and purchasing electric capacity and energy, fuel for electric generation, and derivative contracts related to capacity, energy and fuel. Such transactions are part of the process of matching resources with load obligations and hedging the related financial risks. These transactions range from terms of intra-hour up to multiple years.

Avista Utilities makes continuing projections of:

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

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

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

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

As part of its resource procurement and management of its natural gas business, Avista Utilities makes continuing projections of its natural gas loads and assesses available natural gas resources including natural gas storage availability. Natural gas resource planning typically includes peak requirements, low and average monthly requirements and delivery constraints from natural gas supply locations to Avista Utilities' distribution system. However, daily variations in natural gas demand can be significantly different than monthly demand projections. On the basis of these projections, Avista Utilities plans and executes a series of transactions to hedge a significant portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as four natural gas operating years (November through October) into the future. Avista Utilities also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets.

Natural gas resource optimization activities include:

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

The following table presents the underlying energy commodity derivative volumes as of September 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	237	720	12,660	39,325	138	885	1,496	24,288
2015	508	2,436	13,413	115,860	254	2,935	1,490	89,925
2016	397	948	2,505	63,173	287	1,634	910	52,713
2017	397	—	675	2,895	286	—	—	2,895
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 September 30, 2014 and December 31, 2013 (dollars in thousands):

	September 30, 2014	December 31, 2013
Number of contracts	23	23
Notional amount (in United States dollars)	$ 15,734	$ 8,631
Notional amount (in Canadian dollars)	17,326	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 manage 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 September 30, 2014 and December 31, 2013 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
September 30, 2014	2	$ 50,000	2014
	5	75,000	2015
	5	95,000	2016
	3	45,000	2017
	7	155,000	2018
December 31, 2013	2	50,000	2014
	2	45,000	2015
	2	40,000	2016
	1	15,000	2017
	4	95,000	2018

In October 2014, the Company cash settled two interest rate swap contracts (notional aggregate amount of $50.0 million) and received a total of $5.4 million. The interest rate swap contracts were settled in connection with the pricing of $60.0 million of Avista Corp. first mortgage bonds that are expected to be issued in December 2014 (see Note 9). Upon settlement of interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the term of the associated debt.

In anticipation of issuing long-term debt in 2018, the Company entered into two interest rate swap agreements in October 2014, with a total aggregate notional amount of $50.0 million and a mandatory cash settlement date of June 2018. Including the October 2014 interest rate swap agreements, the Company has a total of nine interest rate swap agreements with an aggregate notional amount of $205.0 million related to the anticipated long-term debt issuance in 2018.

Derivative Instruments Summary

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of September 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 liabilities	$ —	$ (280)	$ —	$ (280)
Interest rate contracts	Other current assets	7,106	—	—	7,106
Interest rate contracts	Other property and investments - net	4,933	(3,786)	—	1,147
Interest rate contracts	Other non-current liabilities and deferred credits	1,261	(30,699)	12,730	(16,708)
Commodity contracts (1)	Current utility energy commodity derivative assets	11,371	(8,037)	—	3,334
Commodity contracts (1)	Non-current utility energy commodity derivative assets	10,639	(8,946)	—	1,693
Commodity contracts (1)	Current utility energy commodity derivative liabilities	21,002	(26,060)	49	(5,009)
Commodity contracts (1)	Other non-current liabilities and deferred credits	10,537	(25,383)	886	(13,960)
Total derivative instruments recorded on the balance sheet		$ 66,849	$ (103,191)	$ 13,665	$ (22,677)

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 September 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 September 30, 2014, the Company had deposited cash in the amount of $7.4 million and letters of credit of $38.5 million as collateral for certain energy derivative contracts. The Company also had deposited cash in the amount of $12.7 million as collateral for its interest rate swap derivative contracts. The Condensed Consolidated Balance Sheet at September 30, 2014 reflects the offsetting of $13.7 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 September 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 September 30, 2014 was $4.3 million. If the credit-risk-related contingent features underlying these agreements were triggered on September 30, 2014, the Company could be required to post $5.9 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 AEL&P. Most other subsidiary employees have salary deferral 401(k) savings plans that are defined contribution plans and these have historically not been significant to the Company.

Avista Utilities

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 $32.0 million in cash to the pension plan for the nine months ended September 30, 2014 and does not expect to contribute anything further 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 non-union employees hired or rehired by the Company on or after January 1, 2014. Actively employed non-union employees that were hired prior to January 1, 2014 and who were at that date 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 changes above, the Company revised the lump sum calculation for non-union participants who retire under the defined benefit pension plan on or after January 1, 2014 to provide retiring employees the election of 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 (IBEW) 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 Code Section 415 and the deferral of salary under deferred compensation plans. The liability and expense for this plan are included as pension benefits in the tables included in this Note.

The Company provides certain health care and life insurance benefits for eligible retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. In October 2013, the Company revised the health care benefit plan such that beginning on January 1, 2020, the methods for calculating health insurance premiums for non-union retirees under age 65 and active Company employees were revised to establish separate health insurance premiums 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 contribute towards their medical premiums and each employee would pay the full cost of premiums upon retirement. In April 2014, the local union in Oregon for the IBEW 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 nine months ended September 30 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2014	2013	2014	2013
Three months ended September 30:				
Service cost	$ 3,868	$ 4,743	$ 499	$ 971
Interest cost	6,706	5,978	1,353	1,373
Expected return on plan assets	(8,110)	(6,900)	(472)	(402)
Amortization of prior service cost	6	75	(43)	(37)
Net loss recognition	1,163	3,220	826	1,395
Net periodic benefit cost	$ 3,633	$ 7,116	$ 2,163	$ 3,300
Nine months ended September 30:				
Service cost	$ 12,754	$ 14,229	$ 1,972	$ 3,035
Interest cost	20,118	17,934	4,059	4,153
Expected return on plan assets	(24,330)	(20,700)	(1,416)	(1,202)
Amortization of prior service cost	18	225	(129)	(111)
Net loss recognition	2,334	9,989	2,001	4,342
Net periodic benefit cost	$ 10,894	$ 21,677	$ 6,487	$ 10,217

AEL&P

Union Employees

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

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

Non-Union Employees

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

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

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

NOTE 8. COMMITTED LINES OF CREDIT

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. 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, 1) there are no default events prior to the requested extension, and 2) the remaining term of agreement, including the requested extension period, does not exceed five years. 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 September 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 September 30, 2014 and December 31, 2013 (dollars in thousands):

	September 30, 2014	December 31, 2013
Borrowings outstanding at end of period	$ 35,000	$ 171,000
Letters of credit outstanding at end of period	$ 45,614	$ 27,434
Average interest rate on borrowings at end of period	0.92%	1.02%

As of September 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.

AEL&P

AEL&P has a committed line of credit in the amount of $14.5 million with an expiration date of June 2015. As of September 30, 2014, there were no borrowings outstanding under this committed line of credit. Under the terms of the agreement, interest on outstanding borrowings accrues at 0.25 percent below the prime rate with a floor of 4 percent. In addition, a fee of 0.45 percent accrues on the unadvanced portion of the 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 September 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 September 30, 2014 and December 31, 2013 (dollars in thousands):

Maturity Year	Description	Interest Rate	September 30, 2014	December 31, 2013
Avista Corp. Secured Long-Term Debt				
2016	First Mortgage Bonds	0.84%	$ 90,000	$ 90,000
2018	First Mortgage Bonds	5.95%	250,000	250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2020	First Mortgage Bonds	3.89%	52,000	52,000
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (1)	(1)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2047	First Mortgage Bonds	4.23%	80,000	80,000
	Total Avista Corp. secured long-term debt		1,376,700	1,376,700
Alaska Electric Light and Power Company Secured Long-Term Debt				
2044	First Mortgage Bonds (2)	4.54%	75,000	—
	Total consolidated secured long-term debt		1,451,700	1,376,700
	Other long-term debt and capital leases		74,754	4,630
	Settled interest rate swaps (3)		(23,118)	(23,560)
	Unamortized debt discount		(954)	(1,287)
	Total		1,502,382	1,356,483
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Current portion of long-term debt and capital leases		(6,471)	(358)
	Total long-term debt and capital leases		$ 1,412,211	$ 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) In September 2014, AEL&P issued $75.0 million of 4.54 percent first mortgage bonds due in 2044 to two institutional investors in the private placement market. The first mortgage bonds were issued under and in accordance with the AEL&P Mortgage and Deed of Trust, dated as of July 1, 2014.

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

In October 2014, the Company entered into a bond purchase agreement with three institutional investors in the private placement market for the issuance and sale of $60.0 million of Avista Corp. first mortgage bonds that are expected to be issued in December 2014. The first mortgage bonds will bear an interest rate of 4.11 percent and mature in December 2044. In connection with this pricing, the Company cash settled two interest rate swap contracts (notional aggregate amount of $50.0 million) and received a total of $5.4 million. Upon settlement of interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the term of the associated debt.

Snettisham Capital Lease Obligation

Included in long-term capital leases above is a power purchase agreement between AEL&P and AIDEA, an agency of the State of Alaska, under which AEL&P has a take-or-pay obligation, expiring in December 2038, to purchase all the output of the 78 MW Snettisham hydroelectric project. AIDEA issued $100.0 million in revenue bonds to finance its acquisition of the project and the payments by AEL&P are designed to be more than sufficient to enable the AIDEA to pay the principal and interest amount of its revenue bonds, bearing interest at rates ranging from 4.9 percent to 6.0 percent and maturing in January 2034. AEL&P will make its last bond payment to AIDEA in December 2033. The payments by AEL&P under the agreement are unconditional, notwithstanding any suspension, reduction or curtailment of the operation of the project. The bonds are payable solely out of AIDEA's receipts under the agreement. AEL&P is also obligated to operate, maintain and insure the project. AEL&P's payments for power under the agreement are approximately $10.6 million per year, while debt service on the bonds is approximately $5.9 million per year, which are included in the $10.6 million total costs of power. For accounting purposes, this power purchase agreement is treated as a capital lease.

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

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

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

As of September 30, 2014, the capital lease obligation was $70.5 million and the capital lease asset was $71.0 million (included in utility plant in service on the Condensed Consolidated Balance Sheet) and accumulated amortization was $0.9 million. For the three months ended September 30, 2014 interest on the capital lease obligation was $1.0 million and amortization of the capital lease asset was $0.9 million. These amounts were included in utility resource costs in the Condensed Consolidated Statements of Income.

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

	2014	2015	2016	2017	2018	Thereafter	Total
Principal	$ 526	$ 2,230	$ 2,350	$ 2,480	$ 2,615	$ 60,280	$ 70,481
Interest	954	3,690	3,567	3,438	3,305	28,529	43,483
Total	$ 1,480	$ 5,920	$ 5,917	$ 5,918	$ 5,920	$ 88,809	$ 113,964

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 September 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 and material capital leases), nonrecourse long-term debt and long-term debt to affiliated trusts are reported at carrying value on the Condensed Consolidated Balance Sheets.

The fair value hierarchy prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement).

The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

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

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

The following table sets forth the carrying value and estimated fair value of the Company's financial instruments not reported at estimated fair value on the Condensed Consolidated Balance Sheets as of September 30, 2014 and December 31, 2013 (dollars in thousands):

	September 30, 2014		December 31, 2013	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 951,000	$ 1,100,345	$ 951,000	$ 1,054,512
Long-term debt (Level 3)	417,000	431,758	342,000	329,581
Snettisham capital lease obligation (Level 3)	70,481	77,835	—	—
Nonrecourse long-term debt (Level 3)	5,666	5,756	17,838	18,636
Long-term debt to affiliated trusts (Level 3)	51,547	38,583	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) and the unique nature of the Snettisham capital lease obligation, the estimated fair value of these items was determined based on a discounted cash flow model using available market information.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Condensed Consolidated Balance Sheets as of September 30, 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
September 30, 2014					
Assets:					
Energy commodity derivatives	$ —	$ 52,691	$ —	$ (47,664)	$ 5,027
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	58	(58)	—
Power exchange agreement	—	—	800	(800)	—
Interest rate swaps	—	13,300	—	(5,047)	8,253
Funds held in trust account of Spokane Energy	1,600	—	—	—	1,600
Deferred compensation assets:					
Fixed income securities (2)	1,831	—	—	—	1,831
Equity securities (2)	6,096	—	—	—	6,096
Total	$ 9,527	$ 65,991	$ 858	$ (53,569)	$ 22,807
Liabilities:					
Energy commodity derivatives	$ —	$ 52,881	$ —	$ (48,599)	$ 4,282
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	1,529	(58)	1,471
Power exchange agreement	—	—	13,654	(800)	12,854
Power option agreement	—	—	362	—	362
Foreign currency derivatives	—	280	—	—	280
Interest rate swaps	—	34,485	—	(17,777)	16,708
Total	$ —	$ 87,646	$ 15,545	$ (67,234)	$ 35,957

	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 $1.0 million as of September 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, and 3) volatility rates for periods beyond October 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 September 30, 2014 (dollars in thousands):

	Fair Value (Net) at September 30, 2014	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (12,854)	Surrogate facility pricing	O&M charges	$30.66-$55.56/MWh (1)
			Escalation factor	3% - 2014 to 2019
			Transaction volumes	310,103 - 397,116 MWhs
Power option agreement	(362)	Black-Scholes-Merton	Strike price	$56.20/MWh - 2015
				$67.81/MWh - 2019
			Delivery volumes	32,472 - 287,147 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreement	(1,471)	Internally derived weighted average cost of gas	Forward purchase prices	$3.43 - $3.68/mmBTU
			Forward sales prices	$4.19 - $4.72/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 2014 were $42.90 per MWh. For ratemaking purposes the average O&M charges to be included for recovery in retail rates vary slightly between regulatory jurisdictions. The average O&M charges for the delivery year beginning in 2014 were $43.11 for Washington and $42.90 for Idaho.

(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.30 for 2014 to 0.19 in October 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 nine months ended September 30 (dollars in thousands):

	Natural Gas Exchange Agreement	Power Exchange Agreement	Power Option Agreement	Total
Three months ended September 30, 2014:				
Balance as of July 1, 2014	$ (2,183)	$ (7,919)	$ (605)	$ (10,707)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	712	(4,935)	243	(3,980)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	—	—	—	—
Transfers to/from other categories	—	—	—	—
Ending balance as of September 30, 2014	$ (1,471)	$ (12,854)	$ (362)	$ (14,687)
Three months ended September 30, 2013:				
Balance as of July 1, 2013	$ (1,022)	$ (22,179)	$ (596)	$ (23,797)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	(170)	6,135	(165)	5,800
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(1)	—	—	(1)
Transfers to/from other categories	—	—	—	—
Ending balance as of September 30, 2013	$ (1,193)	$ (16,044)	$ (761)	$ (17,998)
Nine months ended September 30, 2014:				
Balance as of January 1, 2014	$ (1,219)	$ (14,441)	$ (775)	$ (16,435)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	2,796	2,120	413	5,329
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(3,048)	(533)	—	(3,581)
Transfers to/from other categories	—	—	—	—
Ending balance as of September 30, 2014	$ (1,471)	$ (12,854)	$ (362)	$ (14,687)

		Natural Gas Exchange Agreement		Power Exchange Agreement		Power Option Agreement		Total
Nine months ended September 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)		1,637		(113)		719		2,243
Purchases		—		—		—		—
Issuance		—		—		—		—
Settlements		(451)		2,761		—		2,310
Transfers from other categories		—		—		—		—
Ending balance as of September 30, 2013	$	(1,193)	$	(16,044)	$	(761)	$	(17,998)

(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 nine months ended September 30 (in thousands, except per share amounts):

	Three months ended September 30,				Nine months ended September 30,			
	2014		2013		2014		2013	
Numerator:								
Net income from continuing operations attributable to Avista Corp. shareholders	$	10,506	$	8,450	$	89,236	$	73,882
Net income (loss) from discontinued operations attributable to Avista Corp. shareholders		(55)		2,963		70,585		5,529
Subsidiary earnings adjustment for dilutive securities (discontinued operations)		—		(81)		5		(163)
Adjusted net income (loss) from discontinued operations attributable to Avista Corp. shareholders for computation of diluted earnings per common share	$	(55)	$	2,882	$	70,590	$	5,366
Denominator:								
Weighted-average number of common shares outstanding-basic		63,934		59,994		61,413		59,933
Effect of dilutive securities:								
Performance and restricted stock awards		310		38		212		31
Weighted-average number of common shares outstanding-diluted		64,244		60,032		61,625		59,964
Earnings per common share attributable to Avista Corp. shareholders, basic:								
Earnings per common share from continuing operations	$	0.16	$	0.14	$	1.45	$	1.23
Earnings per common share from discontinued operations	$	—	$	0.05	$	1.15	$	0.09
Total earnings per common share attributable to Avista Corp. shareholders, basic	$	0.16	$	0.19	$	2.60	$	1.32
Earnings per common share attributable to Avista Corp. shareholders, diluted:								
Earnings per common share from continuing operations	$	0.16	$	0.14	$	1.45	$	1.23
Earnings per common share from discontinued operations	$	—	$	0.05	$	1.14	$	0.09
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$	0.16	$	0.19	$	2.59	$	1.32

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' or AEL&P's 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 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' filed Objections to Findings and Recommendations of Magistrate Judge and the Colstrip Owners filed their response to Plaintiffs' objections.

On August 27, 2014, the Plaintiffs filed a Second Amended Complaint. The Second Amended Complaint withdraws from the Amended Complaint five claims and adds one new claim. The Second Amended Complaint alleges certain violations of the Clean Air Act and the New Source Review. The Plaintiffs request that the Court grant injunctive and declaratory relief, order remediation of alleged environmental damages, impose civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require payment of Plaintiffs’ costs of litigation and attorney fees.

The Court has set the trial date for August 2015.

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

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. The Company obtained regulatory Orders from the UTC and IPUC during the second half of 2013, allowing regulatory treatment of the costs from the discontinued project.

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 September 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 agreements with the International Brotherhood of Electrical Workers represent approximately 45 percent of all of Avista Utilities’ employees. The agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the Avista Utilities' bargaining unit employees expired in March 2014. A new 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.

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

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; therefore, it is considered one segment. Ecova was a provider of facility information and cost management services for multi-site customers throughout North America. The Ecova business segment 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, the Company completed its acquisition of AERC. Based on the way AERC is managed and the financial reports that are reviewed by the Chief Operating Decision Maker, AEL&P, the primary subsidiary of AERC is considered a separate reportable business segment and the remaining activities of AERC are included in the Other category. All goodwill associated with the AERC acquisition has been assigned to the AEL&P reportable business segment.

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

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the three months ended September 30, 2014:						
Operating revenues	$ 282,555	$ 9,157	$ 291,712	$ 10,296	$ (450)	$ 301,558
Resource costs	128,591	2,997	131,588	—	—	131,588
Other operating expenses	69,403	3,106	72,509	10,701	(450)	82,760
Depreciation and amortization	32,006	1,288	33,294	154	—	33,448
Income (loss) from operations	32,048	1,273	33,321	(559)	—	32,762
Interest expense (2)	18,247	485	18,732	186	(163)	18,755
Income taxes	7,146	329	7,475	(174)	—	7,301
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	10,349	511	10,860	(354)	—	10,506
Capital expenditures (3)	92,197	1,053	93,250	194	—	93,444
For the three months ended September 30, 2013:						
Operating revenues	$ 278,923	$ —	$ 278,923	$ 11,004	$ (450)	$ 289,477
Resource costs	131,136	—	131,136	—	—	131,136
Other operating expenses	69,596	—	69,596	10,662	(450)	79,808
Depreciation and amortization	29,823	—	29,823	171	—	29,994
Income from operations	29,657	—	29,657	170	—	29,827
Interest expense (2)	18,837	—	18,837	525	(77)	19,285
Income taxes	3,945	—	3,945	(578)	—	3,367
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	9,447	—	9,447	(1,074)	77	8,450
Capital expenditures (3)	75,368	—	75,368	24	—	75,392
For the nine months ended September 30, 2014:						
Operating revenues	$ 1,023,684	$ 9,157	$ 1,032,841	$ 29,225	$ (1,350)	$ 1,060,716
Resource costs	478,010	2,997	481,007	—	—	481,007
Other operating expenses	204,089	3,106	207,195	21,864	(1,350)	227,709
Depreciation and amortization	93,912	1,288	95,200	452	—	95,652
Income from operations	177,653	1,273	178,926	6,909	—	185,835
Interest expense (2)	55,215	485	55,700	899	(330)	56,269
Income taxes	48,068	329	48,397	2,877	—	51,274
Net income from continuing operations attributable to Avista Corp. shareholders	85,030	511	85,541	3,528	167	89,236
Capital expenditures (3)	228,711	1,053	229,764	296	—	230,060

	Avista Utilities		Alaska Electric Light and Power Company		Total Utility		Other		Intersegment Eliminations (1)		Total
For the nine months ended September 30, 2013:											
Operating revenues	$	1,008,669	$	—	$	1,008,669	$	30,145	$	(1,350)	$	1,037,464
Resource costs		487,277		—		487,277		—		—		487,277
Other operating expenses		200,824		—		200,824		30,322		(1,350)		229,796
Depreciation and amortization		86,783		—		86,783		536		—		87,319
Income (loss) from operations		167,648		—		167,648		(713)		—		166,935
Interest expense (2)		56,635		—		56,635		1,801		(230)		58,206
Income taxes		43,278		—		43,278		(1,349)		—		41,929
Net income (loss) from continuing operations attributable to Avista Corp. shareholders		76,265		—		76,265		(2,613)		230		73,882
Capital expenditures (3)		220,712		—		220,712		139		—		220,851
Total Assets:												
As of September 30, 2014:	$	3,991,330	$	261,402	$	4,252,732	$	83,614	$	—	$	4,336,346
As of December 31, 2013 (4):	$	3,940,998	$	—	$	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 September 30, 2014, and the related condensed consolidated statements of income and comprehensive income for the three-month and nine-month periods ended September 30, 2014 and 2013, and the related condensed consolidated statements of equity and redeemable noncontrolling interests and cash flows for the nine-month periods ended September 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
November 5, 2014

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

Business Segments

As of September 30, 2014, we have two reportable business segments as follows:

- **Avista Utilities** – an operating division of Avista Corp. that comprises our regulated utility operations in the Pacific Northwest. 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. We also supply electricity to a small number of customers in Montana, most of whom are employees who operate our Noxon Rapids generating facility. Avista Utilities also engages in wholesale purchases and sales of electricity and natural gas.
- **Alaska Electric Light and Power Company** - the primary operating subsidiary of AERC, which provides electric services in the City and Borough of Juneau, Alaska. We completed our acquisition of AERC on July 1, 2014, and as of that date, AERC is a wholly-owned subsidiary of Avista Corp.

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

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Avista Utilities	$ 10,349	$ 9,447	$ 85,030	$ 76,265
Alaska Electric Light and Power Company	511	—	511	—
Ecova - Discontinued operations (1)	(55)	3,040	70,752	5,759
Other	(354)	(1,074)	3,528	(2,613)
Net income attributable to Avista Corporation shareholders	$ 10,451	$ 11,413	$ 159,821	$ 79,411

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

Executive Level Summary

Overall Results

Net income attributable to Avista Corporation shareholders was $10.5 million for the three months ended September 30, 2014, a decrease from $11.4 million for the three months ended September 30, 2013. For the nine months ended September 30, 2014, net income attributable to Avista Corporation shareholders was $159.8 million, an increase from $79.4 million for the nine months ended September 30, 2013. The decrease in quarter-to-date earnings was primarily due to the disposition of Ecova on June 30, 2014, partially offset by earnings at AEL&P. We also had increased earnings at Avista Utilities primarily due to the implementation of general rate increases in each of our jurisdictions and lower net power supply costs, partially offset by the provision for earnings sharing in Idaho, and expected increases in depreciation and amortization, and taxes other than income taxes, as well as an increase in income tax expense.

The increase in year-to-date earnings was primarily due to the disposition of Ecova, which resulted in the recognition of a $68.0 million net gain. In addition, we recognized a $9.8 million net gain during the second quarter related to the settlement of the California power markets litigation involving Avista Energy. 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 each of our jurisdictions and lower net power supply costs, partially offset by the provision for earnings sharing in Idaho. Our utility earnings benefited from colder weather during the first quarter, which was partially offset by milder weather in the second quarter and weather that was cooler than the prior year in the third quarter. There were also 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 (GRC)

In our utility operations (both Avista Utilities and AEL&P), we regularly review the need for rate changes in each jurisdiction to improve the recovery of costs and capital investments in our generation, transmission and distribution systems. The following are the recent general rate increases that have occurred or could possibly go into effect in the near future:

Jurisdiction	Service	Effective Date	Original GRC Filing Date	Commission Approval Date
Washington	Electric and Natural Gas	January 1, 2013	April 2012	December 2012
	Electric and Natural Gas	January 1, 2014	April 2012	December 2012
	Electric and Natural Gas	January 1, 2015	February 2014	Pending (1)
Idaho	Natural Gas	April 1, 2013	October 2012	March 2013
	Electric and Natural Gas	October 1, 2013	October 2012	March 2013
	Electric and Natural Gas	January 1, 2015	July 2014	September 2014 (2)
Oregon	Natural Gas	February 1, 2014	August 2013	January 2014
	Natural Gas	November 1, 2014	August 2013	January 2014
	Natural Gas	July 2015	September 2014	Pending (3)

(1) On August 18, 2014, we filed an all-party settlement agreement with the UTC related to our electric and natural gas general rate cases, which were originally filed in February 2014. The settlement is designed to increase annual electric base revenues by 1.4 percent or $7.0 million and annual natural gas base revenues by 5.6 percent or $8.5 million. We expect the UTC to issue an Order regarding the settlement before the end of 2014. See further discussion below under "Washington General Rate Cases."

(2) In September 2014, the IPUC approved our 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 approved extension, base retail rates will remain unchanged through December 31, 2015. See further discussion below under "Idaho General Rate Cases."

(3) On September 2, 2014, we filed a general rate case with the OPUC requesting an overall increase in base natural gas rates of 9.3 percent (designed to increase annual natural gas revenues by $9.1 million). The OPUC has up to 10 months to review the case and make a decision. If approved, new rates would take effect no later than July 2015. See further discussion below under "Oregon General Rate Case."

In addition to the above, AEL&P, based in Juneau, Alaska (discussed below) is evaluating the need to file an electric general rate case with the RCA. We don't have plans to file an electric general rate case in 2014. AEL&P's last general rate case was filed in 2010 and approved by the RCA in 2011.

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 $228.7 million for the nine months ended September 30, 2014. We expect Avista Utilities' capital expenditures to be about $355.0 million in 2014, $355.0 million in 2015 and $350.0 million in 2016. AEL&P's capital expenditures were $1.1 million for the three months ended September 30, 2014. We expect to spend approximately $3.0 million for 2014 (from July 1 through the end of the year) and $15.0 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 $109.0 million. For the first nine months of 2014, AERC had revenues of $35.3 million, $9.2 million of which were recognized by Avista Corp. in the third quarter. AEL&P 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. AEL&P 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 this acquisition, we issued 4,500,014 new shares of common stock to the shareholders of AERC based on a contractual price formula which was $32.46 per share and we made $4.7 million in cash payments. The consideration exchanged reflects a purchase of $170.0 million, plus acquired cash, less outstanding debt and other closing adjustments.

This transaction resulted in the recording of $50.6 million in goodwill during the third quarter of 2014.

In AEL&P's most recent general rate case in 2010, 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.

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.

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 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 $68.0 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 a program to repurchase up to 4 million shares of the Company’s outstanding common stock, assuming the closure of the Ecova transaction. Repurchases of common stock under this program commenced on July 7, 2014 and the program expires on December 31, 2014. We can 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 October 31, 2014, we repurchased

2,529,615 shares at a total cost of $79.9 million and an average cost of $31.57 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. The remainder of the proceeds were used to fund current operations and decrease reliance on short-term 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 above).

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, 1) there are no default events prior to the requested extension, and 2) the remaining term of agreement, including the requested extension period, does not exceed five years. The amendment did not change the amount of the committed line of credit. As of September 30, 2014, there were $35.0 million of cash borrowings and $45.6 million in letters of credit outstanding leaving $319.4 million of available liquidity under this line of credit.

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

In September 2014, AEL&P issued $75.0 million of 4.54 percent first mortgage bonds due in 2044 to two institutional investors in the private placement market. We acquired AERC primarily by issuing Avista Corp. common stock. The proceeds from the AEL&P bonds were used to repay approximately $38.0 million of existing AEL&P debt, with the remainder of the proceeds and cash on-hand being paid as a cash dividend of $50.0 million to Avista Corp. associated with rebalancing the consolidated capital structure at AERC. In addition to the first mortgage bonds, we expect to issue $15.0 million in term loans at AERC during the fourth quarter of 2014.

In October 2014, we entered into a bond purchase agreement with three institutional investors in a private placement transaction for the issuance and sale of $60.0 million of Avista Corp. first mortgage bonds that are expected to be issued in December 2014. The first mortgage bonds will bear an interest rate of 4.11 percent and mature in December 2044.

In the nine months ended September 30, 2014, we issued $153.5 million (net of issuance costs) of common stock which includes $150.1 million associated with the acquisition of AERC and the remainder under the dividend reinvestment and direct stock purchase plan, and employee plans. 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 expect to issue any additional shares in 2014, other than small amounts 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. This program expires on December 31, 2014 and we have the option to terminate the program before that date.

For 2015, we expect to issue approximately $100.0 million of long-term debt and approximately $30.0 million of common stock in order to maintain an appropriate capital structure.

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 to Avista Energy from the litigation settlement and proceeds from the Ecova disposition, we expect net cash flows from operating activities, together with cash available under our $400.0 million committed line of credit agreement and the $14.5 million AEL&P committed line of credit, to provide adequate resources to fund capital expenditures, dividends, and other contractual commitments.

Regulatory Matters

General Rate Cases

We regularly review the need for electric and natural gas rate changes in each state in which we provide service. We will continue to file for rate adjustments to:

- seek recovery of operating costs and capital investments, and
- seek the opportunity to earn reasonable returns as allowed by regulators.

With regards to the timing and plans for future filings, the assessment of our need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include, but are not limited to, in-service dates of major capital investments and the timing of changes in major revenue and expense items.

Washington General Rate Cases

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 provided 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 does not impact our earnings. The ERM balance as of September 30, 2014 was a liability of $15.8 million.

The settlement agreement provided 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 had 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 was 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 $355.0 million in 2014, and $355.0 million in 2015, which are above the capital expenditures contemplated in the settlement agreement.

2014 General Rate Cases

On August 18, 2014, we filed an all-party settlement agreement with the UTC related to our electric and natural gas general rate cases filed on February 4, 2014. If approved by the UTC, the settlement would conclude these general rate requests and new rates would take effect on January 1, 2015. The settlement is designed to increase annual electric base revenues by $7.0 million, or 1.4 percent, and annual natural gas base revenues by $8.5 million, or 5.6 percent. The electric base revenue increase of $7.0 million will increase or decrease with the November 2014 power supply update explained below. The estimate of the power supply update is an additional base revenue increase of $6.3 million. We expect the UTC to issue an Order regarding the settlement before the end of 2014.

Expiring and New Rebates and Energy Recovery Mechanism (ERM)

The parties agreed in the settlement that a credit of $3.0 million from the existing ERM deferral balance would be returned to electric customers to help offset the 2015 rate increase, which would reduce the overall electric billed rate increase from 1.4 percent to 0.8 percent. This ERM balance represents lower power supply costs in recent years than the costs embedded in base retail rates, which are being returned to customers in the form of a rebate. This rebate will not increase or decrease our net income. Total net deferred power costs under the ERM were a liability of $15.8 million as of September 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.

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

The overall change in customer billing rates from the settlement agreement, including the expiring and new rebates, is 2.4 percent for electric customers and 5.5 percent for natural gas customers.

The revised customer billings also include a proposed increase in the monthly basic charge from $8.00 to $8.50 for electric customers, and a proposed increase in the monthly basic charge from $8.00 to $9.00 for natural gas customers. The monthly basic charge increases are designed to increase electric revenues by $2.4 million or 0.5 percent and natural gas revenues by $1.9 million or 1.2 percent. The $2.4 million and $1.9 million increases for electric and natural gas revenues, respectively are included in the $7.0 million and $8.5 million overall increases disclosed above for electric and natural gas revenues, respectively.

Power Supply Update and Customer Information and Work Management Systems Deferral

The proposed settlement agreement includes a provision that requires us to rerun power supply costs on November 1, 2014 to be filed with the UTC on or before November 17, 2014. This update to power supply costs would be reflected in the overall electric revenue increase effective January 1, 2015, and would reset the base power supply costs for the ERM tracker calculations effective January 1, 2015. The estimate for the update is a $6.3 million increase in power supply costs. If the power supply update results in an increase in net power supply costs, the increase to customers would be offset with the available ERM deferral balance for the calendar year 2015. The use of the ERM deferral balance for the offset would not increase or decrease our net income.

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

Decoupling

The parties agreed that we would implement electric and natural gas decoupling mechanisms for a five-year period beginning January 1, 2015. Decoupling is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. Our actual revenue, based on kilowatt hour and therm sales will vary, up or down, from the level established by the UTC in a general rate case. This could be due to changes in weather, conservation or the economy. Per the terms of the settlement agreement and the proposed decoupling mechanisms included therein, generally, our electric and natural gas revenues will be based on the number of customers, rather than kilowatt hour and therm sales. The difference between revenues based on sales and revenues based on the number of customers will be deferred and either surcharged or rebated to customers beginning in the following year. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to 3 percent on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

The decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations will be made for the prior calendar year. These earnings tests will reflect actual decoupled revenues, normalized power supply costs, and other normalizing adjustments.

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

Original Request

Our original request filed with the Commission in February 2014 included a base electric rate increase of 3.8 percent (designed to increase annual electric revenues by $18.2 million). It also requested a base natural gas rate increase of 8.1 percent (designed to increase annual natural gas revenues by $12.1 million). Specific capital structure ratios and the cost of capital components were not agreed to in the settlement agreement, and the revenue increases in the settlement were not tied to the 7.32 percent ROR referenced above. The electric and natural gas revenue increases were negotiated numbers, with each party using its own set of assumptions underlying its agreement to the revenue increases. The parties agreed that the 7.32 percent ROR will be used to calculate the Allowance for Funds Used During Construction (AFUDC) and other purposes.

Idaho General Rate Cases

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 allowed 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

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

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

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

- the delay of the beginning of the amortization of the 2013 previously deferred operations and maintenance costs pertaining to the Colstrip and Coyote Springs 2 thermal generating facilities from 2015 to 2016, and
- deferred accounting, for later review and recovery, of the majority of the costs associated with Project Compass, 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 will 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 September 30, 2014, we have deferred a total of $5.3 million for the 2014 after-the-fact earnings test, which represents our estimate for the nine months ended September 30, 2014. During 2015, if we earn more than the 9.8 percent ROE, 50 percent of the earnings above 9.8 percent will be shared with customers through future ratemaking.

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

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 were implemented in two phases: February 1, 2014 and November 1, 2014. Effective February 1, 2014, rates increased for Oregon natural gas customers on a billed basis by an overall 4.4 percent (designed to increase annual revenues by $3.8 million). Effective November 1, 2014, rates for Oregon natural gas customers were to increase on a billed basis by an overall 1.6 percent (designed to increase annual revenues by $1.4 million).

The billed rate increase on November 1, 2014 was dependent upon the completion of Project Compass and the actual costs incurred through September 30, 2014, and the actual costs incurred through June 30, 2014 related to our Aldyl A distribution pipeline replacement program. As noted elsewhere, Project Compass is expected to be completed during the first half of 2015. The November 1, 2014 rate increase was reduced from $1.4 million to $0.3 million due to the delay of Project Compass.

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

2014 General Rate Case

On September 2, 2014, we filed a general rate case with the OPUC requesting an overall increase in base natural gas rates of 9.3 percent (designed to increase annual natural gas revenues by $9.1 million). This is based on a proposed rate of return of 7.77 percent with a common equity ratio of 51 percent and a 9.9 percent return on equity. In addition, we have proposed an increase in the monthly basic charge from $8.00 to $10.00. The OPUC has up to 10 months to review the case and make a decision. If approved, new rates would take effect no later than July 2015.

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 $0.7 million as of September 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 and 2014.

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

(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 $15.8 million as of September 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. The IPUC issued an Order approving the costs for the previous July-June twelve-month period during the third quarter of 2014. Total net power supply costs deferred under the PCA mechanism were an asset of $9.2 million as of September 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, AEL&P, Ecova - Discontinued Operations 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."

The balances included below for utility operations reconcile to the Condensed Consolidated Statements of Income. Beginning with the three months ended September 30, 2014, AEL&P is included in the overall utility results.

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

Utility revenues increased $12.8 million, after elimination of intracompany revenues of $40.9 million for the third quarter of 2014 and $32.1 million for the third quarter of 2013. Avista Utilities' portion of utility revenues increased $3.6 million for the third quarter of 2014 and AEL&P had electric revenues of $9.2 million. Including intracompany revenues, electric revenues at Avista Utilities decreased $7.5 million and natural gas revenues increased $19.9 million. Avista Utilities' retail electric revenues increased $1.9 million primarily due to general rate increases, partially offset by weather that, while significantly warmer than normal, was slightly cooler than the prior year. Wholesale electric revenues increased $11.1 million primarily due to an increase in sales volumes while sales of fuel decreased $18.4 million. In the third quarter of 2014, we estimated a provision for earnings sharing of $3.1 million for Idaho electric customers. Retail natural gas revenues increased $1.5 million due to higher rates (from PGAs and general rate increases), partially offset by a decrease in volumes (due to milder weather in September), while wholesale natural gas revenues increased $19.6 million due to an increase in prices and volumes. In the third quarter of 2014, we estimated a provision for earnings sharing of $0.9 million for Idaho natural gas customers.

Utility resource costs increased $0.5 million, after elimination of intracompany resource costs of $40.9 million for the third quarter of 2014 and $32.1 million for third quarter of 2013. Avista Utilities' portion of resource costs decreased $2.5 million and this was offset by utility resource costs at AEL&P of $3.0 million. Including intracompany resource costs, Avista Utilities' electric resource costs decreased $13.9 million and natural gas resource costs increased $20.1 million. The decrease in Avista Utilities' electric resource costs was primarily due to a decrease in 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), purchased power, and fuel for generation, partially offset by an increase in power cost amortizations and other regulatory amortizations. The increase in natural gas resource costs was primarily due to an increase in natural gas purchased.

Utility other operating expenses increased $2.9 million and was the result of AEL&P being included in the third quarter of 2014, which added $3.1 million to other operating expenses. Avista Utilities' other operating expenses decreased slightly due to a decrease in pension and other postretirement benefits, partially offset by increased generation maintenance and gas distribution operating and maintenance expenses. In addition, there were transaction fees associated with the AERC acquisition of $0.6 million recorded during the third quarter of 2014, compared to transaction expenses of $0.1 million during the third quarter of 2013.

Utility depreciation and amortization increased $3.5 million driven by additions to utility plant. Also, depreciation expense included $1.3 million in the current quarter related to AEL&P.

Utility taxes other than income taxes increased $2.3 million primarily due to increased production, distribution and transmission property taxes. Also, the current quarter included $0.5 million related to AEL&P.

Interest expense decreased $0.5 million primarily due to the long-term debt outstanding during the third quarter of 2014 having a lower interest rate than the long-term debt outstanding during the third quarter of 2013. This was partially offset by the acquisition of AEL&P, which added $0.5 million for the current quarter.

Income taxes increased $3.9 million and our effective tax rate was 41.0 percent for the third quarter of 2014 compared to 28.4 percent for the third quarter of 2013. The increase in expense was primarily due to an increase in income before income taxes. The increase in the effective tax rate was primarily the result of a tax provision to tax return true-up related to the 2013 tax return and an adjustment related to the deduction for our pension funding. This was offset by a Section 199 deduction recorded during the third quarter.

Nine months ended September 30, 2014 compared to the nine months ended September 30, 2013

Utility revenues increased $24.2 million, after elimination of intracompany revenues of $104.2 million for the nine months ended September 30, 2014 and $105.5 million for the nine months ended September 30, 2013. Avista Utilities' portion of utility revenues increased $15.0 million for the nine months ended September 30, 2014 and AEL&P had electric revenues of $9.2 million, representing their revenues for the three months ended September 30, 2014. Including intracompany revenues, Avista Utilities' electric revenues decreased $33.3 million and natural gas revenues increased $47.0 million. Avista Utilities' retail electric revenues increased $12.9 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 increased $7.0 million due to an increase in sales prices partially offset by a decrease in sales volumes while sales of fuel decreased $37.5 million. Other electric revenues decreased $9.5 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. In the nine months ended September 30, 2014, we estimated a provision for earnings sharing of $6.2 million for Idaho electric customers with $4.3 million representing our estimate for the nine months ended September 30, 2014 and $1.9 million representing an adjustment of our 2013 estimate. Retail natural gas revenues increased $14.6 million due to higher rates (from PGAs and general rate increases) and an increase in volumes (due to customer growth and colder weather in the first quarter), while wholesale natural gas revenues increased $33.9 million due to an increase in prices, partially offset by a decrease in volumes. In the nine months ended September 30, 2014, we estimated a provision for earnings sharing of $1.1 million for Idaho natural gas customers, with less than $0.1 million representing an adjustment of our 2013 estimate and the remainder representing our estimate for the nine months ended September 30, 2014.

Total utility resource costs decreased $6.3 million, after elimination of intracompany resource costs of $104.2 million for the first nine months of 2014 and $105.5 million for the first nine months of 2013. Avista Utilities' portion of resource costs decreased $9.3 million and this was offset by utility resource costs at AEL&P of $3.1 million, representing their resource costs for the three months ended September 30, 2014. Including intracompany resource costs, Avista Utilities' electric resource costs decreased $51.8 million and natural gas resource costs increased $41.2 million. The decrease in Avista Utilities' electric resource costs was primarily due to the Colstrip outage in 2013 and increased hydroelectric generation in 2014. Specifically, there were decreases 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 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 $6.4 million and was partially the result of AEL&P being included in the third quarter of 2014, which added $3.1 million to other operating expenses. Also, we incurred increased generation, transmission and distribution operating and maintenance expenses and increased outside services. There were also transaction fees associated with the AERC acquisition of $1.3 million in the first nine months of 2014 compared to $0.1 million for the first nine months of 2013. These were partially offset by a decrease in pension and other post-retirement benefits expense.

Utility depreciation and amortization increased $8.4 million driven by additions to utility plant. Also, the third quarter included $1.3 million related to AEL&P.

Utility taxes other than income taxes increased $4.4 million primarily due to increased production, distribution and transmission property taxes. Also, the third quarter included $0.5 million related to AEL&P.

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 $1.9 million primarily due to the long-term debt outstanding during the first nine months of 2014 having a lower interest rate than the long-term debt outstanding during the first nine months of 2013. This was partially offset by the acquisition of AEL&P, which added $0.5 million for the third quarter.

Income taxes increased $9.3 million and our effective tax rate was 36.5 percent for the first nine months of 2014 compared to 36.2 percent for the first nine months of 2013. The increase in expense was primarily due to an increase in income before income taxes.

Avista Utilities

Non-GAAP Financial Measures

The following discussion for Avista Utilities includes two financial measures that are considered “non-GAAP financial measures,” electric gross margin and natural gas gross margin. In the AEL&P section, we include a discussion of electric gross margin. Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included (excluded) in the most directly comparable measure calculated and presented in accordance with GAAP. The presentation of electric gross margin and natural gas gross margin for Avista Utilities and electric gross margin for AEL&P is intended to supplement an understanding of Avista Utilities' and AEL&P's operating performance. We use these measures to determine whether the appropriate amount of energy costs are being collected from our customers to allow for recovery of operating costs, as well as to analyze how changes in loads (due to weather, economic or other conditions), rates, supply costs and other factors impact our results of operations. These measures are not intended to replace income from operations as determined in accordance with GAAP as an indicator of operating performance. The calculations of electric and natural gas gross margins are presented below.

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

Net income for Avista Utilities was $10.3 million for the third quarter of 2014, an increase from $9.4 million for the third quarter of 2013. Avista Utilities’ income from operations was $32.0 million for the third quarter of 2014, an increase from $29.7 million for the third quarter of 2013. The increase in income from operations was primarily due to an increase in gross margin and a slight decrease in other operating expenses, partially offset by expected increases in depreciation and amortization, and taxes other than income taxes.

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

	Electric		Natural Gas		Intracompany		Total	
	2014	2013	2014	2013	2014	2013	2014	2013
Operating revenues	$ 232,819	$ 240,317	$ 90,604	$ 70,745	$ (40,868)	$ (32,139)	$ 282,555	$ 278,923
Resource costs	97,000	110,900	72,459	52,375	(40,868)	(32,139)	128,591	131,136
Gross margin	$ 135,819	$ 129,417	$ 18,145	$ 18,370	$ —	$ —	$ 153,964	$ 147,787

Avista Utilities' operating revenues increased $3.6 million and resource costs decreased $2.6 million, which resulted in an increase of $6.2 million in gross margin. The gross margin on electric sales increased $6.4 million and the gross margin on natural gas sales decreased $0.2 million. The increase in electric gross margin was primarily due to general rate increases in Washington and Idaho and lower power supply costs, partially offset by a $3.1 million provision for earnings sharing in Idaho and weather that was cooler than the prior year (although warmer than normal), which decreased cooling loads. For the third quarter of 2014, we recognized a pre-tax benefit of $0.4 million under the ERM in Washington compared to an expense of $4.7 million for the third quarter of 2013. This change represents a decrease in net power supply costs primarily due to the Colstrip outage in 2013 and partially due to increased hydroelectric generation in 2014. The decrease in natural gas gross margin was primarily due to a $0.9 million provision for earnings sharing in Idaho, partially offset by general rate increases.

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 September 30 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2014	2013	2014	2013
Residential	$ 73,940	$ 73,800	808	839
Commercial	78,323	77,776	841	854
Industrial	28,852	27,645	485	465
Public street and highway lighting	1,877	1,857	6	6
Total retail	182,992	181,078	2,140	2,164
Wholesale	35,209	24,104	915	623
Sales of fuel	10,647	29,088	—	—
Other	7,051	6,047	—	—
Provision for earnings sharing	(3,080)	—	—	—
Total	$ 232,819	$ 240,317	3,055	2,787

Retail electric revenues increased $1.9 million due to an increase in revenue per MWh (increased revenues $3.9 million), partially offset by a decrease in total MWhs sold (decreased revenues $2.0 million). The increase in revenue per MWh was primarily due to general rate increases.

The decrease in total MWhs sold to residential customers was primarily the result of weather that, while significantly warmer than normal, was slightly cooler than the prior year. Compared to the third quarter of 2013, residential electric use per customer decreased 5 percent and commercial use per customer decreased 4 percent. Cooling degree days at Spokane were 83 percent above average, but 3 percent below the third quarter of 2013.

Wholesale electric revenues increased $11.1 million due to an increase in sales volumes (increased revenues $11.2 million), partially offset by a slight decrease in sales prices (decreased revenues $0.1 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 $18.4 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.

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 third quarter of 2014, we estimated a provision for earnings sharing of $3.1 million for Idaho electric customers.

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

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2014	2013	2014	2013
Residential	$ 18,138	$ 17,448	12,619	13,022
Commercial	10,640	10,057	11,173	11,248
Interruptible	567	547	1,066	1,250
Industrial	827	667	1,134	955
Total retail	30,172	28,719	25,992	26,475
Wholesale	58,052	38,439	151,663	115,754
Transportation	1,663	1,600	34,078	33,767
Other	1,631	1,987	22	18
Provision for earnings sharing	(914)	—	—	—
Total	$ 90,604	$ 70,745	211,755	176,014

Retail natural gas revenues increased $1.5 million due to higher retail rates (increased revenues $2.0 million), partially offset by a decrease in volumes (decreased revenues $0.5 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 third quarter of 2014 as compared to the third quarter of 2013 primarily due to milder weather in September. Compared to the third quarter of 2013, residential natural gas use per customer decreased 4 percent and commercial use per customer decreased 1 percent. Heating degree days at Spokane were 62 percent below historical average for the third quarter of 2014, and 35 percent below the third quarter of 2013. Heating degree days at Medford were 81 percent below historical average for the third quarter of 2014 and 81 percent below the third quarter of 2013. There has historically not been a significant number of heating degree days during the third quarter of each year.

Wholesale natural gas revenues increased $19.6 million due to an increase in volumes (increased revenues $13.7 million) and an increase in prices (increased revenues $5.9 million). We plan for sufficient natural gas capacity to serve our retail customers on a theoretical peak day. As such, on nonpeak days we generally have more pipeline and storage capacity than what is needed for retail loads. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that partially offsets net natural gas costs. In some situations, customer demand is below the amount hedged and we sell natural gas in excess of load requirements. In the third quarter of 2014, $25.8 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In the third quarter of 2013, $9.4 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 September 30:

	Electric Customers		Natural Gas Customers	
	2014	2013	2014	2013
Residential	323,789	320,685	290,932	287,541
Commercial	41,084	40,178	33,931	33,814
Interruptible	—	—	38	40
Industrial	1,383	1,387	269	259
Public street and highway lighting	531	528	—	—
Total retail customers	366,787	362,778	325,170	321,654

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

	2014	2013
Electric resource costs:		
Power purchased	$ 40,341	$ 40,901
Power cost amortizations, net	(3,333)	(6,751)
Fuel for generation	35,651	36,060
Other fuel costs	13,800	30,908
Other regulatory amortizations, net	5,475	5,015
Other electric resource costs	5,066	4,767
Total electric resource costs	97,000	110,900
Natural gas resource costs:		
Natural gas purchased	76,183	55,044
Natural gas cost amortizations, net	(4,225)	(3,044)
Other regulatory amortizations, net	501	375
Total natural gas resource costs	72,459	52,375
Intracompany resource costs	(40,868)	(32,139)
Total resource costs	$ 128,591	$ 131,136

Power purchased decreased $0.6 million due to a decrease in the volume of power purchases (decreased costs $3.9 million), partially offset by an increase in wholesale prices (increased costs $3.3 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 $3.3 million for the three months ended September 30, 2014 compared to $6.8 million for the three months ended September 30, 2013. During the three months ended September 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 $2.2 million through an ERM rebate. During the three months ended September 30, 2014, actual power supply costs were below the amount included in base retail rates in Washington and we deferred $1.7 million for probable future benefit to customers. We deferred $1.8 million in Idaho for probable future surcharge to customers.

Other fuel costs decreased $17.1 million. This represents fuel and the related derivative instruments that were purchased for generation but were later sold when conditions indicated that it was not economical to use the fuel for generation, as part of the resource optimization process. When the fuel or related derivative instruments are sold, that revenue is included in sales of fuel.

The expense for natural gas purchased increased $21.1 million due to an increase in total therms purchased (increased costs $15.2 million) and an increase in the price of natural gas (increased costs $5.9 million). Total therms purchased increased due to an increase in wholesale sales which are used to balance loads and resources as part of the natural gas procurement and resource optimization process, partially offset by a decrease in retail sales. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs.

Nine months ended September 30, 2014 compared to the nine months ended September 30, 2013

Net income for Avista Utilities was $85.0 million for the nine months ended September 30, 2014, an increase from $76.3 million for the nine months ended September 30, 2013. Avista Utilities' income from operations was $177.7 million for the nine months ended September 30, 2014, an increase from $167.6 million for the nine months ended September 30, 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 nine months ended September 30 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2014	2013	2014	2013	2014	2013	2014	2013
Operating revenues	$ 738,943	$ 772,252	$ 388,904	$ 341,872	$ (104,163)	$ (105,455)	$ 1,023,684	$ 1,008,669
Resource costs	302,900	354,682	279,273	238,050	(104,163)	(105,455)	478,010	487,277
Gross margin	$ 436,043	$ 417,570	$ 109,631	$ 103,822	$ —	$ —	$ 545,674	$ 521,392

Avista Utilities' operating revenues increased $15.0 million and resource costs decreased $9.3 million, which resulted in an increase of $24.3 million in gross margin. The gross margin on electric sales increased $18.5 million and the gross margin on natural gas sales increased $5.8 million. The increase in electric gross margin was primarily due to general rate increases in Washington and Idaho and lower power supply costs (due to the Colstrip outage in 2013 and increased hydroelectric generation in 2014), as well as colder weather in the first quarter. This was partially offset by cooler weather (although warmer than normal) in the third quarter and a $6.2 million provision for earnings sharing in Idaho. For the nine months ended September 30, 2014, we recognized a pre-tax benefit of $5.3 million under the ERM in Washington compared to an expense of $0.5 million for the nine months ended September 30, 2013. This change represents a decrease in net power supply costs primarily due to the Colstrip outage in 2013 and partially due to increased hydroelectric generation in 2014. Electric gross margin for 2013 included the net benefit from the settlement with the BPA of $5.1 million. The increase in natural gas gross margin was due to general rate increases. Weather was colder than average and colder than the prior year in the first quarter and this was partially offset by milder weather in the second and third quarters 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 nine months ended September 30 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2014	2013	2014	2013
Residential	$ 247,684	$ 237,088	2,701	2,695
Commercial	224,049	215,899	2,393	2,356
Industrial	82,279	88,230	1,392	1,547
Public street and highway lighting	5,660	5,534	19	19
Total retail	559,672	546,751	6,505	6,617
Wholesale	108,096	101,065	3,015	3,135
Sales of fuel	56,826	94,348	—	—
Other	20,533	30,088	—	—
Provision for earnings sharing	(6,184)	—	—	—
Total	$ 738,943	$ 772,252	9,520	9,752

Retail electric revenues increased $12.9 million due to an increase in revenue per MWh (increased revenues $22.5 million), partially offset by a decrease in total MWhs sold (decreased revenues $9.6 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 slight increase in total MWhs sold to residential and commercial customers was primarily due to customer growth. Colder weather in the first quarter was mostly offset by milder weather in the second quarter. Weather in the third quarter, while significantly warmer than normal, was cooler than third quarter of 2013. Compared to the nine months ended September 30, 2013, residential electric use per customer decreased 0.7 percent and commercial use per customer decreased 0.4 percent. Cooling degree days at Spokane were 60 percent above average, but 11 percent below the nine months ended September 30, 2013.

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 increased $7.0 million due to an increase in sales prices (increased revenues $11.3 million), partially offset by a decrease in sales volumes (decreased revenues $4.3 million). The fluctuation in volumes and prices was primarily the result of our optimization activities during the period.

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 $37.5 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 nine months ended September 30, 2014, $45.9 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For the nine months ended September 30, 2013, $76.9 million of these sales were made to our natural gas operations.

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

Other electric revenues decreased $9.5 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 nine months ended September 30, 2014, we estimated a provision for earnings sharing of $6.2 million for Idaho electric customers with $4.3 million representing our estimate for the nine months ended September 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 nine months ended September 30 (dollars and therms in thousands):

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2014	2013	2014	2013
Residential	$ 135,954	$ 127,742	125,329	125,075
Commercial	70,136	64,497	78,936	77,297
Interruptible	1,997	1,807	3,648	3,914
Industrial	3,071	2,532	4,125	3,693
Total retail	211,158	196,578	212,038	209,979
Wholesale	167,471	133,573	387,772	374,142
Transportation	5,658	5,435	118,726	114,084
Other	5,670	6,286	315	300
Provision for earnings sharing	(1,053)	—	—	—
Total	$ 388,904	$ 341,872	718,851	698,505

Retail natural gas revenues increased $14.6 million primarily due to higher retail rates (increased revenues $12.5 million) and partially due to an increase in volumes (increased revenues $2.1 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 nine months ended September 30, 2014 as compared to the nine months ended September 30, 2013 primarily due to customer growth and colder weather in the first quarter, partially offset by milder weather in the second and third quarters. Compared to the nine months ended September 30, 2013, residential natural gas use per customer decreased 0.9 percent and commercial use per customer increased 1.9 percent. Heating degree days at Spokane were 6 percent below historical average for the nine months ended September 30, 2014, and 1 percent below the nine months ended September 30, 2013. Heating degree days at Medford were 23 percent below historical average for the nine months ended September 30, 2014 and 18 percent below the nine months ended September 30, 2013.

Wholesale natural gas revenues increased $33.9 million due to an increase in prices (increased revenues $28.0 million) and an increase in volumes (increased revenues $5.9 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 nine months ended September 30, 2014, $58.2 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In the nine months ended September 30, 2013, $28.6 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 nine months ended September 30:

	Electric Customers		Natural Gas Customers	
	2014	2013	2014	2013
Residential	323,540	320,461	291,366	288,253
Commercial	40,930	40,133	34,031	33,958
Interruptible	—	—	37	38
Industrial	1,388	1,386	263	260
Public street and highway lighting	532	526	—	—
Total retail customers	366,390	362,506	325,697	322,509

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

	2014	2013
Electric resource costs:		
Power purchased	$ 139,144	$ 144,582
Power cost amortizations, net	(6,217)	(7,188)
Fuel for generation	83,602	90,672
Other fuel costs	54,723	93,103
Other regulatory amortizations, net	16,185	16,478
Other electric resource costs	15,463	17,035
Total electric resource costs	302,900	354,682
Natural gas resource costs:		
Natural gas purchased	286,315	235,803
Natural gas cost amortizations, net	(11,373)	(2,277)
Other regulatory amortizations, net	4,331	4,524
Total natural gas resource costs	279,273	238,050
Intracompany resource costs	(104,163)	(105,455)
Total resource costs	$ 478,010	$ 487,277

Power purchased decreased $5.4 million due to a decrease in the volume of power purchases (decreased costs $17.6 million), partially offset by an increase in wholesale prices (increased costs $12.2 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 $6.2 million for the nine months ended September 30, 2014 compared to $7.2 million for the nine months ended September 30, 2013. During the nine months ended September 30, 2014, we refunded to customers $3.5 million of previously deferred power costs in Idaho through the PCA rebate. We also refunded to Washington customers $6.3 million through an ERM rebate. During the nine months ended September 30, 2014, actual power supply costs were below the amount included in base retail rates in Washington and we deferred $4.9 million for probable future benefit to customers. We deferred $1.3 million in Idaho for probable future sucharge to customers.

Fuel for generation decreased $7.1 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 $38.4 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 $1.6 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 $50.5 million primarily due to an increase in the price of natural gas (increased costs $43.0 million) and partially due to an increase in total therms purchased (increased costs $7.5 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, and 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.

Alaska Electric Light and Power Company

As noted above, AEL&P was acquired on July 1, 2014 and only the results for the third quarter of 2014 are included in the actual overall results of Avista Corp; therefore, only the three months ended September 30, 2014 are shown.

Three months ended September 30, 2014

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

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

	Electric
	2014
Operating revenues	$ 9,157
Resource costs	2,997
Gross margin	$ 6,160

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

	Electric Operating Revenues	Electric Energy MWh sales
	2014	2014
Residential	$ 3,135	26
Commercial	4,523	46
Government sales	1,306	15
Public street and highway lighting	73	1
Total retail	9,037	88
Other	120	—
Total	$ 9,157	88

AEL&P's operating revenues were $9.2 million and its resource costs were $3.0 million, which resulted in gross margin of $6.2 million, and it was all related to electric sales. Retail revenues for the current period were derived from weather that was warmer than normal with heating degree days that were 12 percent below normal. There were no cooling degree days during the third quarter of 2014. AEL&P is winter peaking and does not have significant cooling loads during the summer. Government sales are similar to commercial sales in that they are primarily firm customers, but are government entities.

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

	Electric Customers
	2014
Residential	14,242
Commercial	1,717
Government	443
Public street and highway lighting	212
Total retail customers	16,614

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

	2014
Snettisham power expenses	$ 2,607
Power cost amortizations, net	366
Fuel for generation	24
Total electric resource costs	$ 2,997

Snettisham power expenses represent costs associated with running the Snettisham hydroelectric project, which is a power purchase agreement that is recorded as a capital lease on AEL&P's balance sheet, but reflected as an operating lease in the income statement. See "Note 9 of the Notes to Consolidated Financial Statements" for further information regarding this capital lease obligation.

Power cost amortizations are primarily derived from certain revenues from interruptible or non-firm customers that are deferred and passed on for the benefit of firm customers in future periods. For instance all cruise ship revenue is passed back to firm customers at 100 percent. The amortization of these deferred balances flows through this account along with the original deferral.

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.

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

Ecova incurred a net loss $0.1 million for the three months ended September 30, 2014 compared to net income of $3.0 million for the three months ended September 30, 2013. The net loss for the third quarter of 2014 was the result of the true-up of disposition transaction expenses during the quarter.

Nine months ended September 30, 2014 compared to the nine months ended September 30, 2013

Ecova's net income attributable to Avista Corp. shareholders was $70.8 million for the nine months ended September 30, 2014 compared to $5.8 million for the nine months ended September 30, 2013. The increase was primarily attributable to the net gain recognized on the sale of Ecova of $68.0 million. Excluding the net gain, net income from Ecova's regular operations through the date of the sale were flat compared to the same period in 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. In addition, as of July 1, 2014 we own AERC and AJT Mining, which is a wholly-owned subsidiary of AERC and is an inactive mining company holding certain properties. These activities do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp., including AM&D, doing business as METALfx.

The following table shows our assets related to our other businesses as of September 30, 2014 and December 31, 2013 (dollars in thousands):

	September 30, 2014	December 31, 2013
Spokane Energy (1)	$ 33,606	$ 42,829
Avista Energy	1,122	12,399
METALfx	12,061	11,105
Steam Plant and Courtyard Office Center	7,538	7,055
Alaska companies (AERC and AJT Mining)	8,222	—
Other (2)	21,065	7,894
Total	$ 83,614	$ 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) The balance at September 30, 2014 includes $13.6 million in escrow amounts related to the sale of Ecova and net cash of $1.4 million held at Avista Capital.

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

The net loss from these operations was $0.4 million for the three months ended September 30, 2014 compared to a net loss of $1.1 million for the three months ended September 30, 2013. The net loss for the third quarter of 2014 was primarily the result of $0.6 million (net of tax) of corporate costs, including costs associated with exploring strategic opportunities. This was offset by METALfx net income of $0.3 million for the third quarter of 2014, which compares to net income of $0.5 million for the third quarter of 2013. Lastly, the Alaska subsidiaries (AERC and AJT Mining) had net income of less than $0.1 million for the third quarter of 2014.

Nine months ended September 30, 2014 compared to the nine months ended September 30, 2013

The net income from these operations was $3.5 million for the nine months ended September 30, 2014 compared to a net loss of $2.6 million for the nine months ended September 30, 2013. The net income for the first nine months 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 $0.6 million for the first nine months of 2014, compared to net income of $1.1 million for the first nine months of 2013 and we incurred approximately $1.7 million (net of tax) of corporate costs, including costs associated with exploring strategic opportunities. Lastly, the Alaska subsidiaries (AERC and AJT Mining) had net income of less than $0.1 million for the third quarter of 2014.

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 except as follows.

On July 1, 2014, we acquired AERC, along with its primary operating subsidiary AEL&P. We determined that beginning July 1, 2014, AEL&P is a reportable business segment and AERC and its other stand-alone subsidiaries (AJT Mining and the Snettisham Electric Company) are not reportable business segments and will be included in the Other category for segment reporting. Our conclusion is based on the following:

- As of the acquisition date, each stand-alone operating subsidiary individually and consolidated do not meet the quantitative thresholds of a reportable business segment (generally 10 percent of revenue, net income or assets); therefore our determination of segment reporting is based on qualitative information.

- While AERC and its various subsidiaries each have separate revenue streams and incur expenses and they have discrete financial information available, only the AEL&P financial results are reviewed in detail by the Chief Operating Decision Maker (CODM). The CODM evaluates the performance of AEL&P by reviewing the income (loss) from operations before income taxes as well as net income (loss) attributable to Avista Corp. shareholders.
- Allocation of resources for the Alaska operations is generally determined by reviewing the financial results of AEL&P, without significant regard to the other subsidiaries of AERC.
- Even though AEL&P is a regulated utility similar to Avista Utilities, the economic characteristics (including financial results, geographical region and regulatory environment) of AEL&P are sufficiently different from those of Avista Utilities that it should not be aggregated with the Avista Utilities reportable segment.
- AEL&P is an important operating segment for our consolidated company and even though it does not meet the quantitative thresholds for a reportable business segment, we have elected to report it as a separate segment.

In addition to AEL&P being a reportable business segment, we determined that AEL&P is also the reporting unit for which the acquired goodwill was assigned. There is no lower level below this operating segment that the acquired goodwill is attributable to.

Liquidity and Capital Resources

Overall Liquidity

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

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

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

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

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

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

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 September 30, 2014, we had $319.4 million of available liquidity under the Avista Corp. committed line of credit. With our $400.0 million credit facility that expires in April 2019, we believe that we have adequate liquidity to meet our needs for the next 12 months.

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

Review of Cash Flow Statement

Overall

During the nine months ended September 30, 2014, positive cash flows from operating activities were $265.7 million. Cash requirements included utility capital expenditures of $229.8 million, dividends of $58.6 million, the repayment of short-term borrowings of $136.0 million, contributions to our pension plan of $32.0 million and the repurchase of common stock of $61.0 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), which has been included in investing activities. For the first nine months of 2014, we made tax payments of $22.5 million, net of tax receipts of $35.2 million. In July 2014, we utilized a portion of the Ecova 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 $265.7 million for the nine months ended September 30, 2014 compared to $202.4 million for the nine months ended September 30, 2013. Net cash provided by fluctuations in certain current assets and liabilities was $56.9 million for the first nine months of 2014, compared to net cash provided of $5.6 million for the first nine months of 2013. The net cash provided by certain current assets and liabilities during the first nine months of 2014 primarily reflects positive cash flows related to accounts receivable, income taxes payable and other current liabilities (primarily related to fluctuations in accrued taxes, accrued interest, and other miscellaneous accrued liabilities). These positive cash flows were partially offset by net cash outflows related to accounts payable and materials and supplies, fuel stock and natural gas stored.

The net cash provided by certain current assets and liabilities during the first nine months of 2013 primarily reflects positive cash flows related to accounts receivable and other current liabilities (primarily related to fluctuations in accrued taxes, accrued interest, and other miscellaneous accrued liabilities). These positive cash flows were partially offset by net cash outflows related to accounts payable, other current assets, and materials and supplies, fuel stock and natural gas stored.

The gross gain on the sale of Ecova of $161.1 million for the first nine months of 2014 was excluded from operating cash flows and included in investing activities. Net deferrals of power and natural gas costs decreased operating cash flows by $18.0 million for the nine months ended September 30, 2014 compared to a decrease in operating cash flows of $10.1 million for the nine months ended September 30, 2013. The provision for deferred income taxes was $111.3 million for the nine months ended September 30, 2014 compared to $16.5 million for the nine months ended September 30, 2013. The 2014 amount was primarily related to the recording of $50.0 million associated with the planned adoption by the Company of new federal tax tangible property regulations. Contributions to our defined benefit pension plan were $32.0 million for the first nine months of 2014 and $44.0 million for the first nine months of 2013. Net cash paid for income taxes was $22.5 million for the first nine months of 2014, net of tax receipts of $35.2 million, compared to cash paid of $33.5 million for the first nine months of 2013, net of tax receipts of $5.0 million.

Investing Activities

Net cash used in investing activities was $6.8 million for the nine months ended September 30, 2014, compared to net cash used of $233.6 million for the nine months ended September 30, 2013. During the first nine months of 2014, we received cash proceeds (net of cash sold and escrow amounts) of $229.9 million related to the sale of Ecova. A portion of the proceeds from the Ecova sale was used to pay off the balance of Ecova's long-term borrowings and make payments to option holders and noncontrolling interests (included in financing activities). We also used a portion of these proceeds to pay our tax liability associated with the gain on sale. Utility property capital expenditures increased by $9.1 million for the first nine months of 2014 as compared to the first nine months 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 $35.9 million and sales and maturities of $17.0 million for 2013. The fluctuation in the balance of funds held for customers resulted in a decrease to cash of $18.9 million compared to an increase to cash of $11.7 million for 2013. We received $15.0 million in cash (net of cash paid) related to the acquisition of AERC during 2014.

Financing Activities

Net cash used in financing activities was $331.1 million for the nine months ended September 30, 2014 compared to net cash provided of $47.7 million for the nine months ended September 30, 2013. During the first nine months of 2014, short-term borrowings on Avista Corp.'s committed line of credit decreased $136.0 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 September 2014, AEL&P issued $75.0 million of long-term debt. The majority of the $39.4 million of retirements of long-term debt in 2014 relates to AEL&P paying off its existing debt.

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 $58.6 million (or $0.9525 per share) for the first nine months of 2014 from $55.0 million (or $0.915 per share) for the first nine months of 2013. We issued $3.4 million of common stock during the nine months ended September 30, 2014 and $150.1 million of common stock issued to AERC shareholders is reflected as a non-cash financing activity. The fluctuation in the balance of customer fund obligations at Ecova increased cash by $16.2 million.

During the third quarter of 2014, we repurchased $61.0 million of common stock.

During the nine months ended September 30, 2013, short-term borrowings on Avista Corp.'s committed line of credit increased $14.0 million. Net borrowings on Ecova's line of credit decreased $4.0 million, with $3.0 million of borrowings and $7.0 million of repayments. We issued $4.5 million of common stock during the nine months ended September 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 $7.4 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 September 30, 2014, we had deposited cash in the amount of $7.4 million and letters of credit of $38.5 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 September 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 $10.8 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 September 30, 2014, we had interest rate swap agreements outstanding with a notional amount totaling $420.0 million and we had posted $12.7 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 September 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 September 30, 2014 and December 31, 2013 (dollars in thousands):

	September 30, 2014		December 31, 2013	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt and capital leases	$ 6,471	0.2%	$ 358	—%
Current portion of nonrecourse long-term debt (Spokane Energy)	5,666	0.2%	16,407	0.6%
Short-term borrowings	35,000	1.2%	171,000	6.0%
Long-term borrowings under committed line of credit	—	—%	46,000	1.6%
Long-term debt to affiliated trusts	51,547	1.7%	51,547	1.8%
Nonrecourse long-term debt (Spokane Energy)	—	—%	1,431	0.1%
Long-term debt and capital leases	1,412,211	47.0%	1,272,425	44.5%
Total debt	1,510,895	50.3%	1,559,168	54.6%
Total Avista Corporation shareholders’ equity	1,492,208	49.7%	1,298,266	45.4%
Total	$ 3,003,103	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 $193.9 million during the first nine months of 2014 primarily due to net income, which included the net gain on the sale of Ecova, and the issuance of common stock to AERC shareholders, partially offset by the repurchase of common stock and 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 $15.0 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.

In the nine months ended September 30, 2014, we issued $3.4 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 $150.1 million related to closing the AERC transaction. 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 expect to issue any additional shares for 2014, other than a small amount 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 expires on December 31, 2014 and we have the option to terminate the program before that date. Through October 31, 2014, we repurchased 2,529,615 shares at a total cost of $79.9 million and an average cost of $31.57 per share. All repurchased shares revert to the status of authorized but unissued shares.

In September 2014, AEL&P issued $75.0 million of 4.54 percent first mortgage bonds due in 2044. In addition to the first mortgage bonds, we expect to issue $15.0 million in term loans at AERC during the fourth quarter of 2014. We acquired AERC primarily by issuing Avista Corp. common stock. The proceeds from the new AEL&P debt were used to repay approximately $38.0 million of existing AEL&P debt and the remainder of the proceeds and cash on-hand were paid as a cash dividend of $50.0 million to Avista Corp. associated with rebalancing the consolidated capital structure at AERC.

In October 2014, we entered into a bond purchase agreement with three institutional investors in a private placement transaction for the issuance and sale of $60.0 million of Avista Corp. first mortgage bonds that are expected to be issued in December 2014. The first mortgage bonds will bear an interest rate of 4.11 percent and mature in December 2044.

For 2015, we expect to issue approximately $100.0 million of long-term debt and approximately $30.0 million of common stock in order to maintain an appropriate capital structure.

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, 1) there are no default events prior to the requested extension, and 2) the remaining term of agreement, including the requested extension period, does not exceed five years. 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.

AEL&P has a committed line of credit in the amount of $14.5 million with an expiration date of June 2015. As of September 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

September 30, 2014, we were in compliance with this covenant with a ratio of 50.3 percent.

In addition, certain requirements under the OPUC approval of the AERC acquisition, do not permit Avista Utilities' total equity to total capitalization to be less than 40 percent, without approval from the OPUC. We were in compliance with this requirement as well.

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 nine months ended September 30 (dollars in thousands):

	2014	2013
Borrowings outstanding at end of period	$ 35,000	$ 66,000
Letters of credit outstanding at end of period	$ 45,614	$ 27,994
Maximum borrowings outstanding during the period	$ 171,000	$ 95,500
Average borrowings outstanding during the period	$ 55,778	$ 23,382
Average interest rate on borrowings during the period	1.03%	1.18%
Average interest rate on borrowings at end of period	0.92%	1.10%

Any default on the line of credit or other financing arrangements of Avista Corp. or any of our “significant subsidiaries,” if any, could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Any defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock. Avista Corp. does not guarantee the indebtedness of any of its subsidiaries. As of September 30, 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 $355.0 million in 2014, $355.0 million in 2015 and $350.0 million in 2016. In addition, we expect to spend approximately $3.0 million for 2014 and $15.0 million for each of 2015 and 2016 related to capital expenditures at AEL&P. Most of Avista Utilities' 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 September 30, 2014 we have spent $76.4 million on the project (including internal labor).

Off-Balance Sheet Arrangements

As of September 30, 2014, we had $45.6 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

Avista Utilities

In the nine months ended September 30, 2014 we contributed $32.0 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 IBEW 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 November 5, 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 2. Management's Discussion and Analysis - "Capital Resources" for compliance with these covenants),
- the hydroelectric licensing requirements of section 10(d) of the FPA (see “Note 1 of Notes to Condensed Consolidated Financial Statements”), and
- certain requirements under the OPUC approval of the AERC acquisition, which does not permit one-time or special dividends from AERC to Avista Corp. and which does not permit Avista Utilities' total equity to total capitalization to be less than 40 percent, without approval from the OPUC. The OPUC approval does allow for special or one-time dividends during the first year after closing to recapitalize AERC as part of the transaction and it also allows for regular distributions of AERC earnings to Avista Corp. as long as AERC remains sufficiently capitalized and insured.

On August 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 nine months ended September 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 certain contractual obligations associated with our acquisition of AERC. In addition, we had one contractual commitment associated with Avista Capital that was added during nine months ended September 30, 2014. 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						
AERC - effective July 1, 2014						
Long-term debt maturities (5)	—	—	—	—	—	75
Interest payment on long-term debt (5)	1	3	3	3	3	88
Capital lease obligations (3)	1	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
Pension plan and other postretirement funding (8)	1	3	3	3	3	—
Avista Capital (consolidated)						
Investment funding (9)	—	1	1	1	—	—
Total contractual obligations added	$ 5	$ 18	$ 18	$ 18	$ 17	$ 321

(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 on the long-term debt that was issued during September 2014. For further discussion of this debt see "Item 2. Management's Discussion and Analysis: Executive Level Summary."
(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.
(8) Represents our estimated cash contributions to the pension plan and other postretirement benefits through 2018. We cannot reasonably estimate pension plan and other postretirement benefit contributions beyond 2018 at this time and have excluded them from the table above.
(9) Represents a commitment to fund a limited liability company in exchange for equity ownership, made by a subsidiary of Avista Capital.

Economic Conditions

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

We track multiple economic indicators affecting three distinct metropolitan statistical areas in our Pacific Northwest 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, September 2014 showed both 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 Pacific Northwest 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 September 2013 and September 2014. In Spokane, Washington employment increased 0.3 percent with gains in mining, logging, and construction; financial activities; education and health services; and government. Employment increased 4 percent in Coeur d'Alene, Idaho, reflecting gains in construction; professional and business services; education and health services; leisure and hospitality; and government. In Medford, Oregon, employment declined 0.6 percent, with gains in manufacturing; education and health services; and government offset by declines in trade, transportation and utilities; information; and financial activities. U.S. nonfarm sector jobs grew 1.9 percent in the same twelve-month period.

Seasonally adjusted unemployment rates went down in September 2014 from the year earlier in Spokane, Coeur d'Alene, and Medford. In Spokane the rate was 7.6 percent in September 2013 and declined to 6.0 percent in September 2014; in Coeur d'Alene the rate went from 6.9 percent to 5.1 percent; and in Medford the rate declined from 9.3 percent to 8.6 percent. The U.S. rate declined from 7.2 percent to 5.9 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 September 2014 national rate was 0.08 percent, compared to 0.07 percent in Spokane County, Washington; 0.06 percent in Kootenai County (Coeur d'Alene), Idaho; and 0.03 percent in Jackson County (Medford), Oregon.

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

The Quarterly Census of Employment and Wages for the CBJ shows employment declined 2.2 percent between first quarter 2013 and first quarter 2014. A significant portion of this decline was to due to a contraction in government employment, which is the CBJ’s largest single sector. Government (including active duty military personnel) accounts for approximately 37 percent of total employment. Employment gains did occur in manufacturing; professional and business services; and leisure and hospitality. Between August 2013 and August 2014 the non-seasonally adjusted unemployment rate increased from 4.1 percent to 4.5 percent.

The CBJ foreclosure rate is below the U.S. rate. The August 2014 rate was 0.02 percent compared to 0.09 percent for the U.S.

Environmental Issues and Contingencies

Our environmental issues and contingencies disclosures have not materially changed except for the following during the nine months ended September 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 GHG emissions from covered existing generation sources by 30 percent nationally by 2030 from a 2005 baseline. 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 December 1, 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 which is now fully operational and performing as expected. 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 nine months ended September 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 September 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	$ (303)	$ 1,116	$ (792)	$ (895)	$ 124	$ (48)	$ (212)	$ 528
2015	(2,332)	(4,642)	(1,663)	(4,295)	(12)	7,976	(623)	1,454
2016	(3,192)	659	(773)	(2,386)	(37)	3,398	(743)	(438)
2017	(2,862)	—	50	(69)	(66)	—	—	54
2018	(2,259)	—	—	—	(140)	—	—	—
Thereafter	(1,347)	—	—	—	(108)	—	—	—

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 nine months ended September 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 September 30, 2014 and December 31, 2013 (dollars in thousands):

	September 30, 2014	December 31, 2013
Number of agreements	22	11
Notional amount	$ 420,000	$ 245,000
Mandatory cash settlement dates	2014 to 2018	2014 to 2018
Short-term derivative assets (1)	$ 7,106	$ 13,968
Long-term derivative assets (1)	1,147	19,575
Long-term derivative liability (1) (2)	(16,708)	—

(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 September 30, 2014 reflects the offsetting of $12.7 million of cash collateral against the net derivative positions where a legal right of offset exists.

In October 2014, the Company cash settled two interest rate swap contracts (notional aggregate amount of $50.0 million) and received a total of $5.4 million. The interest rate swap contracts were settled in connection with the pricing of $60.0 million of Avista Corp. first mortgage bonds that are expected to be issued in December 2014.

In anticipation of issuing long-term debt in 2018, we entered into two interest rate swap agreements in October 2014, with a total aggregate notional amount of $50.0 million and a mandatory cash settlement date of June 2018. Including the October 2014 interest rate swap agreements, we have a total of nine interest rate swap agreements with an aggregate notional amount of $205.0 million related to the anticipated long-term debt issuance in 2018.

Foreign Currency Risk

Our qualitative foreign currency risk disclosures have not materially changed during the nine months ended September 30, 2014. See the 2013 Form 10-K.

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

	September 30, 2014	December 31, 2013
Number of contracts	23	23
Notional amount (in United States dollars)	$ 15,734	$ 8,631
Notional amount (in Canadian dollars)	17,326	9,191
Other current derivative asset (liability)	(280)	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 September 30, 2014.

There have been no changes in the Company's internal control over financial reporting that occurred during the third 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 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) Not applicable

(b) Not applicable

(c) Issuer Purchases of Equity Securities

The following table provides information about share repurchases that we made during the three months ended September 30, 2014 (in thousands, except per share amounts):

	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Program	(d) Maximum Number of Shares that May Yet Be Purchased Under the Program
July 1 to July 31, 2014	292	$ 32.30	292	3,708
August 1 to August 31, 2014	927	31.50	927	2,781
September 1 to September 30, 2014	705	31.67	705	2,076
Total	1,924	$ 31.68	1,924	2,076

On June 13, 2014, our Board of Directors approved a program to repurchase up to 4 million shares of the Company’s outstanding common stock, assuming the closure of the Ecova transaction. Repurchases of common stock under this program commenced on July 7, 2014 and the program expires on December 31, 2014. We can 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 October 31, 2014, we repurchased 2,529,615 shares at a total cost of $79.9 million and an average cost of $31.57 per share. All repurchased shares revert to the status of authorized but unissued shares.

Dividend Limitations

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

Item 4. Mine Safety Disclosures

Not applicable.

Item 6. Exhibits

12	Computation of ratio of earnings to fixed charges*
15	Letter Re: Unaudited Interim Financial Information*
31.1	Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002)*
31.2	Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002)*
32	Certification of Corporate Officers (Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)**
101	The following financial information from the Quarterly Report on Form 10−Q for the period ended September 30, 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: November 5, 2014

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

Exhibit 12

AVISTA CORPORATION

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

	Nine months ended September 30, 2014	Years Ended December 31 2013	2012	2011	2010	2009
Fixed charges, as defined:						
Interest charges	$ 54,452	$ 75,409	$ 73,633	$ 69,591	$ 72,010	$ 61,361
Amortization of debt expense and premium - net	2,771	3,813	3,803	4,617	4,414	5,673
Interest portion of rentals	875	2,762	2,717	2,154	2,027	1,874
Total fixed charges	$ 58,098	$ 81,984	$ 80,153	$ 76,362	$ 78,451	$ 68,908
Earnings, as defined:						
Pre-tax income from continuing operations	$ 140,536	$ 175,524	$ 120,061	$ 160,171	$ 146,105	$ 134,971
Add (deduct):						
Capitalized interest	(2,707)	(3,676)	(2,401)	(2,942)	(298)	(545)
Total fixed charges above	58,098	81,984	80,153	76,362	78,451	68,908
Total earnings	$ 195,927	$ 253,832	$ 197,813	$ 233,591	$ 224,258	$ 203,334
Ratio of earnings to fixed charges	3.37	3.10	2.47	3.06	2.86	2.95

Exhibit 15

November 5, 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 September 30, 2014 and 2013, as indicated in our report dated November 5, 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: November 5, 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: November 5, 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 September 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: November 5, 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