UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

FOR THE QUARTERLY PERIOD ENDED September 30, 2013 OR

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

FOR THE TRANSITION PERIOD FROM TO

Commission file number 1-3701

AVISTA CORPORATION

(Exact name of Registrant as specified in its charter)

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

Registrant's telephone number, including area code: 509-489-0500

Web site: http://www.avistacorp.com

None

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

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

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

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

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

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

As of October 31, 2013, 60,036,179 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 have 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 and uncertainties and other factors. Many of these factors are beyond our control and they could have a significant effect on our operations, results of operations, financial condition or cash flows. This 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 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;
- 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;
- 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 customer demand for utility services;
- the effect of increased customer energy efficiency;
- 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;
- changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension and other postretirement medical plans, which can affect future funding obligations, pension and other postretirement medical expense and pension and other postretirement medical plan 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;
- the outcome of pending regulatory and legal proceedings arising out of the "western energy crisis" of 2000 and 2001, including possible refunds;
- the outcome of legal proceedings and other contingencies;
- changes in, and compliance with, environmental and endangered species laws, regulations, decisions and policies, including present and potential environmental remediation costs;

- wholesale and retail competition including alternative energy sources, emerging customer-owned power resource technologies, suppliers and delivery arrangements and the extent that new uses for our services may materialize;
- the ability to comply with the terms of the licenses for our hydroelectric generating facilities at cost-effective levels;
- severe weather or natural disasters that can disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies and support services;
- explosions, fires, accidents, mechanical breakdowns, or other incidents that may cause unplanned outages at any of our generation facilities, transmission and distribution systems or other operations;
- public injuries or damages 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;
- 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 Pacific Northwest 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;
- 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 certain ratings trigger covenants in our financing arrangements and wholesale energy contracts;
- increasing health care costs and the resulting effect on health insurance provided to our employees and retirees;
- increasing costs of insurance, more restricted coverage terms and our ability to obtain insurance;
- work force issues, including changes in collective bargaining unit agreements, strikes, work stoppages or 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 the payment acceptance policies of Ecova's client vendors that could reduce operating revenues;
- potential difficulties for Ecova 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; and
- 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.

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.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

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

	2013	2012
Operating Revenues:		
Utility revenues	$ 278,473	$ 292,085
Ecova revenues	46,398	38,617
Other non-utility revenues	11,004	9,930
Total operating revenues	335,875	340,632
Operating Expenses:		
Utility operating expenses:		
Resource costs	131,136	153,801
Other operating expenses	69,596	66,456
Depreciation and amortization	29,823	28,255
Taxes other than income taxes	18,712	18,122
Ecova operating expenses:		
Other operating expenses	37,047	33,868
Depreciation and amortization	3,909	3,260
Other non-utility operating expenses:		
Other operating expenses	10,212	10,131
Depreciation and amortization	171	131
Total operating expenses	300,606	314,024
Income from operations	35,269	26,608
Interest expense	19,566	19,128
Interest expense to affiliated trusts	117	136
Capitalized interest	(820)	(644)
Other (income) expense-net	(984)	418
Income before income taxes	17,390	7,570
Income tax expense	5,459	1,608
Net income	11,931	5,962
Net income attributable to noncontrolling interests	(518)	(176)
Net income attributable to Avista Corporation shareholders	$ 11,413	$ 5,786
Weighted-average common shares outstanding (thousands), basic	59,994	59,047
Weighted-average common shares outstanding (thousands), diluted	60,032	59,123
Earnings per common share attributable to Avista Corporation shareholders:		
Basic	$ 0.19	$ 0.10
Diluted	$ 0.19	$ 0.10
Dividends paid per common share	$ 0.305	$ 0.29

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)

	2013	2012
Operating Revenues:		
Utility revenues	$ 1,007,319	$ 990,860
Ecova revenues	133,365	115,707
Other non-utility revenues	30,145	29,907
Total operating revenues	1,170,829	1,136,474
Operating Expenses:		
Utility operating expenses:		
Resource costs	487,277	500,805
Other operating expenses	200,824	196,759
Depreciation and amortization	86,783	83,327
Taxes other than income taxes	66,137	63,723
Ecova operating expenses:		
Other operating expenses	110,753	104,392
Depreciation and amortization	11,474	9,455
Other non-utility operating expenses:		
Other operating expenses	28,972	28,480
Depreciation and amortization	536	511
Total operating expenses	992,756	987,452
Income from operations	178,073	149,022
Interest expense	59,119	57,453
Interest expense to affiliated trusts	352	413
Capitalized interest	(2,702)	(1,765)
Other income-net	(5,565)	(2,892)
Income before income taxes	126,869	95,813
Income tax expense	46,107	33,106
Net income	80,762	62,707
Net income attributable to noncontrolling interests	(1,351)	(355)
Net income attributable to Avista Corporation shareholders	$ 79,411	$ 62,352
Weighted-average common shares outstanding (thousands), basic	59,933	58,778
Weighted-average common shares outstanding (thousands), diluted	59,964	59,026
Earnings per common share attributable to Avista Corporation shareholders:		
Basic	$ 1.32	$ 1.06
Diluted	$ 1.32	$ 1.06
Dividends paid per common share	$ 0.915	$ 0.87

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)

	2013	2012
Net income	$ 11,931	$ 5,962
Other Comprehensive Income (Loss):		
Unrealized investment gains/(losses) - net of taxes of $(233) and $68, respectively	(395)	110
Reclassification adjustment for realized gains on investment securities included in net income - net of taxes of $(1) and $(11), respectively	(1)	(17)
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $99 and $90, respectively	184	168
Total other comprehensive income (loss)	(212)	261
Comprehensive income	11,719	6,223
Comprehensive income attributable to noncontrolling interests	(518)	(176)
Comprehensive income attributable to Avista Corporation shareholders	$ 11,201	$ 6,047

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

	2013	2012
Net income	$ 80,762	$ 62,707
Other Comprehensive Income (Loss):		
Unrealized investment gains/(losses) - net of taxes of $(993) and $244, respectively	(1,687)	409
Reclassification adjustment for realized gains on investment securities included in net income - net of taxes of $(8) and $(94), respectively	(12)	(158)
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $297 and $263, respectively	551	489
Total other comprehensive income (loss)	(1,148)	740
Comprehensive income	79,614	63,447
Comprehensive income attributable to noncontrolling interests	(1,351)	(355)
Comprehensive income attributable to Avista Corporation shareholders	$ 78,263	$ 63,092

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands
(Unaudited)

	September 30, 2013	December 31, 2012
Assets:		
Current Assets:		
Cash and cash equivalents	$ 91,979	$ 75,464
Accounts and notes receivable-less allowances of $44,103 and $44,155, respectively	139,512	193,683
Utility energy commodity derivative assets	3,430	4,139
Regulatory asset for utility derivatives	20,399	35,082
Investments and funds held for clients	92,870	88,272
Materials and supplies, fuel stock and natural gas stored	56,843	47,455
Deferred income taxes	28,740	34,281
Income taxes receivable	12,350	2,777
Other current assets	39,721	24,641
Total current assets	485,844	505,794
Net Utility Property:		
Utility plant in service	4,252,299	4,054,644
Construction work in progress	137,565	143,098
Total	4,389,864	4,197,742
Less: Accumulated depreciation and amortization	1,232,547	1,174,026
Total net utility property	3,157,317	3,023,716
Other Non-current Assets:		
Investment in exchange power-net	14,496	16,333
Investment in affiliated trusts	11,547	11,547
Goodwill	76,762	75,959
Intangible assets-net of accumulated amortization of $33,886 and $26,030, respectively	41,153	46,256
Long-term energy contract receivable of Spokane Energy	43,563	52,033
Other property and investments-net	66,486	46,542
Total other non-current assets	254,007	248,670
Deferred Charges:		
Regulatory assets for deferred income tax	67,691	79,406
Regulatory assets for pensions and other postretirement benefits	292,359	306,408
Other regulatory assets	105,608	103,946
Non-current utility energy commodity derivative assets	293	1,093
Non-current regulatory asset for utility derivatives	24,729	25,218
Other deferred charges	14,154	18,928
Total deferred charges	504,834	534,999
Total assets	$ 4,402,002	$ 4,313,179

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

Dollars in thousands
(Unaudited)

	September 30, 2013	December 31, 2012
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 158,360	$ 198,914
Client fund obligations	95,214	87,839
Current portion of long-term debt	50,330	50,372
Current portion of nonrecourse long-term debt of Spokane Energy	16,022	14,965
Short-term borrowings	66,000	52,000
Utility energy commodity derivative liabilities	18,708	29,515
Other current liabilities	145,602	142,544
Total current liabilities	550,236	576,149
Long-term debt	1,272,260	1,178,367
Nonrecourse long-term debt of Spokane Energy	5,666	17,838
Long-term debt to affiliated trusts	51,547	51,547
Long-term borrowings under committed line of credit	50,000	54,000
Regulatory liability for utility plant retirement costs	249,980	234,128
Pensions and other postretirement benefits	252,331	283,985
Deferred income taxes	528,981	524,877
Other non-current liabilities and deferred credits	122,214	110,215
Total liabilities	3,083,215	3,031,106
Commitments and Contingencies (See Notes to Condensed Consolidated Financial Statements)		
Redeemable Noncontrolling Interests	8,330	4,938
Equity:		
Avista Corporation Stockholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 60,029,209 and 59,812,796 shares outstanding, respectively	898,199	889,237
Accumulated other comprehensive loss	(7,848)	(6,700)
Retained earnings	399,053	376,940
Total Avista Corporation stockholders' equity	1,289,404	1,259,477
Noncontrolling Interests	21,053	17,658
Total equity	1,310,457	1,277,135
Total liabilities and equity	$ 4,402,002	$ 4,313,179

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)

	2013	2012
Operating Activities:		
Net income	$ 80,762	$ 62,707
Non-cash items included in net income:		
Depreciation and amortization	98,793	93,293
Provision for deferred income taxes	16,512	18,380
Power and natural gas cost amortizations (deferrals), net	(10,149)	10,418
Amortization of debt expense	2,841	2,876
Amortization of investment in exchange power	1,838	1,838
Stock-based compensation expense	4,718	4,539
Equity-related AFUDC	(4,341)	(2,875)
Pension and other postretirement benefit expense	31,894	29,785
Amortization of Spokane Energy contract	8,470	7,786
Write-off of Reardan wind generation capitalized costs	2,534	—
Other	6,889	8,911
Contributions to defined benefit pension plan	(44,000)	(44,000)
Changes in working capital components:		
Accounts and notes receivable	50,681	61,106
Materials and supplies, fuel stock and natural gas stored	(9,388)	941
Other current assets	(23,165)	7,209
Accounts payable	(23,756)	(10,783)
Other current liabilities	11,269	5,277
Net cash provided by operating activities	202,402	257,408
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(220,712)	(178,440)
Other capital expenditures	(1,725)	(3,908)
Federal grant payments received	2,631	5,902
Cash paid by subsidiaries for acquisitions, net of cash received	—	(50,310)
Decrease (increase) in funds held for clients	11,723	(9,599)
Purchase of securities available for sale	(35,949)	(88,843)
Sale and maturity of securities available for sale	16,955	103,545
Other	(6,481)	(7,412)
Net cash used in investing activities	(233,558)	(229,065)

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

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

	2013	2012
Financing Activities:		
Net increase in short-term borrowings	$ 14,000	$ 21,000
Borrowings from Ecova line of credit	3,000	28,000
Repayment of borrowings from Ecova line of credit	(7,000)	(5,000)
Proceeds from issuance of long-term debt	90,000	—
Redemption and maturity of long-term debt	(415)	(11,363)
Maturity of nonrecourse long-term debt of Spokane Energy	(11,115)	(10,153)
Long-term debt and short-term borrowing issuance costs	(471)	(177)
Cash received (paid) for settlement of interest rate swap agreements	2,901	(18,547)
Issuance of common stock	4,479	28,699
Cash dividends paid	(54,963)	(51,215)
Purchase of subsidiary noncontrolling interest	(379)	(917)
Increase (decrease) in client fund obligations	7,375	(5,220)
Issuance of subsidiary noncontrolling interest	—	3,714
Other	259	1,126
Net cash provided by (used in) financing activities	47,671	(20,053)
Net increase in cash and cash equivalents	16,515	8,290
Cash and cash equivalents at beginning of period	75,464	74,662
Cash and cash equivalents at end of period	$ 91,979	$ 82,952
Supplemental Cash Flow Information:		
Cash paid during the period:		
Interest	$ 45,633	$ 43,487
Income taxes	33,522	12,527
Non-cash financing and investing activities:		
Accounts payable for capital expenditures	4,313	3,556
Valuation adjustment for redeemable noncontrolling interests	3,246	(8,274)

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS

Avista Corporation

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

	2013	2012
Common Stock, Shares:		
Shares outstanding at beginning of period	59,812,796	58,422,781
Issuance of common stock	216,413	1,332,089
Shares outstanding at end of period	60,029,209	59,754,870
Common Stock, Amount:		
Balance at beginning of period	$ 889,237	$ 855,188
Equity compensation expense	4,490	3,354
Issuance of common stock, net of issuance costs	4,479	28,699
Equity transactions of consolidated subsidiaries	(7)	289
Balance at end of period	898,199	887,530
Accumulated Other Comprehensive Loss:		
Balance at beginning of period	(6,700)	(5,637)
Other comprehensive income	(1,148)	740
Balance at end of period	(7,848)	(4,897)
Retained Earnings:		
Balance at beginning of period	376,940	336,150
Net income attributable to Avista Corporation shareholders	79,411	62,352
Cash dividends paid (common stock)	(54,963)	(51,215)
Expiration of subsidiary noncontrolling interests redemption rights	—	23,805
Valuation adjustments and other noncontrolling interests activity	(2,335)	6,019
Balance at end of period	399,053	377,111
Total Avista Corporation stockholders’ equity	1,289,404	1,259,744
Noncontrolling Interests:		
Balance at beginning of period	17,658	174
Net income attributable to noncontrolling interests	1,232	234
Deconsolidation of variable interest entity	—	(673)
Purchase of subsidiary noncontrolling interests	—	(117)
Expiration of subsidiary noncontrolling interests redemption rights	—	17,790
Other	2,163	30
Balance at end of period	21,053	17,438
Total equity	$ 1,310,457	$ 1,277,182
Redeemable Noncontrolling Interests:		
Balance at beginning of period	$ 4,938	$ 51,809
Net income attributable to noncontrolling interests	119	121
Issuance of subsidiary noncontrolling interests	—	3,714
Purchase of subsidiary noncontrolling interests	(379)	(784)
Expiration of subsidiary noncontrolling interests redemption rights	—	(41,595)
Valuation adjustments and other noncontrolling interests activity	3,652	(6,539)
Balance at end of period	$ 8,330	$ 6,726

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, 2013 and 2012 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, 2012 (2012 Form 10-K). Please refer to the section “Acronyms and Terms” in the 2012 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 Corporation is an energy company engaged in the generation, transmission and distribution of energy, as well as other energy-related businesses. Avista Utilities is an operating division of Avista Corp., comprising the regulated utility operations. Avista Utilities generates, transmits and distributes electricity in parts of eastern Washington, northern Idaho, and Montana. In addition, Avista Utilities has electric generating facilities in northern Oregon. Avista Utilities also provides natural gas distribution service in parts of eastern Washington and northern Idaho, as well as parts of northeastern and southwestern Oregon. 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). Avista Capital’s subsidiaries include Ecova, Inc. (Ecova), a 78.9 percent owned subsidiary as of September 30, 2013. Ecova is 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 12 for business segment information.

Basis of Reporting

The condensed consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries, including Ecova and other majority owned subsidiaries and variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Intercompany balances were eliminated in consolidation. The accompanying condensed consolidated financial statements include the Company’s proportionate share of utility plant and related operations resulting from its interests in jointly owned plants.

Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on 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,	
	2013	2012	2013	2012
Utility taxes	$ 10,901	$ 10,741	$ 41,045	$ 41,353

Other (Income)/Expense-Net

Other (Income)/Expense-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,	
	2013	2012	2013	2012
Interest income	$ (124)	$ (166)	$ (620)	$ (804)
Interest income on regulatory deferrals	(27)	(19)	(48)	(43)
Equity-related AFUDC	(1,595)	(1,127)	(4,341)	(2,875)
Net loss on investments	1,299	2,430	1,543	2,957
Other income	(537)	(700)	(2,099)	(2,127)
Total	$ (984)	$ 418	$ (5,565)	$ (2,892)

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, 2013 and December 31, 2012 (dollars in thousands):

	September 30, 2013	December 31, 2012
Materials and supplies	$ 29,334	$ 26,058
Fuel stock	3,750	4,121
Natural gas stored	23,759	17,276
Total	$ 56,843	$ 47,455

Investments and Funds Held for Clients and Client Fund Obligations

In connection with the bill paying services, Ecova collects funds from its clients and remits the funds to the appropriate utility or other service provider. Some of the funds collected are invested by Ecova and classified as investments and funds held for clients, and a related liability for client fund obligations is recorded. Investments and funds held for clients include cash and cash equivalent investments, money market funds and investment securities classified as available for sale. Ecova does not invest the funds directly for the clients' benefit; therefore, Ecova bears the risk of loss associated with the investments. Investments and funds held for clients as of September 30, 2013 are as follows (dollars in thousands):

	Amortized Cost (1)	Unrealized Gain (Loss)	Fair Value
Cash and cash equivalents	$ 14,155	$ —	$ 14,155
Money market funds	3,238	—	3,238
Securities available for sale:			
U.S. government agency	68,631	(2,466)	66,165
Municipal	3,529	13	3,542
Corporate fixed income – financial	3,000	4	3,004
Corporate fixed income – industrial	1,753	13	1,766
Certificates of deposit	1,000	—	1,000
Total securities available for sale	77,913	(2,436)	75,477
Total investments and funds held for clients	$ 95,306	$ (2,436)	$ 92,870

Investments and funds held for clients as of December 31, 2012 are as follows (dollars in thousands):

	Amortized Cost (1)	Unrealized Gain (Loss)	Fair Value
Cash and cash equivalents	$ 13,867	$ —	$ 13,867
Money market funds	15,084	—	15,084
Securities available for sale:			
U.S. government agency	48,340	156	48,496
Municipal	820	28	848
Corporate fixed income – financial	5,010	16	5,026
Corporate fixed income – industrial	3,887	49	3,936
Certificates of deposit	1,000	15	1,015
Total securities available for sale	59,057	264	59,321
Total investments and funds held for clients	$ 88,008	$ 264	$ 88,272

(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 are classified as a current asset since these funds are held for the purpose of satisfying the client fund obligations. As of September 30, 2013 and December 31, 2012 approximately 95 percent and 97 percent of the investment portfolio, respectively, was rated AA-, Aa3 and higher by nationally recognized statistical rating organizations. All fixed income securities were rated as investment grade as of September 30, 2013 and December 31, 2012.

Ecova reviews its investments continuously for indicators of other-than-temporary impairment. To make this determination, Ecova employs a methodology that considers available quantitative and qualitative evidence in evaluating potential impairment of its investments. If the cost of an investment exceeds its fair value, Ecova evaluates, among other factors, general market conditions, credit quality of instrument issuers, the length of time and extent to which the fair value is less than cost, and whether it has plans to sell the security or it is more-likely-than not that Ecova will be required to sell the security before recovery. Ecova also considers 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 is determined to be other-than-temporary, an impairment charge is recorded in earnings and a new cost basis in the investment is established. Based on Ecova's analysis, securities available for sale do not meet the criteria for other-than-temporary impairment as of September 30, 2013 or December 31, 2012.

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,	
	2013	2012	2013	2012
Proceeds from sales, maturities and calls	$ 1,825	$ 32,053	$ 16,955	$ 103,545
Gross realized gains	2	111	20	252
Gross realized losses	—	—	—	—

Contractual maturities of securities available for sale as of September 30, 2013 and December 31, 2012 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
September 30, 2013	$ 5,655	$ 18,479	$ 48,437	$ 2,906	$ 75,477
December 31, 2012	3,047	11,786	41,485	3,003	59,321

Actual maturities may differ due to call or prepayment rights and the effective maturity was 3.1 years as of September 30, 2013 and 1.9 years as of December 31, 2012.

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 discounted cash flow model 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, 2012 for Ecova and as of November 30, 2012 for the other businesses and determined that goodwill was not impaired at that time.

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

	Ecova	Other	Accumulated Impairment Losses	Total
Balance as of December 31, 2012	$ 70,713	$ 12,979	$ (7,733)	$ 75,959
Adjustments	803	—	—	803
Balance as of September 30, 2013	$ 71,516	$ 12,979	$ (7,733)	$ 76,762

Accumulated impairment losses are attributable to the other businesses. The adjustment to goodwill recorded represents a purchase accounting adjustment for Ecova's acquisition of LPB based upon final review of the fair market value of the noncontrolling interests associated with a portion of the LPB business and based on review of the fair market value of the client relationship intangible asset.

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,	
	2013	2012	2013	2012
Intangible asset amortization	$ 2,765	$ 2,436	$ 8,442	$ 7,091

The following table details the estimated amortization expense related to Intangible Assets for each of the five years ending December 31 (dollars in thousands):

	Remaining 2013	2014	2015	2016	2017
Estimated amortization expense	$ 2,292	$ 10,460	$ 8,484	$ 7,359	$ 6,516

The gross carrying amount and accumulated amortization of Intangible Assets as of September 30, 2013 and December 31, 2012 are as follows (dollars in thousands):

	Estimated Useful Lives	September 30, 2013	December 31, 2012
Client backlog and relationships	2 - 12 years	$ 33,559	$ 32,059
Software development costs	3 - 7 years	38,148	33,990
Other	1 - 10 years	3,332	6,237
Total intangible assets		75,039	72,286
Client relationships accumulated amortization		(11,255)	(7,793)
Software development costs accumulated amortization		(20,383)	(16,557)
Other accumulated amortization		(2,248)	(1,680)
Total accumulated amortization		(33,886)	(26,030)
Total intangible assets - net		$ 41,153	$ 46,256

Of the total net intangible assets above, intangible assets associated with Ecova represent approximately $40.4 million and $45.4 million at September 30, 2013 and December 31, 2012, respectively.

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 any particular derivative depends on the intended use of that derivative and the resulting designation.

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

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

Fair Value Measurements

Fair value represents the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Energy commodity derivative assets and liabilities, investments and funds held for clients, deferred compensation assets, as well as derivatives related to interest rate swap agreements and foreign currency exchange contracts, are reported at estimated fair value on the Condensed Consolidated Balance Sheets. See Note 9 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.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax, consisted of the following as of September 30, 2013 and December 31, 2012 (dollars in thousands):

	September 30, 2013	December 31, 2012
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $(3,401) and $(3,698), respectively	$ (6,316)	$ (6,867)
Unrealized gain (loss) on securities available for sale - net of taxes of $(904) and $97, respectively	(1,532)	167
Total accumulated other comprehensive loss	$ (7,848)	$ (6,700)

The following table details the reclassifications out of accumulated other comprehensive loss by component for the three and nine months ended September 30, 2013 (dollars in thousands):

	Amounts Reclassified from Accumulated Other Comprehensive Loss		
Details about Accumulated Other Comprehensive Loss Components	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013	Affected Line Item in Statement of Income
Realized gains on investment securities	$ 2	$ 20	Other income-net
	2	20	Total before tax
	(1)	(8)	Tax expense
	$ 1	$ 12	Net of tax
Amortization of defined benefit pension items			
Amortization of net loss	$ (4,891)	$ (14,673)	(a)
Adjustment due to effects of regulation	4,608	13,825	(a)
	(283)	(848)	Total before tax
	99	297	Tax benefit
	$ (184)	$ (551)	Net of tax

(a) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 6 for additional details).

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.

Voluntary Severance Incentive Program

At December 31, 2012, the Company accrued total severance costs of $7.3 million (pre-tax) related to the voluntary termination of 55 employees. The total severance costs were made up of the severance payments and the related payroll taxes and employee benefit costs. All terminations under the voluntary severance incentive program were completed by December 31, 2012. The cost of the program was recognized as expense during the fourth quarter of 2012 and severance pay was distributed in a single lump sum cash payment to each participant during January 2013. As of September 30, 2013, there was no remaining liability accrued.

Correction of an Immaterial Error

Subsequent to the issuance of the Company's condensed consolidated financial statements for the three and nine months ended September 30, 2012, the Company's management identified certain employee-related operating expenses, dues and donations, and other operating expenses totaling $3.4 million and $8.0 million for the three and nine months ended September 30, 2012, respectively, which had been erroneously included in “Other expense-net” in the previously issued financial statements rather than as a reduction to “Income from operations.” Accordingly, such classification has been corrected in the accompanying Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2012 by including $2.0 million and $5.4 million of other operating expenses within utility operating expense, $1.4 million and $2.5 million of other operating expenses within other non-utility operating expenses and $0.03 million and $0.1 million of taxes other than income taxes within utility operating expenses, respectively. Such items had no effect on net income or earnings per share.

Reclassifications

Certain prior year amounts on the Company's Condensed Consolidated Statements of Income and Condensed Consolidated Statements of Cash Flows have been reclassified to conform to the current year presentation. In the current year Condensed Consolidated Statements of Income, Ecova operating revenues and operating expenses have been reclassified to separate line items. Previously, such amounts had been classified within the line items captioned "Other non-utility revenues" and “Other non-utility operating expenses,” respectively. Such items had no effect on net income or earnings per share. In the current year Condensed Consolidated Statements of Cash Flows, "Amortization of investment in exchange power," "Stock-based compensation expense," "Pension and other postretirement benefit expense" and "Amortization of Spokane Energy contract" have been added as their own line items. These were previously included in "Other" in the operating activities section.

NOTE 2. NEW ACCOUNTING STANDARDS

In February 2013, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2013-02, “Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income.” This ASU does not change current requirements for reporting net income or other comprehensive income in financial statements; however, it requires entities to disclose the effect on the line items of net income for reclassifications out of accumulated other comprehensive income if the item being reclassified is required to be reclassified in its entirety to net income under U.S. GAAP. For other items that are not required to be reclassified in their entirety to net income under U.S. GAAP, an entity is required to cross-reference other disclosures required under U.S. GAAP to provide additional detail about those items. The Company adopted this ASU effective January 1, 2013. The adoption of this ASU required additional disclosures in the Company's financial statements; however, it did not have any impact on the Company's financial condition, results of operations and cash flows.

In December 2011, the FASB issued ASU No. 2011-11, “Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities.” This ASU enhances disclosure requirements about the nature of an entity's right to offset and related arrangements associated with its financial instruments and derivative instruments. ASU No. 2011-11 requires the disclosure of the gross amounts subject to rights of set off, amounts offset in accordance with the accounting standards followed, and the related net exposure. The Company adopted this ASU effective January 1, 2013. The adoption of this ASU required additional disclosures in the Company's financial statements; however, it did not have any impact on the Company's financial condition, results of operations and cash flows.

In January 2013, the FASB issued ASU No. 2013-01, “Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities.” This ASU clarifies which instruments and transactions are subject to the enhanced disclosure requirements of ASU 2011-11 regarding the offsetting of financial assets and liabilities. ASU No. 2013-01 limits the scope of ASU No. 2011-11 to only recognized derivative instruments, repurchase agreements and reverse repurchase agreements, and borrowing and lending securities transactions that are offset in accordance with either Accounting Standards Codification (ASC) 210-20-45 or ASC 815-10-45. The Company adopted this ASU effective January 1, 2013. The adoption of this ASU did not have any impact on the Company's financial condition, results of operations and cash flows.

NOTE 3. VARIABLE INTEREST ENTITIES

Lancaster Power Purchase Agreement

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

Avista Corp. has a variable interest in the PPA. Accordingly, Avista Corp. made an evaluation of which interest holders have the power to direct the activities that most significantly impact the economic performance of the entity and which interest holders have the obligation to absorb losses or receive benefits that could be significant to the entity. Avista Corp. pays a fixed capacity and operations and maintenance payment and certain monthly variable costs under the PPA. Under the terms of the PPA, Avista Corp. makes the dispatch decisions, provides all natural gas fuel and receives all of the electric energy output from the Lancaster Plant. However, Rathdrum Power LLC (the owner) controls the daily operation of the Lancaster Plant and makes operating and maintenance decisions. Rathdrum Power LLC controls all of the rights and obligations of the Lancaster Plant after the expiration of the PPA in 2026. It is estimated that the plant will have 15 to 25 years of useful life after that time. Rathdrum Power LLC bears the maintenance risk of the plant and will receive the residual value of the Lancaster Plant. Avista Corp. has no debt or equity investments in the Lancaster Plant and does not provide financial support through liquidity arrangements or other commitments (other than the PPA). Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Lancaster Plant. Accordingly, neither the Lancaster Plant nor Rathdrum Power LLC is included in Avista Corp.’s condensed consolidated financial statements. The Company has a future contractual obligation of approximately $303 million under the PPA (representing the fixed capacity and operations and maintenance payments through 2026) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

Palouse Wind Power Purchase Agreement

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

The Company evaluated this agreement to determine if it has a variable interest which must be consolidated. Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Palouse Wind facility due to the fact that it pays a fixed price per MWh, which represents the only financial obligation, and does not have any input into the management of the day-to-day operations of the facility. Accordingly, Palouse Wind is not included in Avista Corp.'s condensed consolidated financial statements. The Company has a future contractual obligation of approximately $562 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. REDEEMABLE NONCONTROLLING INTERESTS AND SUBSIDIARY ACQUISITIONS

Certain minority shareholders and option holders of Ecova have the right to put their shares back to Ecova at their discretion during an annual put window which is in March of each year. Stock options and other outstanding redeemable stock are valued at their maximum redemption amount which is equal to their intrinsic value (fair value less exercise price).

The following details redeemable noncontrolling interests as of September 30, 2013 and December 31, 2012 (dollars in thousands):

	September 30, 2013	December 31, 2012
Stock options and other outstanding redeemable stock	$ 8,330	$ 4,938

On January 31, 2012, Ecova acquired all of the capital stock of LPB Energy Management (LPB), a Dallas, Texas-based energy management company. The cash paid for the acquisition of LPB of $50.6 million was funded by Ecova through $25.0 million of borrowings under its committed credit agreement, a $20.0 million equity infusion from existing shareholders (including Avista Capital and the other owners of Ecova), and available cash. The acquired assets and assumed liabilities of LPB were recorded at their respective estimated fair values as of the date of acquisition. The results of operations of LPB are included in the condensed consolidated financial statements beginning February 1, 2012. The sellers of LPB did not receive additional purchase price payments in 2012 and will not receive additional payments in 2013; however, they have the potential to receive additional purchase price payments of $1.5 million in 2014. These payments are contingent upon reaching certain revenue thresholds for certain customer contracts. As of September 30, 2013, Ecova has recorded a contingent liability of $0.2 million based on management's assessment of the probability of the revenue thresholds being achieved.

Pro forma disclosures reflecting the effects of Ecova's acquisition are not presented, as the acquisition is not material to Avista Corp.'s condensed consolidated financial condition or results of operations.

NOTE 5. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

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

As part of our resource procurement and management operations in the electric business, we engage in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve our load obligations and the use of these resources to capture available economic value. We transact 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 our 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, we make 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 our 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 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, 2013 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 MWH	Financial MWH	Physical mmBTUs	Financial mmBTUs
2013	385	997	11,576	36,932	230	1,123	906	26,934
2014	702	1,942	22,613	115,004	345	2,839	1,786	84,108
2015	379	1,013	4,523	72,320	254	2,542	—	46,840
2016	367	—	2,505	38,210	287	1,634	—	13,380
2017	366	—	675	—	286	—	—	—
Thereafter	583	—	—	—	443	—	—	—

(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 above electric and natural gas derivative contracts 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, 2013 and December 31, 2012 (dollars in thousands):

	September 30, 2013	December 31, 2012
Number of contracts	14	20
Notional amount (in United States dollars)	$ 1,852	$ 12,621
Notional amount (in Canadian dollars)	1,929	12,502

Interest Rate Swap Agreements

Avista Corp. 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 swap 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, 2013 and December 31, 2012 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
September 30, 2013	2	$ 50,000	October 2014
	2	45,000	October 2015
	1	20,000	October 2016
	2	50,000	June 2018
December 31, 2012	2	85,000	June 2013
	2	50,000	October 2014
	1	25,000	October 2015

In June 2013, the Company cash settled two interest rate swap contracts (notional amount of $85.0 million) and received a total of $2.9 million. The interest rate swap contracts were settled in connection with the pricing of $90.0 million of First Mortgage Bonds that were issued in August 2013 (see Note 8). Upon settlement of interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the term of the associated debt.

Derivative Instruments Summary

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of September 30, 2013 (in thousands):

		Fair Value						
Derivative	Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet	Gross Assets Not Offset	Gross Liabilities Not Offset	Net Asset (Liability)
Foreign currency contracts	Other current assets	$ 19	$ (1)	$ —	$ 18	$ —	$ —	$ 18
Interest rate contracts	Other non-current liabilities and deferred credits	—	(471)	—	(471)	—	—	(471)
Interest rate contracts	Other property and investments - net	25,178	—	—	25,178	—	—	25,178
Commodity contracts (1)	Current utility energy commodity derivative assets	4,078	(648)	—	3,430	—	—	3,430
Commodity contracts (1)	Non-current utility energy commodity derivative assets	7,191	(6,898)	—	293	—	—	293
Commodity contracts (1)	Current utility energy commodity derivative liabilities	34,858	(58,687)	5,121	(18,708)	—	—	(18,708)
Commodity contracts (1)	Other non-current liabilities and deferred credits	23,274	(48,296)	5,292	(19,730)	—	—	(19,730)
Total derivative instruments recorded on the balance sheet		$ 94,598	$ (115,001)	$ 10,413	$ (9,990)	$ —	$ —	$ (9,990)

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of December 31, 2012 (in thousands):

		Fair Value						
Derivative	Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet	Gross Assets Not Offset	Gross Liabilities Not Offset	Net Asset (Liability)
Foreign currency contracts	Other current liabilities	$ 7	$ (34)	$ —	$ (27)	$ —	$ —	$ (27)
Interest rate contracts	Other current liabilities	—	(1,406)	—	(1,406)	—	—	(1,406)
Interest rate contracts	Other property and investments - net	7,265	—	—	7,265	—	—	7,265
Commodity contracts (1)	Current utility energy commodity derivative assets	10,772	(6,633)	—	4,139	(9,678)	6,572	1,033
Commodity contracts (1)	Non-current utility energy commodity derivative assets	18,779	(17,686)	—	1,093	—	—	1,093
Commodity contracts (1)	Current utility energy commodity derivative liabilities	50,227	(89,449)	9,707	(29,515)	9,678	(6,572)	(26,409)
Commodity contracts (1)	Other non-current liabilities and deferred credits	2,247	(28,558)	—	(26,311)	—	—	(26,311)
Total derivative instruments recorded on the balance sheet		$ 89,297	$ (143,766)	$ 9,707	$ (44,762)	$ —	$ —	$ (44,762)

(1) Avista Corp. has a master netting agreement that governs the transactions of multiple affiliated legal entities under this single master netting agreement. This master netting agreement allows 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. performs 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. does not perform cross-affiliate netting because the Company believes that cross-affiliate netting may not be enforceable. Therefore, the requirements for cross-affiliate netting under ASC 210-20-45 are not applicable for Avista Corp. As of September 30, 2013, all derivatives for each affiliated entity under this master netting agreement were in a net liability position. As such, there is no additional netting which requires disclosure.

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, 2013, the Company had cash deposited as collateral of $23.8 million and letters of credit of $20.1 million outstanding related to its energy derivative contracts. The Condensed Consolidated Balance Sheet at September 30, 2013 reflects the offsetting of $10.4 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, 2013 was $23.3 million. If the credit-risk-related contingent features underlying these agreements were triggered on September 30, 2013, the Company could be required to post $18.5 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.

We enter into bilateral transactions between Avista and various counterparties. We also trade energy and related derivative instruments through clearinghouse exchanges.

The Company seeks to mitigate bilateral credit risk by:

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

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

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

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

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

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

NOTE 6. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The 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 $44.0 million in cash to the pension plan for the nine months ended September 30, 2013. No further contributions are expected for the remainder of 2013. The Company contributed $44 million in cash to the pension plan in 2012.

In October 2013, the Company revised its defined benefit pension plan such that as of January 1, 2014 the plan will be closed to all non-union employees hired or rehired by the Company on or after January 1, 2014. All actively employed non-union employees that were hired prior to January 1, 2014 and 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 the company 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 the Company matches a portion of the pay deferred by each participant. In addition to the above changes, the Company has also revised its lump sum calculation for non-union participants who retire under the defined benefit pension plan to provide non-union retirees on or after January 1, 2014 with a lump sum amount equivalent to the present value of the annuity based upon applicable discount rates.

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

The Company provides certain health care and life insurance benefits for substantially all of its retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. In October 2013, the Company revised the health care benefit plan such that beginning on January 1, 2020, the method for calculating health insurance premiums for non-union retirees under age 65 and active Company employees 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 the Company will no longer provide a contribution towards his or her medical premiums. The Company will provide access to its 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.

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 for those who became executive officers on or before December 31, 2007. 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	
	2013	2012	2013	2012
Three months ended September 30:				
Service cost	$ 4,743	$ 3,891	$ 971	$ 689
Interest cost	5,978	6,084	1,373	1,256
Expected return on plan assets	(6,900)	(5,950)	(402)	(375)
Transition obligation recognition	—	—	—	125
Amortization of prior service cost	75	75	(37)	(37)
Net loss recognition	3,220	3,019	1,395	1,250
Net periodic benefit cost	$ 7,116	$ 7,119	$ 3,300	$ 2,908
Nine months ended September 30:				
Service cost	$ 14,229	$ 11,573	$ 3,035	$ 2,067
Interest cost	17,934	18,277	4,153	3,793
Expected return on plan assets	(20,700)	(17,900)	(1,202)	(1,125)
Transition obligation recognition	—	—	—	375
Amortization of prior service cost	225	225	(111)	(111)
Net loss recognition	9,989	8,797	4,342	3,814
Net periodic benefit cost	$ 21,677	$ 20,972	$ 10,217	$ 8,813

NOTE 7. COMMITTED LINES OF CREDIT

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400 million with an expiration date of February 2017. 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, 2013, the Company was in compliance with this covenant.

Balances outstanding and interest rates of borrowings under the Company’s revolving committed line of credit were as follows as of September 30, 2013 and December 31, 2012 (dollars in thousands):

	September 30, 2013	December 31, 2012
Borrowings outstanding at end of period	$ 66,000	$ 52,000
Letters of credit outstanding at end of period	$ 27,994	$ 35,885
Average interest rate on borrowings at end of period	1.10%	1.12%

As of September 30, 2013 the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Condensed Consolidated Balance Sheet.

Ecova

Ecova has a $125.0 million committed line of credit agreement with various financial institutions that has an expiration date of July 2017. The credit agreement is secured by all of Ecova's assets excluding investments and funds held for clients.

The committed line of credit agreement contains customary covenants and default provisions, including a covenant which requires that Ecova's “Consolidated Total Funded Debt to EBITDA Ratio” (as defined in the credit agreement) must be 2.50 to 1.00 or less, with provisions in the credit agreement allowing for a temporary increase of this ratio if a qualified acquisition is consummated by Ecova. In addition, Ecova's “Consolidated Fixed Charge Coverage Ratio” (as defined in the credit agreement) must be greater than 1.50 to 1.00 as of the last day of any fiscal quarter. As of September 30, 2013, Ecova was in compliance with these covenants.

Balances outstanding and interest rates of borrowings under Ecova's credit agreements were as follows as of September 30, 2013 and December 31, 2012 (dollars in thousands):

	September 30, 2013	December 31, 2012
Borrowings outstanding at end of period	$ 50,000	$ 54,000
Average interest rate on borrowings at end of period	2.19%	2.21%

As of September 30, 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 8. LONG-TERM DEBT

The following details long-term debt outstanding as of September 30, 2013 and December 31, 2012 (dollars in thousands):

Maturity Year	Description	Interest Rate	September 30, 2013	December 31, 2012
2013	First Mortgage Bonds	1.68%	$ 50,000	$ 50,000
2016	First Mortgage Bonds	0.84%	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 (2)	(2)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2047	First Mortgage Bonds	4.23%	80,000	80,000
	Total secured long-term debt		1,426,700	1,336,700
	Other long-term debt and capital leases		4,680	5,092
	Settled interest rate swaps (3)		(23,760)	(27,900)
	Unamortized debt discount		(1,330)	(1,453)
	Total		1,406,290	1,312,439
	Secured Pollution Control Bonds held by Avista Corporation (1) (2)		(83,700)	(83,700)
	Current portion of long-term debt		(50,330)	(50,372)
	Total long-term debt		$ 1,272,260	$ 1,178,367

(1) In December 2010, $66.7 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due 2032, which had been held by Avista Corp. since 2008, were refunded by a new bond issue (Series 2010A). 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 Sheet.

(2) In December 2010, $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds, (Avista Corporation Colstrip Project) due 2034, which had been held by Avista Corp. since 2009, were refunded by a new bond issue (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, the 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 Sheet.

(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 August 2013, Avista Corp. entered into a $90.0 million term loan agreement with an institutional investor that bears an annual interest rate of 0.84 percent and matures in 2016. The term loan agreement is secured by non-transferable First Mortgage Bonds of the Company issued to the agent bank that will only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the term loan agreement. The net proceeds from the $90.0 million term loan agreement were used to repay a portion of corporate indebtedness in anticipation of $50.0 million in First Mortgage Bonds maturing in December 2013.

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.

NOTE 9. FAIR VALUE

The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable and short-term borrowings are reasonable estimates of their fair values. Long-term debt (including current portion, but excluding capital leases), nonrecourse long-term debt and long-term debt to affiliated trusts are reported at carrying value on the Condensed Consolidated Balance Sheets.

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

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

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

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

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

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

The following table sets forth the carrying value and estimated fair value of the Company’s financial instruments not reported at estimated fair value on the Condensed Consolidated Balance Sheets as of September 30, 2013 and December 31, 2012 (dollars in thousands):

	September 30, 2013		December 31, 2012	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 951,000	$ 1,083,214	$ 951,000	$ 1,164,639
Long-term debt (Level 3)	392,000	382,426	302,000	320,892
Nonrecourse long-term debt (Level 3)	21,688	22,875	32,803	35,297
Long-term debt to affiliated trusts (Level 3)	51,547	36,861	51,547	43,686

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

The following table discloses by level within the fair value hierarchy the Company’s assets and liabilities measured and reported on the Condensed Consolidated Balance Sheets as of September 30, 2013 and December 31, 2012 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, 2013					
Assets:					
Energy commodity derivatives	$ —	$ 69,334	$ —	$ (65,611)	$ 3,723
Level 3 energy commodity derivatives:					
Power exchange agreement	—	—	67	(67)	—
Foreign currency derivatives	—	19	—	—	19
Interest rate swaps	—	25,178	—	—	25,178
Investments and funds held for clients:					
Money market funds	3,238	—	—	—	3,238
Securities available for sale:					
U.S. government agency	—	66,165	—	—	66,165
Municipal	—	3,542	—	—	3,542
Corporate fixed income – financial	—	3,004	—	—	3,004
Corporate fixed income – industrial	—	1,766	—	—	1,766
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)	1,829	—	—	—	1,829
Equity securities (2)	6,213	—	—	—	6,213
Total	$ 12,880	$ 170,008	$ 67	$ (65,678)	$ 117,277
Liabilities:					
Energy commodity derivatives	$ —	$ 96,464	$ —	$ (76,024)	$ 20,440
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	1,193	—	1,193
Power exchange agreement	—	—	16,111	(67)	16,044
Power option agreement	—	—	761	—	761
Foreign currency derivatives	—	1	—	—	1
Interest rate swaps	—	471	—	—	471
Total	$ —	$ 96,936	$ 18,065	$ (76,091)	$ 38,910

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2012					
Assets:					
Energy commodity derivatives	$ —	$ 81,640	$ —	$ (76,408)	$ 5,232
Level 3 energy commodity derivatives:					
Power exchange agreement	—	—	385	(385)	—
Foreign currency derivatives	—	7	—	(7)	—
Interest rate swaps	—	7,265	—	—	7,265
Investments and funds held for clients:					
Money market funds	15,084	—	—	—	15,084
Securities available for sale:					
U.S. government agency	—	48,496	—	—	48,496
Municipal	—	848	—	—	848
Corporate fixed income – financial	—	5,026	—	—	5,026
Corporate fixed income – industrial	—	3,936	—	—	3,936
Certificate of deposits	—	1,015	—	—	1,015
Funds held in trust account of Spokane Energy	1,600	—	—	—	1,600
Deferred compensation assets:					
Fixed income securities (2)	2,010	—	—	—	2,010
Equity securities (2)	5,955	—	—	—	5,955
Total	$ 24,649	$ 148,233	$ 385	$ (76,800)	$ 96,467
Liabilities:					
Energy commodity derivatives	$ —	$ 119,390	$ —	$ (86,115)	$ 33,275
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	2,379	—	2,379
Power exchange agreement	—	—	19,077	(385)	18,692
Power option agreement	—	—	1,480	—	1,480
Foreign currency derivatives	—	34	—	(7)	27
Interest rate swaps	—	1,406	—	—	1,406
Total	$ —	$ 120,830	$ 22,936	$ (86,507)	$ 57,259

(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.

For securities available for sale (held at Ecova) Ecova uses a nationally recognized third party to obtain fair value and reviews these prices for accuracy using a variety of market tools and analysis. Ecova's pricing vendor uses a generic model which uses standard inputs, including (listed in order of priority for use) benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, market bids/offers and other reference data. The pricing vendor also monitors market indicators, as well as industry and economic events. All securities available for sale were deemed Level 2.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.8 million as of September 30, 2013 and December 31, 2012.

Level 3 Fair Value

For the power exchange agreement, the Company compares the Level 2 brokered quotes and forward price curves described above to an internally developed forward price which is based on the average operating and maintenance (O&M) charges from four surrogate nuclear power plants around the country for the current year. Because the nuclear power plant O&M charges are only known for one year, all forward years are estimated assuming an annual escalation. In addition to the forward price being estimated using unobservable inputs, the Company also estimates the volumes of the transactions that will take place in the future based on historical average transaction volumes per delivery year (November to April). Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, a change in the current year O&M charges for the surrogate plants is accompanied by a directionally similar change in O&M charges in future years. There is generally not a correlation between external market prices and the O&M charges used to develop the internal forward price.

For the power commodity option agreement, the Company uses the Black-Scholes-Merton valuation model to estimate the fair value, and this model includes significant inputs not observable or corroborated in the market. These inputs include 1) the strike price (which is an internally derived price based on a combination of generation plant heat rate factors, natural gas market pricing, delivery and other O&M charges, 2) estimated delivery volumes for years beyond 2013, and 3) volatility rates for periods beyond October 2016. 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 sales volumes (within contractual limits) as well as the timing of those transactions. Changing the timing of volume estimates changes the timing of 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. As of September 30, 2013, all contractual purchases have been made by Avista Corp. under the natural gas commodity exchange agreement; therefore, the Company no longer estimates forward purchase volumes and forward purchase prices as these are not significant inputs to the calculation.

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, 2013 (dollars in thousands):

	Fair Value (Net) at September 30, 2013	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (16,044)	Surrogate facility pricing	O&M charges	$30.18-$53.90/MWh (1)
			Escalation factor	3% - 2014 to 2019
			Transaction volumes	365,619 - 394,255 MWhs
Power option agreement	(761)	Black-Scholes-Merton	Strike price	$55.53/MWh - 2015
				$69.60/MWh - 2019
			Delivery volumes	157,517 - 287,147 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreement	(1,193)	Internally derived weighted average cost of gas	Forward purchase prices	(3)
			Forward sales prices	$3.64 - $4.19/mmBTU
			Purchase volumes	(3)
			Sales volumes	139,980 - 310,000 mmBTUs

(1) The average O&M charges for 2013 were $40.93 per MWh.

(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.32 for 2013 to 0.21 in October 2016.

(3) As of September 30, 2013, all contractual purchases have been made by Avista Corp. under the natural gas exchange agreement; therefore, the Company no longer estimates forward purchase volumes and forward purchase prices as these are not significant inputs to the calculation.

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, the significant inputs, and the 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, 2013 and 2012 (dollars in thousands):

	Natural Gas Exchange Agreement	Power Exchange Agreement	Power Option Agreement	Total
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)

	Natural Gas Exchange Agreement	Power Exchange Agreement	Power Option Agreement	Total
Three months ended September 30, 2012:				
Balance as of July 1, 2012	$ (2,727)	$ (10,438)	$ (1,756)	$ (14,921)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	(377)	(7,438)	171	(7,644)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(1)	—	—	(1)
Transfers to/from other categories	—	—	—	—
Ending balance as of September 30, 2012	$ (3,105)	$ (17,876)	$ (1,585)	$ (22,566)
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 to/from other categories	—	—	—	—
Ending balance as of September 30, 2013	$ (1,193)	$ (16,044)	$ (761)	$ (17,998)
Nine months ended September 30, 2012:				
Balance as of January 1, 2012	$ (1,688)	$ (9,910)	$ (1,260)	$ (12,858)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	(364)	(12,216)	(325)	(12,905)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(1,053)	4,250	—	3,197
Transfers from other categories	—	—	—	—
Ending balance as of September 30, 2012	$ (3,105)	$ (17,876)	$ (1,585)	$ (22,566)

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

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

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corporation 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,	
	2013	2012	2013	2012
Numerator:				
Net income attributable to Avista Corporation shareholders	$ 11,413	$ 5,786	$ 79,411	$ 62,352
Subsidiary earnings adjustment for dilutive securities	(81)	(16)	(163)	(25)
Adjusted net income attributable to Avista Corporation shareholders for computation of diluted earnings per common share	$ 11,332	$ 5,770	$ 79,248	$ 62,327
Denominator:				
Weighted-average number of common shares outstanding-basic	59,994	59,047	59,933	58,778
Effect of dilutive securities:				
Performance and restricted stock awards	38	71	31	234
Stock options	—	5	—	14
Weighted-average number of common shares outstanding-diluted	60,032	59,123	59,964	59,026
Earnings per common share attributable to Avista Corporation shareholders:				
Basic	$ 0.19	$ 0.10	$ 1.32	$ 1.06
Diluted	$ 0.19	$ 0.10	$ 1.32	$ 1.06

There were no shares excluded from the calculation because they were antidilutive. All stock options had exercise prices which were less than the average market price of Avista Corp. common stock during the respective periods.

NOTE 11. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For all such matters, the Company intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista Utilities' 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) between Avista Corp. doing business as Avista Utilities, Avista Energy and the FERC's Trial Staff 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). Pending before the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) are petitions of the Attorney General of the State of California (California AG) and the California Electricity Oversight Board challenging FERC's decisions approving the Agreement in Resolution. 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 the short-term energy markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX) from May 1, 2000 to October 2, 2000 (Bidding Investigation). That matter is also pending before the Ninth Circuit, after the California AG, Pacific Gas & Electric (PG&E), Southern California Edison Company (SCE) and the California Public Utilities Commission (CPUC) filed petitions for review in 2005.

Based on the FERC's order approving the Agreement in Resolution in the Trading Investigation and order denying rehearing requests, the Company does not expect that this proceeding will have any material effect on its financial condition, results of operations or cash flows. Furthermore, based on information currently known to the Company regarding the Bidding Investigation and the fact that the FERC Staff did not find any evidence of manipulative behavior, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows.

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). Proposed refunds are based on the calculation of mitigated market clearing prices for each hour. The FERC ruled that if the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, sellers may document these costs and limit their refund liability commensurately. In September 2005, Avista Energy submitted its cost filing claim pursuant to the FERC's August 2005 order. The filing was initially accepted by the FERC, but in March 2011, the FERC ordered Avista Energy to remove any return on equity in a compliance filing with the CalISO, which Avista Energy did in April 2011. A challenge to Avista Energy's cost filing by the California AG, the CPUC, PG&E and SCE was denied in July 2011 as a collateral attack on the FERC's prior orders accepting Avista Energy's cost filing. In July 2011, the California AG, the CPUC, PG&E and SCE filed a petition for review of the FERC's orders regarding Avista Energy's cost filing with the Ninth Circuit.

The 2001 bankruptcy of PG&E resulted in a default on its payment obligations to the CalPX. As a result, Avista Energy has not been paid for all of its energy sales during the Refund Period. Those funds are now in escrow accounts and will not be released until the FERC issues an order directing such release in the California refund proceeding. As of September 30, 2013, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from the defaulting parties.

In August 2006, the Ninth Circuit upheld October 2, 2000 as the refund effective date for the FPA section 206 refund proceeding, but remanded to the FERC its decision not to consider an FPA section 309 remedy for tariff violations prior to that date. In an order issued in May 2011, the FERC clarified the issues set for hearing for the period May 1, 2000 - October 1, 2000 (Summer Period): (1) which market practices and behaviors constitute a violation of the then-current CalISO, CalPX, and individual seller's tariffs and FERC orders; (2) whether any of the sellers named as respondents in this proceeding engaged in those tariff violations; and (3) whether any such tariff violations affected the market clearing price. The FERC also gave the California Parties an opportunity to show that exchange transactions with the CalISO during the Refund Period were not just and reasonable. Avista Energy had one exchange transaction with the CalISO during the Refund Period. The California AG, the CPUC, PG&E and SCE filed for rehearing of the FERC's May 2011 order, arguing that it improperly denies them a market-wide remedy for the pre-refund period. That request for rehearing was denied in an order issued by the FERC on November 2, 2012. The California AG, the CPUC, PG&E and SCE filed a petition for review of the May 2011 and November 2012 orders with the Ninth Circuit on November 7, 2012.

A FERC hearing commenced on April 11, 2012 and concluded on July 19, 2012. On August 27, 2012, the Presiding Administrative Law Judge (ALJ) issued a partial initial decision granting Avista Utilities' motion for summary disposition, based on the stipulation by the California Parties that there are no allegations of tariff violations made against Avista Utilities in this proceeding and therefore no tariff violations by Avista Utilities that affected the market clearing price in any hour during the Summer Period. On November 2, 2012, the FERC issued an order affirming the partial initial decision and dismissing Avista Utilities from the proceeding, thereby terminating all claims against Avista Utilities for the Summer Period. In the same order, the FERC also held that a market-wide remedy would not be appropriate with regard to any respondent during the Summer Period. The FERC stated that it is clear that the Ninth Circuit did not mandate a specific remedy on remand and, instead, left it to the FERC's discretion to determine which remedy would be appropriate. On December 3, 2012, the California Parties filed a request for clarification and rehearing of the November 2, 2012 order. On February 15, 2013, the ALJ issued an initial decision finding that certain Respondents committed various tariff and other violations that affected the market clearing price in the California organized markets during the Summer Period. The tariff violations identified for Avista Energy are type II and III bidding violations; false export violations; and selling ancillary services without market-based rate authority. The initial decision did not discuss evidence offered by Avista Energy, on an hour-by-hour basis, rebutting the alleged violations. With respect to Avista Energy's one exchange transaction with the CalISO during the Refund Period, the judge made no findings with respect to the justness and reasonableness of that transaction, but nonetheless determined that Avista Energy owed approximately $0.2 million in refunds with regard to the transaction. Avista Energy filed its brief on exceptions to the initial decision on April 12, 2013. The California AG, the CPUC, PG&E and SCE filed a brief opposing exceptions on June 7, 2013.

Because the resolution of the California refund proceeding remains uncertain, legal counsel cannot express an opinion on the extent of the Company's liability, if any. However, based on information currently known, the Company does not expect that the refunds ultimately ordered for the Refund Period would result in a material loss. In the event that the Commission does not overturn the legal and factual errors in the February 15, 2013 initial decision, the Company does not expect that the refunds ultimately ordered for that period would result in a material loss either. This is primarily due to the fact that the FERC orders have stated that any refunds will be netted against unpaid amounts owed to the respective parties and the Company does not believe that refunds would exceed unpaid amounts owed to the Company.

Pacific Northwest Refund Proceeding

In July 2001, the FERC 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, in denying the request for refunds, had failed to take into account new evidence of market manipulation in the California energy market and its potential ties to the Pacific Northwest energy market 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 evidence. In addition, the Ninth Circuit concluded that the FERC abused its discretion in denying potential relief for transactions involving energy that was purchased by California Energy Resources Scheduling (CERS) in the Pacific Northwest and ultimately consumed in California. The Ninth Circuit expressly declined to direct the FERC to grant refunds. The Ninth Circuit denied petitions for rehearing by various parties, and remanded the case to the FERC in April 2009.

On October 3, 2011, the FERC issued an Order on Remand, finding that, in light of the Ninth Circuit's remand order, additional procedures are needed to address possible unlawful activity that may have influenced prices in the Pacific Northwest spot market during the period from December 25, 2000 through June 20, 2001. The Order on Remand establishes an evidentiary, trial-type hearing before an ALJ, and reopens the record to permit parties to present evidence of unlawful market activity. The Order on Remand also allows participants to supplement the record with additional evidence on CERS transactions in the Pacific Northwest spot market from January 18, 2001 to June 20, 2001. The Order on Remand states 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 will not be sufficient to establish a causal connection between a particular seller's alleged unlawful activities and the specific contract negotiations at issue.

On July 11, 2012, Avista Energy and Avista Utilities filed settlements of all issues in this docket with regard to the claims made by the City of Tacoma. On September 21, 2012, and September 26, 2012, the FERC issued orders approving the settlements between the City of Tacoma and Avista Utilities and Avista Energy, respectively, thus terminating those claims. The two remaining direct claimants against Avista Utilities and Avista Energy in this proceeding are the City of Seattle, Washington (Seattle), and the California Attorney General (on behalf of CERS).

On April 5, 2013, the FERC issued an Order on Rehearing of the October 3, 2011 Order on Remand. The Order on Rehearing reaffirmed the rulings in the Order on Remand about the scope of the hearing and permissible evidence, rejecting various challenges by the claimants. The Order on Rehearing expanded 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 hearing before an administrative law judge began on August 27, 2013, and concluded on October 24, 2013. The parties' initial post-hearing briefs are due on December 16, 2013, and their reply briefs are due on January 28, 2014. The ALJ's initial decision is anticipated on or before March 18, 2014.

On April 11, 2013, the California Parties filed a petition for review of the October 3, 2011 Order on Remand and the April 5, 2013 Order on Rehearing, in the Ninth Circuit. Seattle filed a petition for review of the same orders on April 26, 2013. On May 22, 2013, the Ninth Circuit issued an order consolidating the California Parties' and Seattle's petitions for review with respect to the Order on Remand and the Order on Rehearing.

Both Avista Utilities and Avista Energy were buyers and sellers of energy in the Pacific Northwest energy market during the period between January 1, 2000 and June 20, 2001, and are subject to potential claims in this proceeding. If refunds are ordered by the FERC with regard to any particular contract, Avista Utilities and Avista Energy could be liable to make payments. The Company cannot predict the outcome of this proceeding or the amount of any refunds that Avista Utilities or Avista Energy could be ordered to make. Therefore, the Company cannot predict the potential impact the outcome of this matter could ultimately have on the Company's results of operations, financial condition or cash flows.

California Attorney General Complaint (the "Lockyer Complaint")

In May 2002, the FERC conditionally 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 adoption and 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.

In March 2008, the FERC issued an order establishing a trial-type hearing to address "whether any individual public utility seller's violation of the FERC's market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period." Purchasers in the California markets were given the opportunity to present evidence that "any seller that violated the quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus cause its market-based rates to be unjust and unreasonable." In March 2010, the Presiding ALJ granted the motions for summary disposition and found that a hearing was "unnecessary" because the California AG, CPUC, PG&E and SCE "failed to apply the appropriate test to determine market power during the relevant time period." The judge determined that "[w]ithout a proper showing of market power, the California Parties failed to establish a prima facie case." In May 2011, the FERC affirmed "in all respects" the ALJ's decision. In June 2011, the California AG, CPUC, PG&E and SCE filed for rehearing of that order. Those rehearing requests were denied by the FERC on June 13, 2012. On June 20, 2012, the California AG, CPUC, PG&E and SCE filed a petition for review of the FERC's order with the Ninth Circuit.

Based on information currently known to the Company's management, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows.

Colstrip Generating Project - Complaint Alleging Water Pollution

In March 2007, two families that own property near the holding ponds from Units 3 & 4 of the Colstrip Generating Project (Colstrip) filed a complaint against the owners of Colstrip and Hydrometrics, Inc. in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs alleged that the holding ponds and remediation activities adversely impacted their property. They alleged contamination, decrease in water tables, reduced flow of streams on their property and other similar impacts to their property. They also sought punitive damages, attorneys' fees, an order by the court to remove certain ponds, and the forfeiture of profits earned from the generation of Colstrip. In September 2010, the owners of Colstrip filed a motion with the court to enforce a settlement agreement that would resolve all issues between the parties. In October 2011 the court issued an order which enforces the settlement agreement. The plaintiffs subsequently appealed the court's decision and, on December 31, 2012, the Montana Supreme Court issued its decision, holding that the District Court properly granted the motion to enforce the settlement agreement. A petition for rehearing before the Supreme Court was denied on February 5, 2013. A motion to dismiss the case was approved by the court. Under the settlement, Avista Corp.'s portion of payment (which was accrued in 2010) to the plaintiffs was not material to 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 (Complaint) in the United States District Court for the District of Montana, Billings Division, against the owners of the Colstrip Generating Project (Colstrip). Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The other Colstrip co-owners are PPL Montana, Puget Sound Energy, Portland General Electric Company, NorthWestern Energy and PacifiCorp. The Complaint alleges certain violations of the Clean Air Act, including the New Source Review, Title V and opacity requirements. The Plaintiffs request that the Court grant injunctive and declaratory relief, impose civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require payment of Plaintiffs' costs of litigation and attorney fees.

On May 3, 2013, the Colstrip owners and operator filed a partial motion to dismiss, seeking dismissal of 36 of the 39 claims. The Plaintiffs filed their opposition on May 31, 2013, and the owners and operator filed their reply on June 21, 2013. On July 17, 2013, the Court held a preliminary pretrial conference, and on July 18, 2013, the Court issued an Order establishing a procedural schedule and deadlines.

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. The Colstrip Owners and Operator Response is due on November 15, 2013.

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 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.

On October 11, 2013, the Colstrip owners and operator filed a motion to dismiss, seeking dismissal of all of Plaintiffs' claims contained in the Amended Complaint. Due to the preliminary nature of the lawsuit, Avista Corporation cannot, at this time, predict the outcome of the matter.

Spokane River Licensing

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

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

During 2013, through a collaborative process with key stakeholders, a decision was reached to not move forward with a specific capital project to add oxygen to Lake Spokane. At the time of such decision, the Company had expended $1.3 million on the discontinued project. On September 26, 2013 and October 23, 2013, the UTC and IPUC, respectively issued Orders approving the Company's petition for an accounting order authorizing deferral of costs related to the discontinued project. The Washington portion of the project costs were $0.9 million and this amount has been recorded as a regulatory asset until the next general rate case. The Idaho portion of the costs of $0.4 million will be recorded as a regulatory asset during the fourth quarter of 2013 and will be included in the next general rate case. The Company will address the prudence and recovery of these costs in the next Washington and Idaho general rate cases, expected to be filed in 2014.

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. Further evaluation and design improvements are underway prior to applying this approach to other spill gates. 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 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.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows. It is possible that a change could occur in the Company’s estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant.

NOTE 12. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. The Company's management evaluates performance based on income (loss) from operations before income taxes as well as net income (loss) attributable to Avista Corp. shareholders. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. Avista Utilities' business is managed based on the total regulated utility operation. Ecova is a provider of energy efficiency and other facility information and cost management programs and services for multi-site customers and utilities throughout North America. 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.

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

	Avista Utilities	Ecova	Other	Total Non-Utility	Intersegment Eliminations (1)	Total
For the three months ended September 30, 2013:						
Operating revenues	$ 278,923	$ 46,398	$ 11,004	$ 57,402	$ (450)	$ 335,875
Resource costs	131,136	—	—	—	—	131,136
Other operating expenses	69,596	37,047	10,662	47,709	(450)	116,855
Depreciation and amortization	29,823	3,909	171	4,080	—	33,903
Income from operations	29,657	5,442	170	5,612	—	35,269
Interest expense (2)	18,837	398	525	923	(77)	19,683
Income taxes	3,945	2,092	(578)	1,514	—	5,459
Net income (loss) attributable to Avista Corporation shareholders	9,447	3,040	(1,074)	1,966	—	11,413
Capital expenditures	75,368	357	24	381	—	75,749
For the three months ended September 30, 2012:						
Operating revenues	$ 292,535	$ 38,617	$ 9,930	$ 48,547	$ (450)	$ 340,632
Resource costs	153,801	—	—	—	—	153,801
Other operating expenses	66,456	33,868	10,581	44,449	(450)	110,455
Depreciation and amortization	28,255	3,260	131	3,391	—	31,646
Income from operations	25,901	1,489	(782)	707	—	26,608
Interest expense (2)	18,001	530	824	1,354	(91)	19,264
Income taxes	2,590	495	(1,477)	(982)	—	1,608
Net income (loss) attributable to Avista Corporation shareholders	7,660	640	(2,514)	(1,874)	—	5,786
Capital expenditures	57,964	1,023	619	1,642	—	59,606
For the nine months ended September 30, 2013:						
Operating revenues	$ 1,008,669	$ 133,365	$ 30,145	$ 163,510	$ (1,350)	$ 1,170,829
Resource costs	487,277	—	—	—	—	487,277
Other operating expenses	200,824	110,753	30,322	141,075	(1,350)	340,549
Depreciation and amortization	86,783	11,474	536	12,010	—	98,793
Income from operations	167,648	11,138	(713)	10,425	—	178,073
Interest expense (2)	56,635	1,265	1,801	3,066	(230)	59,471
Income taxes	43,278	4,178	(1,349)	2,829	—	46,107
Net income (loss) attributable to Avista Corporation shareholders	76,265	5,759	(2,613)	3,146	—	79,411
Capital expenditures	220,712	1,586	139	1,725	—	222,437
For the nine months ended September 30, 2012:						
Operating revenues	$ 992,210	$ 115,707	$ 29,907	$ 145,614	$ (1,350)	$ 1,136,474
Resource costs	500,805	—	—	—	—	500,805
Other operating expenses	196,759	104,392	29,830	134,222	(1,350)	329,631
Depreciation and amortization	83,327	9,455	511	9,966	—	93,293
Income from operations	147,596	1,860	(434)	1,426	—	149,022
Interest expense (2)	54,148	1,301	2,691	3,992	(274)	57,866
Income taxes	34,425	918	(2,237)	(1,319)	—	33,106
Net income (loss) attributable to Avista Corporation shareholders	65,157	962	(3,767)	(2,805)	—	62,352
Capital expenditures	178,440	3,248	660	3,908	—	182,348
Total Assets:						
As of September 30, 2013:	$ 3,961,718	$ 353,128	$ 87,156	$ 440,284	$ —	$ 4,402,002
As of December 31, 2012:	$ 3,894,821	$ 322,720	$ 95,638	$ 418,358	$ —	$ 4,313,179

(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 represent intercompany interest.

(2) Including interest expense to affiliated trusts.

NOTE 13. SUBSEQUENT EVENTS

On November 4, 2013, the Company entered into an agreement and plan of merger (Merger Agreement) with Alaska Energy and Resources Company (AERC), a privately-held company based in Juneau, Alaska. When the transaction is complete, AERC will become a wholly-owned subsidiary of Avista Corp.

The primary subsidiary of AERC is Alaska Electric Light & Power Company (AEL&P), the oldest regulated electric utility in Alaska. In 2012, AEL&P had annual revenues of $42 million and a total rate base of $111 million. AEL&P has 60 full-time employees and is the sole provider of electric services to approximately 15,900 customers in the city and borough of Juneau.

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

The merger consideration at closing will be $170 million, less AERC's indebtedness and subject to other customary closing adjustments (Merger Consideration). The transaction will be funded primarily through the issuance of Avista common stock to the shareholders of AERC. The transaction is expected to close by July 1, 2014, following the receipt of necessary regulatory approvals and the satisfaction of other closing conditions. Avista Corp. shareholder approval is not required.

Pursuant to the Merger Agreement, among other things, each of the issued and outstanding shares of AERC common stock (other than Dissenting Shares) will be converted into the right to receive consideration as follows:

i. the number of shares of Avista Corp. common stock equal to one share of AERC common stock multiplied by the Exchange Ratio; and

ii. a portion of the Representative Reimbursement Amount.

For purposes of the foregoing:

The ***Exchange Ratio*** is the ratio obtained by dividing the Per Share Amount by (i) $21.48 if the Avista Corp. Closing Price is less than or equal to $21.48, (ii) the Avista Corp. Closing Price, if the Avista Corp. Closing Price is greater than $21.48 and less than $34.30 or (iii) $34.30 if the Avista Corp. Closing Price is greater than or equal to $34.30.

The ***Per Share Amount*** is the amount determined by *dividing* (a) the Merger Consideration (as adjusted) *by* (b) the aggregate number of shares of AERC common stock outstanding immediately prior to the closing of the transaction.

The ***Representative Reimbursement Amount*** is a $500,000 cash payment to be made by Avista Corp. at the Closing to the Shareholders' Representative. The purpose of the Representative Reimbursement Amount is to reimburse the Shareholders' Representative for expenses incurred by the Shareholders' Representative in acting for the current shareholders of AERC in connection with the Merger. The total Merger Consideration will be reduced by the Representative Reimbursement Amount.

Dissenting Shares will not be converted into, or represent the right to receive, the Merger Consideration or any portion of the Representative Reimbursement Amount. Such shareholders will be entitled to receive payment of the fair value of Dissenting Shares held by them in accordance with the provisions of AS 10.06.580 of the Alaska Corporations Code. Any amounts paid to Dissenting Shares over the amounts otherwise payable in the form of Merger Consideration are indemnified expenses owed by AERC to Avista Corp.

The Merger Agreement has been approved by Avista Corp.'s and AERC's Boards of Directors, but the consummation of the transaction is subject to the satisfaction or waiver of specified closing conditions, including:

- the registration under the Securities Act of 1933 of the shares of common stock that will be issued to AERC shareholders;
- the approval of such shares for listing on the New York Stock Exchange;
- the approval of the merger transaction by the requisite number of AERC shareholders;
- the receipt of regulatory approvals and other consents required to consummate the merger transaction, including, among others, approvals from the FERC, the Regulatory Commission of Alaska, the UTC, the IPUC, the Public Utility Commission of Oregon (OPUC), the Public Service Commission of the State of Montana, the U.S. Federal Trade Commission (the FTC), the Antitrust Division of the U.S. Department of Justice (the DOJ) and any other applicable regulatory bodies on the terms and conditions specified in the definitive purchase agreement;
- the absence of the occurrence of a material adverse effect (as defined in the Merger Agreement) relating to either AERC or Avista Corp. after the date of the signed agreement; and
- other customary closing conditions.

The Merger Agreement also provides for customary termination rights for each of the Company and AERC, including the right for either party to terminate if the Merger has not been consummated by December 31, 2014; provided, however, that the failure of the Merger to have been consummated on or before December 31, 2014 was not caused by the failure of such party or any affiliate of such party to perform any of its obligations under the Merger Agreement. Upon termination of the Merger Agreement in accordance with its terms, there will be no further liability under the agreement except that nothing shall relieve any party thereto from liability for any breach of the agreement.

There may be certain commitments and contingencies that will be assumed when the merger transaction is consummated; however, Avista Corp. has not fully completed its evaluation of all the potential commitments and contingencies as of the date of this filing.

During the three and nine month periods ended September 30, 2013, Avista Corp. incurred $0.1 million (pre-tax) of transaction related fees which have been expensed and presented in the Condensed Consolidated Statements of Income in other operating expenses within other non-utility operating expenses. Avista Corp. expects to incur additional transaction related fees upon consummation of the transaction.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders 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, 2013, and the related condensed consolidated statements of income and of comprehensive income for the three-month and nine-month periods ended September 30, 2013 and 2012, and of equity and redeemable noncontrolling interests, and cash flows for the nine-month periods ended September 30, 2013 and 2012. 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, 2012, 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, 2013, 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, 2012 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 7, 2013

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

Business Segments

We have two reportable business segments as follows:

- **Avista Utilities** – an operating division of Avista Corp. that comprises our regulated utility operations. Avista Utilities generates, transmits and distributes electricity and distributes natural gas. The utility also engages in wholesale purchases and sales of electricity and natural gas.
- **Ecova** – an indirect subsidiary of Avista Corp. (78.9 percent owned as of September 30, 2013) provides energy efficiency and cost management programs and services for multi-site customers and utilities throughout North America. Ecova's service lines include expense management services for utility and telecom needs as well as strategic energy management and efficiency services that include procurement, conservation, performance reporting, financial planning, facility optimization and continuous monitoring, and energy efficiency program management for commercial enterprises and utilities.

We have other businesses, including sheet metal fabrication, venture fund investments and real estate investments, as well as certain other operations of Avista Capital. These activities do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp., including AM&D, doing business as METALfx.

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,	
	2013	2012	2013	2012
Avista Utilities	$ 9,447	$ 7,660	$ 76,265	$ 65,157
Ecova	3,040	640	5,759	962
Other	(1,074)	(2,514)	(2,613)	(3,767)
Net income attributable to Avista Corporation shareholders	$ 11,413	$ 5,786	$ 79,411	$ 62,352

Executive Level Summary

Overall

Net income attributable to Avista Corporation shareholders was $11.4 million for the three months ended September 30, 2013, an increase from $5.8 million for the three months ended September 30, 2012. This was due to an increase in earnings at Avista Utilities and Ecova and a decrease in losses at the other businesses. Earnings at Avista Utilities increased primarily due to the implementation of general rate increases in Washington and warmer weather that increased cooling loads, partially offset by expected increases in other operating expenses, depreciation and amortization, and taxes other than income taxes. Net income at Ecova increased due to increased revenue associated with expense and data management services, new services, and energy management services, partially offset by increases in other operating expenses and depreciation and amortization. These results, including a quantification of their respective impacts, are discussed in detail below.

Net income attributable to Avista Corporation shareholders was $79.4 million for the nine months ended September 30, 2013, an increase from $62.4 million for the nine months ended September 30, 2012. This was due to an increase in earnings at Avista Utilities and Ecova and a decrease in losses at the other businesses. Earnings at Avista Utilities increased primarily due to the implementation of general rate increases in Washington and the net benefit from the settlement with Bonneville Power Administration, partially offset by expected increases in other operating expenses, depreciation and amortization, and taxes other than income taxes. Net income at Ecova increased due to increased revenues associated with new services, expense and data management services, and energy management services. This was partially offset by higher other operating expenses and increased depreciation and amortization. These results, including a quantification of their respective impacts, are discussed in detail below.

Avista Utilities

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

- weather conditions,
- 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,
- the price of electricity in the wholesale market, including the effects of weather conditions, natural gas prices and other factors affecting supply and demand, and
- the reliability and availability of our generating resources.

In our utility operations, we regularly review the need for rate changes in each jurisdiction to improve the recovery of costs and capital investments in our generation, transmission and distribution systems. The following are the recent general rate increases that have occurred or will go into effect in the near future.

Jurisdiction	Service	Effective Date
Washington	Electric and Natural Gas	January 1, 2012
	Electric and Natural Gas	January 1, 2013 (1) (3)
	Electric and Natural Gas	January 1, 2014 (1) (3)
Idaho	Natural Gas	April 1, 2013 (2) (3)
	Electric and Natural Gas	October 1, 2013 (2) (3)
Oregon	Natural Gas	June 1, 2012

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

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

(3) Included in the original settlement agreements is a provision that we will not file a general rate case in these jurisdictions seeking new rates to take effect before January 1, 2015. We can, however, make a filing prior to January 1, 2015, but new rates resulting from the filing would not take effect prior to January 1, 2015. We currently intend to file a general rate case in each of these jurisdictions in early 2014 with proposed rates that would take effect on January 1, 2015. This provision does not preclude us from filing other rate adjustments such as Purchased Gas Adjustments.

In addition to the above, we filed a general rate case in Oregon in August 2013. The Public Utility Commission of Oregon (OPUC) has up to 10 months to review and issue a decision. See further discussion below under "Oregon General Rate Case."

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. Utility capital expenditures were $220.7 million for the nine months ended September 30, 2013. We expect utility capital expenditures to be about $280 million for 2013, $335 million for 2014, and $360 million for 2015. We increased our estimates for future capital expenditures from the previous estimates of $260 million annually in 2014 and 2015 to meet an increased demand for utility capital projects associated with updating and maintaining our generation, transmission and energy distribution systems to ensure reliability. These estimates of capital expenditures are subject to continuing review and adjustment (see discussion under “Avista Utilities Capital Expenditures”).

Customer Contract Renewal

An agreement with one of our largest electric customers, which consumes approximately 100 aMWs per year, expired on June 30, 2013. We negotiated a new agreement with this customer that became effective on July 1, 2013 which has a five-year term. A Joint Application requesting approval of the new agreement was approved by the IPUC on June 28, 2013. Under the new agreement, we expect a decrease in annual power sales to this customer of approximately $21 million and a resulting decrease in resource costs of approximately $19 million. According to the approved Joint Application, 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, will be tracked through the PCA in Idaho at 100 percent, so that we expect no impact on our earnings from the new agreement.

Colstrip Generating Facility Outage

We own a 15 percent interest in Units 3 and 4 of the Colstrip Generating Plant in southeastern Montana, a coal-fired facility which is operated by PPL Montana, LLC. On July 1, 2013, an unplanned outage occurred to Colstrip Unit 4, with identified damage to the stator and rotor assembly. Engineering estimates showed that the unit will be out of service for at least six months, and is not expected to be returned to service until the first quarter of 2014. The estimate for total repair costs is approximately $30 million, including labor costs, which will be shared proportionately among all the owners. While the split between capital and operating expense has not been fully determined, a portion of the repair costs will be capitalized. The plant operator carries property damage insurance coverage on behalf of the owners and has filed claims for potential insurance recovery of the repair work. There is a $2.5 million deductible for each event that is allocated proportionately among all the owners.

The lost generation of Colstrip Unit 4 will result in a combination of lower surplus wholesale sales and increased thermal fuel costs or purchased power costs to replace the energy, which will result in increased net power supply costs. Our estimates show an increase in power supply costs of approximately $12 million system-wide for 2013 as a result of the outage. All of the additional costs will be included in the ERM in Washington and the PCA in Idaho. After consideration of the impacts of the two recovery mechanisms and the sharing between us and our customers, the outage is estimated to have a negative impact on gross margin (operating revenues less resource costs) in the range of approximately $6 million to $7 million for 2013. In addition, there is a provision associated with the ERM that if the Colstrip Generating Plant drops below a 70 percent availability factor for the year, an automatic prudence review surrounding the cause of the outage and the costs to replace the lost power will be performed by the UTC. Also, actual fixed costs of the plant must be compared to authorized costs and if the fixed costs are below authorized costs, the difference is credited back to customers through the ERM.

Alaska Energy and Resources Company Planned Acquisition

On November 4, 2013, we entered into an agreement and plan of merger (Merger Agreement) with Alaska Energy and Resources Company (AERC), a privately-held company based in Juneau, Alaska. When the transaction is complete, AERC will become a wholly-owned subsidiary of Avista Corp.

The primary subsidiary of AERC is Alaska Electric Light & Power Company (AEL&P), the oldest regulated electric utility in Alaska. In 2012, AEL&P had annual revenues of $42 million and a total rate base of $111 million. AEL&P is the sole provider of electric services to approximately 15,900 customers in the city and borough of Juneau. The utility has a firm retail peak load of approximately 80 Megawatts (MW) and serves nearly 100 percent of its load with 102.7 MW of renewable hydroelectric generation capacity. The utility has 93.9 MW of diesel generating capacity to provide back-up service to all firm customers when necessary.

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

The merger consideration at closing will be $170 million, less AERC's indebtedness and subject to other customary closing adjustments. The transaction will be funded primarily through the issuance of Avista common stock to the shareholders of AERC. The transaction is expected to close by July 1, 2014, following the receipt of necessary regulatory approvals and the satisfaction of other closing conditions. Avista Corp. shareholder approval is not required. We expect that the addition of AERC will be slightly negative to earnings in 2014, and that it will contribute positively to earnings in 2015.

AEL&P currently has an authorized utility capital structure of 53.8 percent equity and an authorized return on equity of 12.875 percent. We expect that AEL&P will maintain this capital structure. The consolidated capital structure of AERC is expected to be similar to the capital structure of Avista Corp.

For additional information regarding the AERC transaction, including the valuation and number of shares of Avista common stock to be delivered to AERC shareholders, see “Note 13 of the Notes to Condensed Consolidated Financial Statements” and our Current Report on Form 8-K dated November 4, 2013.

Ecova

Ecova plans to continue to grow organically and possibly through strategic acquisitions. Ecova's acquisitions since 2008 have been funded through internally generated cash, borrowings under Ecova's credit facility and an equity infusion from existing shareholders. If Ecova's capital needs exceed its credit facility capacity or management determines a different capital structure is necessary, Ecova may require additional equity infusions from existing shareholders and/or new funding sources.

We may seek to monetize all or part of our investment in Ecova in the future. The value of a potential monetization depends on future market conditions, growth of the business and other factors. A strategic change to Ecova's ownership structure may provide access to public market capital and provide potential liquidity to Avista Corp. and the other owners of Ecova. There can be no assurance that such a transaction will be completed.

Liquidity and Capital Resources

We need to access long-term capital markets from time to time to finance capital expenditures, repay maturing long-term debt and obtain additional working capital. Our ability to access capital on reasonable terms is subject to numerous factors, many of which, including market conditions, are beyond our control. If we were unable to obtain capital on reasonable terms, it could limit or eliminate our ability to finance capital expenditures and repay maturing long-term debt. Our liquidity needs could exceed our short-term credit availability and lead to defaults on various financing arrangements. We would also likely be prohibited from paying dividends on our common stock.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400 million with an expiration date of February 2017. As of September 30, 2013, there were $66.0 million of cash borrowings and $28.0 million in letters of credit outstanding leaving $306.0 million of available liquidity under this line of credit.

Ecova has a $125.0 million committed line of credit agreement with various financial institutions that has an expiration date of July 2017. As of September 30, 2013, Ecova had $50.0 million of borrowings outstanding under its committed line of credit agreement. Based on certain covenant conditions contained in the credit agreement, at September 30, 2013, Ecova could borrow an additional $31.5 million and still be compliant with its covenants. The covenant restrictions are calculated on a rolling twelve month basis, so this additional borrowing capacity could increase or decrease or Ecova could be required to pay down the outstanding debt as future results change. See further discussion of the specific covenants below under "Ecova Credit Agreement."

There are $50.0 million in First Mortgage Bonds maturing in December 2013. In August 2013, we entered into a $90.0 million term loan agreement with an institutional investor bearing an annual interest rate of 0.84 percent and maturing in 2016.

We expect to issue up to $190 million of long-term debt during 2014, including up to $90 million of debt issuances associated with rebalancing the consolidated capital structure at AERC. This amount assumes we are going to refinance the existing net debt outstanding at AEL&P, the primary subsidiary of AERC. The net debt outstanding at AEL&P does not include the Snettisham obligation as this relates to a power purchase agreement for which AEL&P has recorded a long-term power purchase asset and corresponding liability to reflect their obligation under this contract.

In August 2012, we entered into two sales agency agreements under which we may sell up to 2.7 million shares of our common stock from time to time. As of September 30, 2013, we had 1.8 million shares available to be issued under these agreements; however, we do not plan to issue any shares under these agreements during 2013.

In the nine months ended September 30, 2013, we issued $4.5 million (net of issuance costs) of common stock under the dividend reinvestment and direct stock purchase plan, and employee plans and we are planning to issue an additional $1.5 million under these plans in the fourth quarter.

Our planned common stock issuances for 2013 have decreased from our previous estimate of $50.0 million due to our ongoing business requirements and due to our planned acquisition of AERC (discussed above), which is expected to be funded primarily through the issuance of common stock during 2014. We expect our capital structure at year-end to remain at an appropriate level for our business.

For 2014, we expect to issue up to $145 million of common stock related to closing the planned acquisition. Without the planned transaction, Avista Corp. would have required up to $75 million of common stock to maintain an appropriate capital structure.

After considering the issuances of long-term debt and common stock during 2013, we expect net cash flows from operating activities, together with cash available under our $400 million committed line of credit agreement, to provide adequate resources to fund capital expenditures, dividends, and other contractual commitments.

Avista Utilities – Regulatory Matters

General Rate Cases

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

- provide for recovery of operating costs and capital investments, and
- provide the opportunity to improve our earned 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. We filed general rate cases in Washington in April 2012 (which were settled with new rates effective January 1, 2013 and January 1, 2014), in Idaho in October 2012 (which were settled with new rates effective April 1, 2013 and October 1, 2013) and in Oregon in August 2013, the OPUC has up to 10 months to review and issue a decision.

Washington General Rate Cases

A settlement agreement approved by the UTC in December 2011 regarding electric and natural gas general rate cases filed in May 2011 provided for the deferral of certain generation plant maintenance costs. For 2011 and 2012 the Company compared actual, non-fuel, maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of baseline maintenance expenses used to establish base retail rates, and deferred the difference. This deferral occurred each year, with no carrying charge, with deferred costs to be amortized over a four-year period, beginning in the year following the period costs are deferred. Total net deferred costs under this mechanism in Washington were a regulatory asset of $3.3 million as of September 30, 2013 compared to $4.0 million as of December 31, 2012. As part of the settlement agreement to our latest general rate case approved in December 2012, the parties agreed to terminate the maintenance cost deferral mechanism on December 31, 2012, with the four-year amortization of the 2011 and 2012 deferrals to conclude in 2015 and 2016, respectively.

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

The approved settlement also provides that, effective January 1, 2014, we will increase base rates for our Washington electric customers by an overall 3.0 percent (designed to increase annual revenues by $14.0 million), and for our Washington natural gas customers by an overall 0.9 percent (designed to increase annual revenues by $1.4 million). The settlement provides for a one-year credit of $9.0 million to electric customers from the then-existing ERM deferral balance, if such funds are available, so the net average electric rate increase to our customers effective January 1, 2014 will be 2.0 percent. The credit to customers from the ERM balance will not impact our earnings. The ERM rebate balance as of September 30, 2013 was $20.1 million.

The UTC Order approving the settlement agreement included certain conditions. The new retail rates to become effective January 1, 2014 will be 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. Included in the original settlement agreement is a provision that we will not file a general rate case in Washington seeking new rates to take effect before January 1, 2015. We can, however, make a filing prior to January 1, 2015, but new rates resulting from the filing would not take effect prior to January 1, 2015. We currently intend to file a general rate case in the first quarter of 2014 with proposed rates that would take effect on January 1, 2015. This provision does not preclude us from filing other rate adjustments such as the PGA.

In addition, in its Order, the UTC found that much of the approved base rate increases are 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 original settlement agreement, this could result in base rates which are considered too high by the UTC. As a result, 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. We expect total utility capital expenditures among all jurisdictions to be approximately $280 million for 2013, $335 million for 2014, and $360 million for 2015, which is above the capital expenditures contemplated in the settlement agreement.

The settlement agreement provides for an authorized return on equity 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.

Idaho General Rate Cases

A settlement agreement approved by the IPUC in September 2011 regarding electric and natural gas general rate cases filed in July 2011 provided for the deferral of certain generation plant operation and maintenance costs. In order to address the variability in year-to-year operation and maintenance costs, beginning in 2011, we are deferring certain changes in operation and maintenance costs related to the Coyote Springs 2 natural gas-fired generation plant and our 15 percent ownership interest in Units 3&4 of the Colstrip generation plant. We compare actual, non-fuel, operation and maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of expenses authorized for recovery in base rates in the applicable deferral year, and defer the difference from that currently authorized. The deferral occurs annually, with no carrying charge, with deferred costs being amortized over a three-year period, beginning in the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases will be the actual operation and maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. Total net deferred costs under this mechanism in Idaho were regulatory assets of $2.6 million as of September 30, 2013 and $2.3 million as of December 31, 2012.

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 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 Avista Corp.'s 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.

Also included in the settlement agreement is a provision that we may 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. We currently intend to file a general rate case in the second quarter of 2014 with proposed rates that would take effect on January 1, 2015. This provision does not preclude us from filing other rate adjustments such as the PGA.

The settlement agreement provided for an authorized return on equity 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 return on equity, we will refund to customers 50 percent of any earnings above the 9.8 percent.

Oregon General Rate Case

On August 15, 2013, we filed a natural gas general rate case with the Public Utility Commission of Oregon (OPUC). We have requested an overall increase in billed natural gas rates of 9.8 percent (9.5 percent in base rates). The filing is designed to increase annual natural gas revenues by $9.5 million. Our request is based on a proposed overall rate of return of 7.83 percent, with a common equity ratio of 50 percent and a 10.1 percent return on equity. The OPUC has up to 10 months to review the filing and issue a decision.

Bonneville Power Administration Reimbursement and Reardan Wind Generation Project

On May 9, 2013, the UTC approved our Petition for an order authorizing certain accounting and ratemaking treatment related to two issues. The first issue relates to transmission revenues associated with a settlement between Avista Corp. and the Bonneville Power Administration (Bonneville), whereby Bonneville reimbursed the Company $11.7 million for Bonneville's past use of our transmission system. The second issue relates 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 Bonneville settlement payment, representing the entire portion of the settlement allocable to our Washington business. However, this amount will be 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 to be retained for the benefit of shareholders.

Bonneville has agreed to pay $0.3 million monthly 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), and will implement 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 Bonneville 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 for supply that is not hedged. Total net deferred natural gas costs among all jurisdictions were a liability of $4.9 million as of September 30, 2013 and a liability of $6.9 million as of December 31, 2012.

The following PGAs went into effect in our various jurisdictions during 2012 and 2013:

Jurisdiction	PGA Effective Date	Percentage Increase / (Decrease) in Billed Rates
Washington	March 1, 2012	(6.4)%
	November 1, 2012 (1)	(4.4)%
	November 1, 2013	9.2%
Idaho	March 1, 2012	(6.0)%
	October 1, 2012	(3.1)%
	October 1, 2013	7.5%
Oregon	November 1, 2012 (2)	(7.5)%
	January 1, 2013 (2)	(0.8)%
	November 1, 2013	(7.9)%

(1) As it relates to the Washington PGA, effective November 1, 2012, the UTC approved, on a temporary basis, our PGA and the PGAs for the other three natural gas utilities operating in Washington. The UTC approved the recommendation of the staff of the UTC that it be allowed more time to evaluate all four natural gas utilities' hedging transactions, potential implications of instituting natural gas procurement and hedging guidelines, and potential uniformity as it relates to PGA filings. In April 2013, the UTC approved the PGA rates on a permanent basis; however, the UTC staff continues to recommend workshops surrounding natural gas hedging programs. The timing and extent of the workshops has not been determined.

(2) As it relates to the 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 the margin on 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 $20.1 million as of September 30, 2013, compared to a liability of $22.2 million as of December 31, 2012, 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 a one-year credit of $4.4 million is being returned to electric customers from the existing ERM deferral balance to reduce the net average electric rate increase impact to customers in 2013. Additionally, during 2014 a one-year credit up to $9.0 million will be returned to electric customers from the then-existing ERM deferral balance, if such funds are available, so the net average electric rate increase impact to customers effective January 1, 2014 would also be reduced. The credits to customers from the ERM balances would 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 28, 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 2012 ERM deferred power cost transactions were approved by an order from the UTC.

As part of the April 2012 Washington general rate case filing, we proposed modifications to the ERM deadband and other sharing bands. The proposed modifications were not agreed to as part of the settlement agreement, and the ERM will continue unchanged. However, the trigger point at which rates will change under the ERM was modified to be $30 million rather than the previous 10 percent of base revenues (approximately $45 million) under the mechanism.

We have a PCA mechanism in Idaho that allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. The October 1 rate adjustments recover or rebate power supply costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a liability of $0.1 million as of September 30, 2013 compared to a liability of $5.1 million as of December 31, 2012.

Natural Gas Safety Regulations

On February 3, 2012, President Obama signed into law the "Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011" mandating new regulations be created to address public safety concerns. Although comprehensive, a primary focus of this Act is to require review of natural gas transmission pipeline records for completeness. We have reviewed our records and found them to be approximately 96 percent complete. It is expected to cost an immaterial amount to remedy this deficiency. At this time, we have not established a completion date because further rulemaking on what is needed to bring our system in to compliance is still in progress.

In addition to the above, in 2011, we began implementation of a plan to replace certain vintages of Aldyl A natural gas pipe within our distribution systems in Washington, Idaho, and Oregon. In early 2012, we released our protocol report to each state utility commission describing our Aldyl A natural gas pipe replacement plan across its natural gas system. Later in 2012, after technical workshops held by the UTC to gather perspectives on pipeline replacement programs, including the need for expedited cost recovery, the UTC required all natural gas utilities operating in Washington to file applicable replacement plans with the Commission. We subsequently filed our protocol report with the UTC proposing to replace our Aldyl A natural gas pipe across our three state jurisdictions over a 20-year period at a cost of approximately $10 million per year, indexed to inflation. Subsequent to this protocol report, during the third quarter of 2013, we revised our estimated replacement costs to approximately $16 million per year, indexed to inflation over a 20-year period. We expect to receive cost recovery for these capital expenditures from the three jurisdictions over the life of these assets.

Results of Operations

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

Three months ended September 30, 2013 compared to the three months ended September 30, 2012

Utility revenues decreased $13.6 million, after elimination of intracompany revenues of $32.1 million for the third quarter of 2013 and $14.5 million for the third quarter of 2012. Including intracompany revenues, electric revenues increased $0.1 million and natural gas revenues increased $3.9 million. Retail electric revenues increased $0.5 million primarily due to a change in revenue mix, with a greater percentage of retail revenue from residential and commercial customers, and the Washington general rate increase. This was partially offset by a decrease in industrial revenues due to decreased sales volumes. Wholesale electric revenues decreased $1.7 million due to a decrease in sales volumes partially offset by an increase in sales prices while sales of fuel increased $0.7 million. Retail natural gas revenues increased $0.4 million due to an increase in volumes, partially offset by a decrease in rates from PGAs, while wholesale natural gas revenues increased $3.1 million due to an increase in prices, partially offset by a decrease in volumes.

Ecova revenues increased $7.8 million to $46.4 million primarily as a result of an increase in revenues associated with expense and data management services, new services, and energy management services. Third quarter results benefited from the recognition of a $2.3 million rebate associated with achieving certain milestones on a five-year contract related to expense and data management services.

Utility resource costs decreased $22.7 million, after elimination of intracompany resource costs of $32.1 million for the third quarter of 2013 and $14.5 million for third quarter of 2012. Including intracompany resource costs, electric resource costs decreased $7.4 million and natural gas resource costs increased $2.4 million. The decrease in electric resource costs was primarily due to a decrease in power cost amortizations and power purchased, partially offset by an increase in fuel costs (due to an increase in natural gas generation and higher natural gas fuel prices) and an increase in other regulatory amortizations.

Utility other operating expenses increased $3.1 million and was the result of increased generation and gas distribution related operating and maintenance expenses and increased pension and other benefit costs. These were partially offset by decreases in administrative and general salaries and other production related expenses.

Utility depreciation and amortization increased $1.6 million driven by additions to utility plant.

Utility taxes other than income taxes increased $0.6 million primarily due to increased municipal and property related taxes.

Ecova other operating expenses increased $3.2 million primarily reflecting increased costs associated with new services and higher revenue volumes in energy management services.

Ecova depreciation and amortization increased $0.6 million primarily due to additions to software development costs and an impairment charge of $0.3 million associated with an intangible asset that was written off during the third quarter of 2013.

Interest expense increased $0.4 million primarily due to the issuance of long-term debt in November 2012 that increased the balance of long-term debt outstanding.

Other income-net increased $1.4 million primarily due to an increase in equity-related AFUDC of $0.5 million and a decrease in net losses on investments of $1.1 million. Included in the third quarter 2013 net losses on investments is an impairment loss of $1.3 million pre-tax ($0.8 million after-tax) associated with our investment in an energy storage company. Included in the third quarter 2012 net losses on investments is an impairment loss of $2.4 million pre-tax ($1.5 million after-tax) related to the impairment of our investment in a fuel cell business and the write-off of our investment in a solar energy company.

Income taxes increased $3.9 million and our effective tax rate was 31.4 percent for the third quarter of 2013 compared to 35.9 percent for the third quarter of 2012. The increase in expense was primarily due to an increase in income before income taxes. The decrease in the effective tax rate was primarily due to a tax provision to tax return true-up related to the 2012 tax return, a Section 199 deduction that we had previously been unable to utilize, and a deduction related to our pension funding.

Nine months ended September 30, 2013 compared to the nine months ended September 30, 2012

Utility revenues increased $16.5 million, after elimination of intracompany revenues of $105.5 million for the nine months ended September 30, 2013 and $54.5 million for the nine months ended September 30, 2012. Including intracompany revenues, electric revenues increased $56.2 million and natural gas revenues increased $11.2 million. Wholesale electric revenues increased $29.0 million and sales of fuel increased $10.9 million. Other electric revenues increased $13.8 million primarily due to the receipt of revenue from Bonneville for past use of our electric transmission system. Retail electric revenues increased $2.5 million primarily due to increases in residential and commercial cooling loads in the second and third quarters, partially offset by a decrease in the first quarter. There was a slight decrease in usage at industrial customers due to a new contract at one of our largest industrial customers which became effective July 1, 2013, partially offset by increased usage at certain industrial customers that had temporary operational challenges in 2012. Retail natural gas revenues decreased $12.6 million primarily due to a decrease in rates from PGAs partially offset by a slight increase in volumes. Wholesale natural gas revenues increased $22.4 million due to an increase in prices, partially offset by a decrease in volumes.

Ecova revenues increased $17.7 million to $133.4 million primarily as a result of an increase in revenues associated with new services, expense and data management services, and energy management services. In addition, year-to-date results benefited from the recognition of a $2.3 million rebate during the third quarter associated with achieving certain milestones on a five-year contract related to expense and data management services.

Utility resource costs decreased $13.5 million, after elimination of intracompany resource costs of $105.5 million for the nine months ended September 30, 2013 and $54.5 million for the nine months ended September 30, 2012. Including intracompany resource costs, electric resource costs increased $29.7 million and natural gas resource costs increased $7.7 million. The increase in electric resource costs was primarily due to an increase in fuel costs (due to higher natural gas generation and higher natural gas fuel prices), 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), power purchased, and the write-off of $2.5 million of Reardan project costs that are allocable to our Washington business. The increase in natural gas resource costs was primarily due to an increase in natural gas prices, partially offset by a decrease in volumes.

Utility other operating expenses increased $4.1 million as a result of increased production and gas distribution related operating and maintenance expenses, partially offset by decreases in generation maintenance expenses and administrative and general expenses which resulted from management initiatives to control the growth in operating costs, including the voluntary severance incentive plan implemented in the fourth quarter of 2012.

Utility depreciation and amortization increased $3.5 million driven by additions to utility plant.

Taxes other than income taxes increased $2.4 million primarily due to increased franchise, municipal, and property related taxes.

Ecova other operating expenses increased $6.4 million primarily reflecting increased costs associated with new services and higher revenue volumes in expense and data management services, and these were partially offset by a decrease in integration and acquisition costs of $1.5 million, which Ecova incurred during the first quarter of 2012 and did not reoccur during 2013.

Ecova depreciation and amortization increased $2.0 million primarily due to additions to software development costs, additional amortization of intangibles recorded in connection with Ecova's acquisitions, and the impairment of $0.4 million of intangible assets during 2013.

Other non-utility operating expenses increased $0.5 million primarily due to increased costs associated with strategic investments, increased operating and maintenance and other expenses at METALfx, partially offset by decreased legal costs associated with the previous operations of Avista Energy.

Interest expense increased $1.7 million primarily due to the issuance of long-term debt in November 2012 that increased the balance of long-term debt outstanding.

Other income-net increased $2.7 million primarily due to an increase in equity-related AFUDC of $1.5 million and a decrease in net losses on investments of $1.4 million. Included in the net losses on investments for the first nine months of 2013 is an impairment loss of $1.7 million pre-tax ($1.1 million after-tax) associated with our investment in an energy storage company. Included in the net losses on investments for the first nine months of 2012 is an impairment loss of $2.4 million pre-tax ($1.5 million after-tax) related to the impairment of our investment in a fuel cell business and the write-off of our investment in a solar energy company.

Income taxes increased $13.0 million and our effective tax rate was 36.3 percent for the nine months ended September 30, 2013 compared to 34.6 percent for the nine months ended September 30, 2012. The increase in expense was primarily due to an increase in income before income taxes. The change in the effective tax rate is primarily related to a change in the amount of our pension contribution deduction.

Avista Utilities

Non-GAAP Financial Measures

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

Three months ended September 30, 2013 compared to the three months ended September 30, 2012

Net income for Avista Utilities was $9.4 million for the third quarter of 2013, an increase from $7.7 million for the third quarter of 2012. Avista Utilities’ income from operations was $29.7 million for the third quarter of 2013, an increase from $25.9 million for the third quarter of 2012. The increase in net income and income from operations was primarily due to the implementation of general rate increases in Washington and warmer weather that increased cooling loads, partially offset by expected increases in other operating expenses, depreciation and amortization, and taxes other than income taxes.

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

	Electric		Natural Gas		Intracompany		Total	
	2013	2012	2013	2012	2013	2012	2013	2012
Operating revenues	$ 240,317	$ 240,187	$ 70,745	$ 66,850	$ (32,139)	$ (14,502)	$ 278,923	$ 292,535
Resource costs	110,900	118,311	52,375	49,992	(32,139)	(14,502)	131,136	153,801
Gross margin	$ 129,417	$ 121,876	$ 18,370	$ 16,858	$ —	$ —	$ 147,787	$ 138,734

Avista Utilities' operating revenues decreased $13.6 million and resource costs decreased $22.6 million, which resulted in an increase of $9.0 million in gross margin. The gross margin on electric sales increased $7.5 million and the gross margin on natural gas sales increased $1.5 million. The increase in electric gross margin was primarily due to the Washington general rate increase and weather that was warmer than normal and warmer than the prior year which increased cooling loads. For the third quarter of 2013, we recognized a pre-tax expense of $4.7 million under the ERM in Washington compared to a benefit of $0.8 million for the third quarter of 2012. This change was primarily due to the Colstrip outage. The slight increase in natural gas gross margin was due to the Washington and Idaho general rate increases and colder weather in late September, which increased heating loads.

Intracompany revenues and resource costs represent purchases and sales of natural gas between our natural gas distribution operations and our electric generation operations (that use natural gas 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	
	2013	2012	2013	2012
Residential	$ 73,800	$ 70,534	839	809
Commercial	77,776	76,180	854	841
Industrial	27,645	31,994	465	555
Public street and highway lighting	1,857	1,824	6	6
Total retail	181,078	180,532	2,164	2,211
Wholesale	24,104	25,826	623	872
Sales of fuel	29,088	28,385	—	—
Other	6,047	5,444	—	—
Total	$ 240,317	$ 240,187	2,787	3,083

Retail electric revenues increased $0.5 million due to an increase in revenue per MWh (increased revenues $4.6 million) partially offset by a decrease in total MWhs sold (decreased revenues $4.1 million). The increase in revenue per MWh was primarily due to a change in revenue mix, with a greater percentage of retail revenue from residential and commercial customers, and the Washington general rate increase, partially offset by other rate changes that do not impact gross margin (including the ERM rebate). The decrease in total MWhs sold was primarily due to a decrease in industrial sales volumes, partially offset by an increase in residential and commercial sales volumes as a result of warmer weather (and increased cooling loads).

The decrease in industrial sales volumes and revenues was due to a new agreement (effective July 1, 2013) with one of our largest industrial customers. Under the new agreement, 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, will be tracked through the PCA in Idaho at 100 percent, so that we expect no impact on our gross margin or net income from the new agreement.

Compared to the third quarter of 2012, residential electric use per customer increased 3 percent and commercial use per customer increased 1 percent. Cooling degree days at Spokane were 88 percent above historical average for the third quarter of 2013, and 25 percent above the third quarter of 2012.

Wholesale electric revenues decreased $1.7 million due to a decrease in sales volumes (decreased revenues $9.6 million), partially offset by an increase in sales prices (increased revenues $7.9 million). The fluctuation in volumes and prices was primarily the result of our optimization activities during the quarter.

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market rather than operate the generating units. The revenues from sales of fuel increased $0.7 million. For the third quarter of 2013, $22.7 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For the third quarter of 2012, $4.8 million of these sales were made to our natural gas operations.

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

The 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	
	2013	2012	2013	2012
Residential	$ 17,448	$ 16,998	13,022	12,478
Commercial	10,057	10,134	11,248	10,891
Interruptible	547	441	1,250	859
Industrial	667	700	955	946
Total retail	28,719	28,273	26,475	25,174
Wholesale	38,439	35,349	115,754	136,825
Transportation	1,600	1,587	33,767	32,059
Other	1,987	1,641	18	14
Total	$ 70,745	$ 66,850	176,014	194,072

Retail natural gas revenues increased $0.4 million due an increase in volumes (increased revenues $1.4 million), partially offset by lower retail rates (decreased revenues $1.0 million). Lower retail rates were due to PGAs, partially offset by the Washington general rate case. We sold more retail natural gas in the third quarter of 2013 as compared to the third quarter of 2012 primarily due to colder weather in late September. Compared to the third quarter of 2012, residential natural gas use per customer increased 4 percent and commercial use per customer increased 3 percent. Heating degree days at Spokane were 41 percent below historical average for the third quarter of 2013; however, they were 64 percent above the third quarter of 2012. Heating degree days at Medford were 2 percent below historical average for the third quarter of 2013. Also, there were 84 heating degree days in the third quarter of 2013 compared to 1 heating degree day in the third quarter of 2012.

Wholesale natural gas revenues increased $3.1 million due to an increase in prices (increased revenues $10.1 million), partially offset by a decrease in volumes (decreased revenues $7.0 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 2013, $9.4 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 2012, $9.7 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	
	2013	2012	2013	2012
Residential	320,685	318,413	287,541	285,710
Commercial	40,178	39,892	33,814	33,667
Interruptible	—	—	40	41
Industrial	1,387	1,402	259	263
Public street and highway lighting	528	542	—	—
Total retail customers	362,778	360,249	321,654	319,681

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

	2013	2012
Electric resource costs:		
Power purchased	$ 40,901	$ 48,803
Power cost amortizations, net	(6,751)	4,794
Fuel for generation	36,060	27,741
Other fuel costs	30,908	28,430
Other regulatory amortizations, net	5,015	3,754
Other electric resource costs	4,767	4,789
Total electric resource costs	110,900	118,311
Natural gas resource costs:		
Natural gas purchased	55,044	52,623
Natural gas cost amortizations, net	(3,044)	(3,198)
Other regulatory amortizations, net	375	567
Total natural gas resource costs	52,375	49,992
Intracompany resource costs	(32,139)	(14,502)
Total resource costs	$ 131,136	$ 153,801

Power purchased decreased $7.9 million due to a decrease in the volume of power purchases (decreased costs $3.8 million) and a decrease in wholesale prices (decreased costs $4.1 million). The fluctuation in volumes and prices was primarily the result of our overall optimization activities during the quarter.

Amortizations of net deferred power costs decreased electric resource costs by $6.8 million for the three months ended September 30, 2013 compared to an increase of $4.8 million to electric resource costs for the three months ended September 30, 2012. During the three months ended September 30, 2013, we refunded to customers $0.7 million of previously deferred power costs in Idaho through the PCA rebate. As part of the Washington rate case settlement implemented on January 1, 2013, we refunded to customers $1.0 million through an ERM rebate. During the three months ended September 30, 2013, actual power supply costs were above the amount included in base retail rates and we reversed the deferral of $0.5 million under the ERM in Washington. We also deferred $4.5 million in Idaho for potential future surcharge to customers.

Fuel for generation increased $8.3 million due to an increase in natural gas generation and an increase in natural gas fuel prices. Generation at Colstrip decreased due to an outage at Unit 4.

Other fuel costs increased $2.5 million. This 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. When the fuel is sold, the revenue generated from selling the fuel is included in the sales of fuel revenue line item above.

The expense for natural gas purchased increased $2.4 million due to an increase in the price of natural gas (increased costs $10.1 million), partially offset by a decrease in total therms purchased (decreased costs $7.7 million). Total therms purchased decreased due to a decrease in wholesale sales which are used to balance loads and resources as part of the natural gas procurement and resource optimization process, partially offset by an increase in retail sales. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs.

Nine months ended September 30, 2013 compared to the nine months ended September 30, 2012

Net income for Avista Utilities was $76.3 million for the nine months ended September 30, 2013, an increase from $65.2 million for the nine months ended September 30, 2012. Avista Utilities' income from operations was $167.6 million for the nine months ended September 30, 2013, an increase from $147.6 million for the nine months ended September 30, 2012. The increase in net income and income from operations was primarily due to the implementation of general rate increases in Washington and the net benefit from the settlement with Bonneville, 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	
	2013	2012	2013	2012	2013	2012	2013	2012
Operating revenues	$ 772,252	$ 716,090	$ 341,872	$ 330,631	$ (105,455)	$ (54,511)	$ 1,008,669	$ 992,210
Resource costs	354,682	325,011	238,050	230,305	(105,455)	(54,511)	487,277	500,805
Gross margin	$ 417,570	$ 391,079	$ 103,822	$ 100,326	$ —	$ —	$ 521,392	$ 491,405

Avista Utilities' operating revenues increased $16.5 million and resource costs decreased $13.5 million, which resulted in an increase of $30.0 million in gross margin. The gross margin on electric sales increased $26.5 million and the gross margin on natural gas sales increased $3.5 million. The increase in both electric and natural gas gross margin was primarily due to the Washington general rate increases. The increase in electric gross margin was also due to warmer weather and increased cooling loads during the summer. In addition, electric gross margin increased due to the net benefit from the settlement with Bonneville of $5.1 million. For the nine months ended September 30, 2013, we recognized a pre-tax expense of $0.5 million under the ERM in Washington compared to a benefit of $5.9 million for the nine months ended September 30, 2012. This change was primarily due to the Colstrip outage.

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	
	2013	2012	2013	2012
Residential	$ 237,088	$ 232,762	2,695	2,650
Commercial	215,899	215,875	2,356	2,348
Industrial	88,230	90,226	1,547	1,569
Public street and highway lighting	5,534	5,431	19	19
Total retail	546,751	544,294	6,617	6,586
Wholesale	101,065	72,019	3,135	2,832
Sales of fuel	94,348	83,444	—	—
Other	30,088	16,333	—	—
Total	$ 772,252	$ 716,090	9,752	9,418

Retail electric revenues increased $2.5 million due to an increase in total MWhs sold (increased revenues $2.5 million) primarily due to increases in residential and commercial cooling loads in the second and third quarters, partially offset by a decrease during the first quarter. The slight decrease in total MWhs sold to industrial customers was primarily due to a new contract at one of our largest industrial customers which became effective July 1, 2013, partially offset by increased usage at certain industrial customers that had temporary operational challenges in 2012. Residential use per customer increased 1 percent from 2012 to 2013 with lower usage in the first quarter offset by higher usage in the second and third quarters primarily due to weather. Cooling degree days at Spokane were 80 percent above historical average for 2013, and 33 percent above 2012.

Revenue per MWh did not change significantly due to changes in revenue mix, as well as other rate changes that do not impact gross margin (including the ERM rebate), offset by general rate increases.

Wholesale electric revenues increased $29.0 million due to an increase in sales volumes (increased revenues $9.7 million) and an increase in sales prices (increased revenues $19.3 million), which were related to an increase in optimization activities.

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market rather than operate the generating units. The revenues from sales of fuel increased $10.9 million due to an increase in sales of natural gas fuel as part of thermal generation resource optimization activities, as well as an increase in natural gas prices. For the nine months ended September 30, 2013, $76.9 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, 2012, $23.6 million of these sales were made to our natural gas operations.

Other electric revenues increased $13.8 million primarily due to the receipt of $11.7 million of revenue from Bonneville for past use of our electric transmission system. See further information above at "Bonneville Power Administration Reimbursement and Reardan Wind Generation Project."

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 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	
	2013	2012	2013	2012
Residential	$ 127,742	$ 135,281	125,075	124,844
Commercial	64,497	69,423	77,297	77,806
Interruptible	1,807	1,674	3,914	3,171
Industrial	2,532	2,790	3,693	3,781
Total retail	196,578	209,168	209,979	209,602
Wholesale	133,573	111,181	374,142	449,492
Transportation	5,435	5,155	114,084	112,320
Other	6,286	5,127	300	286
Total	$ 341,872	$ 330,631	698,505	771,700

Retail natural gas revenues decreased $12.6 million primarily due to lower retail rates (decreased revenues $12.9 million) partially offset by a slight increase in volumes (increased revenues $0.3 million). Lower retail rates were due to PGAs, partially offset by the Washington general rate case. Heating degree days at Spokane were 4 percent below historical average for the nine months ended September 30, 2013, and 1 percent above the nine months ended September 30, 2012. Heating degree days at Medford were 7 percent below historical average for the nine months ended September 30, 2013, and 2 percent below the nine months ended September 30, 2012.

Wholesale natural gas revenues increased $22.4 million due to an increase in prices (increased revenues $49.3 million), partially offset by a decrease in volumes (decreased revenues $26.9 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, 2013, $28.6 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, 2012, $30.9 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	
	2013	2012	2013	2012
Residential	320,461	318,368	288,253	286,268
Commercial	40,133	39,836	33,958	33,754
Interruptible	—	—	38	38
Industrial	1,386	1,397	260	261
Public street and highway lighting	526	497	—	—
Total retail customers	362,506	360,098	322,509	320,321

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

	2013	2012
Electric resource costs:		
Power purchased	$ 144,582	$ 138,669
Power cost amortizations, net	(7,188)	9,889
Fuel for generation	90,672	62,608
Other fuel costs	93,103	86,961
Other regulatory amortizations, net	16,478	12,925
Other electric resource costs	17,035	13,959
Total electric resource costs	354,682	325,011
Natural gas resource costs:		
Natural gas purchased	235,803	224,037
Natural gas cost amortizations, net	(2,277)	529
Other regulatory amortizations, net	4,524	5,739
Total natural gas resource costs	238,050	230,305
Intracompany resource costs	(105,455)	(54,511)
Total resource costs	$ 487,277	$ 500,805

Power purchased increased $5.9 million due to an increase in the volume of power purchases (increased costs $5.0 million) and an increase in wholesale prices (increased costs $0.9 million). The fluctuation in volumes and prices was primarily the result of our overall optimization activities during the period.

Amortizations of net deferred power costs decreased electric resource costs by $7.2 million for the nine months ended September 30, 2013 compared to an increase of $9.9 million to electric resource costs for the nine months ended September 30, 2012. During the nine months ended September 30, 2013, we refunded to customers $2.2 million of previously deferred power costs in Idaho through the PCA rebate. As part of the Washington rate case settlement implemented on January 1, 2013, we refunded to customers $2.9 million through an ERM rebate. During the nine months ended September 30, 2013, actual power supply costs were above the amount included in base retail rates and we deferred $2.9 million in Idaho for potential future surcharge to customers.

Fuel for generation increased $28.1 million due to an increase in natural gas generation and an increase in natural gas fuel prices. Generation at Colstrip decreased due to an outage at Unit 4.

Other fuel costs increased $6.1 million. This 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. When the fuel is sold, the revenue generated from selling the fuel is included in the sales of fuel revenue line item above.

Electric other regulatory amortizations increased $3.6 million primarily due to the regulatory deferral of $3.9 million for the Idaho portion of the Bonneville revenue for future refund to our Idaho customers and $1.6 million of 2013 Bonneville revenue deferred for future rebate to our Washington customers. These increases were partially offset by a decrease in demand side management program costs.

Other electric resource costs increased $3.1 million primarily due to the write-off of $2.5 million of Reardan project costs that are allocable to our Washington business.

The expense for natural gas purchased increased $11.8 million due to an increase in the price of natural gas (increased costs $42.0 million), partially offset by a decrease in total therms purchased (decreased costs $30.2 million). Total therms purchased decreased due to a decrease in wholesale sales which are used to balance loads and resources as part of the natural gas procurement and resource optimization process, partially offset by a slight increase in retail sales. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs.

Ecova

Three months ended September 30, 2013 compared to the three months ended September 30, 2012

Ecova's net income attributable to Avista Corp. shareholders was $3.0 million for the three months ended September 30, 2013 compared to $0.6 million for the three months ended September 30, 2012. Operating revenues increased $7.8 million and total operating expenses increased $3.8 million. The increase in operating revenues was primarily the result of an increase associated with expense and data management services, energy management services and new services which added $3.9 million, $2.5 million and $1.4 million to revenue, respectively. The increase in expense and data management services was primarily the result of the recognition of a $2.3 million rebate during the third quarter associated with achieving certain milestones on a five-year contract related to expense and data management services.

Ecova's other operating expenses associated with cost of services increased $3.1 million for the third quarter of 2013 and totaled $23.5 million. This increase was primarily due to expenses associated with new services and higher revenue volumes in energy management services.

Ecova's other operating expenses associated with selling, general and administrative expenses increased by $0.1 million in the third quarter of 2013 and totaled $13.5 million. This increase was primarily the result of an increase in employee related costs, partially offset by lower severance and outside service fees.

Depreciation and amortization at Ecova increased $0.6 million primarily due to additions to software development costs and an impairment charge of $0.3 million associated with an intangible asset that was written off during the third quarter.

As of September 30, 2013, Ecova had over 700 expense management customers representing over 700,000 billed sites in North America. In the third quarter of 2013, Ecova managed bills totaling $5.5 billion, an increase of $6.4 million as compared to the third quarter of 2012. The increase in bills managed was due to an increase in the number of billed sites.

Nine months ended September 30, 2013 compared to the nine months ended September 30, 2012

Ecova's net income attributable to Avista Corp. shareholders was $5.8 million for the nine months ended September 30, 2013 compared to $1.0 million for the nine months ended September 30, 2012. Operating revenues increased $17.7 million and total operating expenses increased $8.4 million. The increase in operating revenues was primarily the result of increased revenues associated with new services, which added $7.8 million to revenue. In addition, there were increases associated with expense and data management services and energy management services (primarily an increase in volumes), which added $6.6 million and $3.3 million to revenue, respectively. In addition to the volume increase, the increase in expense and data management services was partially the result of the recognition of a $2.3 million rebate during the third quarter associated with achieving certain milestones on a five-year contract related to expense and data management services.

Ecova's other operating expenses associated with cost of services increased $8.7 million for the first nine months of 2013 and totaled $70.8 million due to expenses associated with new services and higher revenue volumes in expense and data management services.

Ecova's other operating expenses associated with selling, general and administrative expenses decreased by $2.3 million in the first nine months of 2013 and totaled $40.0 million. This decrease was primarily the result of a decrease in acquisition and integration costs of $1.5 million, which were incurred during the first quarter of 2012 and did not reoccur during 2013 and also a decrease in employee related costs, partially offset by the absence of a B&O tax refund that was received during 2012.

Depreciation and amortization increased $2.0 million due to additions to software development costs, additional amortization of intangibles recorded in connection with Ecova's acquisitions, and the impairment of $0.4 million of intangible assets during 2013.

In the first nine months of 2013, Ecova managed bills totaling $15.7 billion, an increase of $1.2 billion as compared to the first nine months of 2012 and was due to an increase in the number of billed sites.

Other Businesses

Our other businesses include sheet metal fabrication, venture fund investments and real estate investments, as well as certain other operations of Avista Capital. These activities do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp., including AM&D, doing business as METALfx.

The following table shows our assets related to our other businesses as of September 30, 2013 and December 31, 2012 (dollars in thousands):

	September 30, 2013	December 31, 2012
Spokane Energy (1)	$ 45,756	$ 54,235
Avista Energy	12,343	12,549
METALfx	11,503	11,273
Steam Plant and Courtyard Office Center	7,028	7,122
Other	10,526	10,459
Total	$ 87,156	$ 95,638

(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 8 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.

Three months ended September 30, 2013 compared to the three months ended September 30, 2012

The net loss from these operations was $1.1 million for the three months ended September 30, 2013 compared to a net loss of $2.5 million for the three months ended September 30, 2012. The net loss for the third quarter of 2013 was primarily the result of $0.5 million (net of tax) of corporate costs, including costs associated with exploring strategic opportunities to develop new markets and ways for customers to use electricity and natural gas for commercial productivity and transportation.

Additionally, during the third quarter of 2013 we incurred an impairment loss of $0.8 million (net of tax) associated with our investment in an energy storage company and litigation costs related to the previous operations of Avista Energy of $0.1 million (net of tax). During the third quarter of 2012 we incurred an impairment loss of $1.5 million (net of tax) related to the impairment of our investment in a fuel cell business and the write-off of our investment in a solar energy company.

These losses were partially offset by METALfx, which had net income of $0.5 million for the third quarter of 2013 as compared to net income of $0.3 million for the third quarter of 2012.

Nine months ended September 30, 2013 compared to the nine months ended September 30, 2012

The net loss from these operations was $2.6 million for the nine months ended September 30, 2013 compared to a net loss of $3.8 million for the nine months ended September 30, 2012. The net loss for the first nine months of 2013 was primarily the result of $1.5 million (net of tax) of corporate costs, including costs associated with exploring strategic opportunities.

Additionally, during the first nine months of 2013 we incurred an impairment loss of $1.1 million (net of tax) associated with our investment in an energy storage company and litigation costs related to the previous operations of Avista Energy of $0.7 million (net of tax). During the first nine months of 2012 we incurred an impairment loss of $1.5 million (net of tax) related to the impairment of our investment in a fuel cell business and the write-off of our investment in a solar energy company.

The losses above were partially offset by METALfx, which had net income of $1.1 million for each of the nine months ended September 30, 2013 and 2012.

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 2012 Form 10-K and have not changed materially from that discussion.

Liquidity and Capital Resources

Review of Cash Flow Statement

Overall During the nine months ended September 30, 2013, positive cash flows from operating activities of $202.4 million, proceeds from the issuance of long-term debt of $90.0 million and borrowings under our committed line of credit of $14.0 million were used to fund the majority of our cash requirements. These cash requirements included utility capital expenditures of $220.7 million and dividends of $55.0 million.

Operating Activities Net cash provided by operating activities was $202.4 million for the nine months ended September 30, 2013 compared to $257.4 million for the nine months ended September 30, 2012. Net cash provided by working capital components was $5.6 million for the first nine months of 2013, compared to net cash provided of $63.8 million for the first nine months of 2012. The net cash provided by working capital components 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 net cash provided by working capital components during the first nine months of 2012 primarily reflects positive cash flows related to accounts receivable and other current assets (primarily related to increases in other miscellaneous current assets, income taxes receivable, and prepayments), partially offset by a decrease in accounts payable.

Net amortization of deferred power and natural gas costs decreased operating cash flows by $10.1 million for the nine months ended September 30, 2013 compared to an increase in operating cash flows of $10.4 million for the nine months ended September 30, 2012. The provision for deferred income taxes was $16.5 million for the nine months ended September 30, 2013 compared to $18.4 million for the nine months ended September 30, 2012. Contributions to our defined benefit pension plan were $44.0 million for the first nine months of 2013 and 2012. Cash paid for income taxes was $33.5 million for the first nine months of 2013, compared to $12.5 million for the first nine months of 2012.

Investing Activities Net cash used in investing activities was $233.6 million for the nine months ended September 30, 2013, an increase compared to $229.1 million for the nine months ended September 30, 2012. Utility property capital expenditures increased by $42.3 million for the first nine months of 2013 as compared to the first nine months of 2012. A significant portion of Ecova's funds held for clients are held as securities available for sale (with purchases of $35.9 million and sales and maturities of $17.0 million for 2013 and purchases of $88.8 million and sales and maturities of $103.5 million for 2012). The $50.3 million of net cash paid by subsidiaries for acquisitions in the first nine months of 2012 represents Ecova's acquisitions.

Financing Activities Net cash provided by financing activities was $47.7 million for the nine months ended September 30, 2013 compared to net cash used of $20.1 million for the nine months ended September 30, 2012. During the first nine months of 2013, short-term borrowings on Avista Corp.'s committed line of credit increased $14.0 million. Net borrowings on Ecova's committed line of credit decreased $4.0 million during the period. Cash dividends paid increased to $55.0 million (or $0.915 per share) for the first nine months of 2013 from $51.2 million (or $0.87 per share) for the first nine months of 2012. We issued $4.5 million of common stock during the nine months ended September 30, 2013. We cash settled two interest rate swap contracts (notional amount of $85.0 million) in conjunction with the pricing and issuance of a $90.0 million term loan agreement that was completed in August 2013 and received a total of $2.9 million. Customer fund obligations at Ecova increased $7.4 million.

During the nine months ended September 30, 2012, short-term borrowings on Avista Corp.'s committed line of credit increased $21.0 million. Borrowings on Ecova's committed line of credit increased $28.0 million and these proceeds were used to fund a portion of an acquisition. We issued $28.7 million of common stock during the nine months ended September 30, 2012. In May 2012, we cash settled interest rate swap agreements and paid a total of $18.5 million. Customer fund obligations at Ecova decreased $5.2 million.

Overall Liquidity

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

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

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

We periodically file for rate adjustments for recovery of operating costs and capital investments to provide the opportunity to improve our earned returns as allowed by regulators. See further details in the section “Avista Utilities - Regulatory Matters.”

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

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

We monitor the potential liquidity impacts of changes to energy commodity prices and other increased operating costs for our utility operations. We believe that we have adequate liquidity to meet such potential needs through our $400 million committed line of credit.

As of September 30, 2013, we had $306.0 million of available liquidity under our committed line of credit. With our $400 million credit facility that expires in February 2017, we believe that we have adequate liquidity to meet our needs for the next 12 months.

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

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, 2013, we had cash deposited as collateral of $23.8 million and letters of credit of $20.1 million outstanding related to our energy derivative contracts. Price movements and/or a downgrade in our credit ratings could further impact the amount of collateral required. See “Credit Ratings” for further information. For example, in addition to limiting our ability to conduct transactions, if our credit ratings were lowered to below “investment grade” based on our positions outstanding at September 30, 2013, we would potentially be required to post additional collateral of up to $11.0 million. This amount is different from the amount disclosed in “Note 5 of the Notes to Condensed Consolidated Financial Statements” because, while this analysis includes contracts that are not considered derivatives in addition to the contracts considered in Note 5, this analysis takes into account contractual threshold limits that are not considered in Note 5. Without contractual threshold limits, we would potentially be required to post additional collateral of $30.3 million.

Under the terms of interest rate swap agreements that we enter into periodically, we may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the instrument. This has not historically been significant to our liquidity position. As of September 30, 2013, we had interest rate swap agreements outstanding with a notional amount totaling $165 million and we did not have any collateral posted. If our credit ratings were lowered to below “investment grade” based on our interest rate swap agreements outstanding at September 30, 2013, we would not be required to post additional collateral.

Dodd-Frank Wall Street Reform and Consumer Protection Act

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted into law in July 2010. The Dodd-Frank Act establishes regulatory jurisdiction by the Commodity Futures Trading Commission (CFTC) and the Securities and Exchange Commission (SEC) for certain swaps (which include a variety of derivative instruments) and certain users of such swaps that previously had been largely exempted from regulation.

During 2012, the Board of Directors of Avista Corp. approved the use of the end user exemption under Dodd-Frank. We expect most of our transactions to qualify under the end user exemption, and not be required to be cleared and traded on exchanges or swap execution facilities. We intend to use a clearing agent for most transactions; however, we have established agreements with several counterparties to enable bilateral transactions, if necessary.

We continue to monitor developments regarding implementation under the Dodd-Frank Act. At this time, while we cannot predict the full impact the Dodd-Frank Act may ultimately have on our operations, we do not anticipate that our operations will be materially impacted.

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, 2013 and December 31, 2012 (dollars in thousands):

	September 30, 2013		December 31, 2012	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 50,330	1.8%	$ 50,372	1.9%
Current portion of nonrecourse long-term debt (Spokane Energy)	16,022	0.6%	14,965	0.6%
Short-term borrowings	66,000	2.4%	52,000	1.9%
Long-term borrowings under committed line of credit	50,000	1.8%	54,000	2.0%
Long-term debt to affiliated trusts	51,547	1.8%	51,547	1.9%
Nonrecourse long-term debt (Spokane Energy)	5,666	0.2%	17,838	0.7%
Long-term debt	1,272,260	45.4%	1,178,367	44.0%
Total debt	1,511,825	54.0%	1,419,089	53.0%
Total Avista Corporation stockholders’ equity	1,289,404	46.0%	1,259,477	47.0%
Total	$ 2,801,229	100.0%	$ 2,678,566	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 stockholders’ equity increased $29.9 million during 2013 primarily due to net income partially offset by dividends.

We generally fund capital expenditures with a combination of internally generated cash and external financing. The level of cash generated internally and the amount that is available for capital expenditures fluctuates depending on a variety of factors. Cash provided by our utility operating activities, as well as issuances of long-term debt and common stock, are expected to be the primary source of funds for operating needs, dividends and capital expenditures for 2013. Borrowings under our $400 million committed line of credit will supplement these funds to the extent necessary.

In August 2012, we entered into two sales agency agreements under which we may sell up to 2.7 million shares of our common stock from time to time. As of September 30, 2013, we had 1.8 million shares available to be issued under these agreements; however, we do not plan to issue any shares under these agreements during 2013.

In the nine months ended September 30, 2013, we issued $4.5 million (net of issuance costs) of common stock under the dividend reinvestment and direct stock purchase plan, and employee plans and we are planning to issue an additional $1.5 million under these plans in the fourth quarter.

Our planned common stock issuances for 2013 have decreased from our previous estimate of $50.0 million due to our ongoing business requirements and due to our planned acquisition of AERC (discussed above), which is expected to be funded primarily through the issuance of common stock during 2014. We expect our capital structure at year-end to remain at an appropriate level for our business.

For 2014, we expect to issue up to $145 million of common stock related to closing the planned acquisition. Without the planned transaction, Avista Corp. would have required up to $75 million of common stock to maintain an appropriate capital structure.

In August 2013, we entered into a $90.0 million term loan agreement with an institutional investor that matures in 2016. The term loan agreement 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 we default on our obligations under the term loan agreement. The net proceeds from the term loan agreement were used to repay a portion of corporate indebtedness in anticipation of $50.0 million in First Mortgage Bonds maturing in December 2013.

During 2014, we expect to issue up to $190 million of long-term debt, including up to $90 million of debt issuances associated with rebalancing the consolidated capital structure at AERC. This amount assumes we are going to refinance the existing net debt outstanding at AEL&P. The net debt outstanding at AEL&P does not include the Snettisham obligation as this relates to a power purchase agreement.

We have a committed line of credit with various financial institutions in the total amount of $400 million with an expiration date of February 2017. Borrowings under this line of credit agreement are classified as short-term on the Condensed

Consolidated Balance Sheets.

This facility contains customary covenants and default provisions, including a covenant which does not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 65 percent at any time. As of September 30, 2013, we were in compliance with this covenant with a ratio of 54.0 percent.

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

	2013	2012
Borrowings outstanding at end of period	$ 66,000	$ 82,000
Letters of credit outstanding at end of period	$ 27,994	$ 26,815
Maximum borrowings outstanding during the period	$ 95,500	$ 92,500
Average borrowings outstanding during the period	$ 23,382	$ 25,000
Average interest rate on borrowings during the period	1.18%	1.17%
Average interest rate on borrowings at end of period	1.10%	1.08%

As part of their cash management practices and operations, Ecova and Avista Corp. entered into an arrangement under which Avista Corp. issued to Ecova a master unsecured promissory note and Ecova from time to time makes short-term loans to Avista Corp. as a temporary investment of its funds received from its clients. The master promissory note limits the total outstanding indebtedness to no more than $50.0 million in principal. Additionally, such loans are required to be repaid on the last business day of each quarter (March, June, September and December) and sooner upon demand by Ecova. Amounts are loaned at a rate consistent with Avista Corp.'s credit facility. The average balance outstanding was $32.1 million and the maximum balance was $50.0 million during the nine months ended September 30, 2013. The average balance outstanding was $32.9 million and the maximum balance was $50.0 million during the nine months ended September 30, 2012.

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, 2013, 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.

See the "Ecova Credit Agreement" section below for further information regarding Ecova's committed line of credit.

Avista Utilities Capital Expenditures

We expect utility capital expenditures to be about $280 million for 2013, $335 million for 2014, and $360 million for 2015. We increased our previous estimates for future capital expenditures from $260 million annually in 2014 and 2015 to meet an increased demand for utility capital projects associated with updating and maintaining our generation, transmission and energy distribution systems to ensure reliability. 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.

Included in our estimates of capital expenditures is the replacement of our customer information and work management systems, which is expected to be completed by the end of 2014. We expect to spend a total of approximately $80 million (including internal labor) over the term of the project. Major signed contracts for third parties total approximately $27 million as of September 30, 2013.

Ecova Credit Agreement

Ecova has a $125.0 million committed line of credit agreement with various financial institutions with an expiration date of July 2017. The credit agreement is secured by all of Ecova's assets excluding investments and funds held for clients. There were $50.0 million of borrowings outstanding under Ecova's credit agreement as of September 30, 2013 classified as long-term. The proceeds from these borrowings were used to fund acquisitions in 2011 and 2012.

The committed line of credit agreement contains customary covenants and default provisions, including a covenant which requires that Ecova's "Consolidated Total Funded Debt to EBITDA Ratio" (as defined in the credit agreement) must be 2.50 to 1.00 or less, with provisions in the credit agreement allowing for a temporary increase of this ratio if a qualified acquisition is consummated by Ecova. In addition, Ecova's "Consolidated Fixed Charge Coverage Ratio" (as defined in the credit agreement) must be greater than 1.50 to 1.00 as of the last day of any fiscal quarter. As of September 30, 2013, Ecova was in compliance with all of its covenants and based on the Consolidated Total Funded Debt to EBITDA Ratio, Ecova could borrow an additional $31.5 million and still be compliant with the covenants. The covenant restrictions are calculated on a rolling twelve month basis, so this additional borrowing capacity could increase or decrease or Ecova could be required to pay down the outstanding debt as future results change.

Ecova Redeemable Stock

Ecova's amended employee stock incentive plan provides an annual window at which time holders of common stock can put their shares back to Ecova, providing the shares are held for a minimum of six months. Stock is reacquired at fair market value, less the strike price, at the date of reacquisition. The value of the redeemable noncontrolling interests in Ecova associated with redeemable stock options and other outstanding redeemable stock was $8.3 million at September 30, 2013, an increase from $4.9 million at December 31, 2012. Options are valued at their maximum redemption amount which is equal to their intrinsic value (fair value less exercise price). During the nine months ended September 30, 2013, the estimated fair value of Ecova common stock increased such that it is higher compared to the exercise price of the options which increased the overall value of the redeemable noncontrolling interests to their current value. In 2009, the Ecova employee stock incentive plan was amended such that, on a prospective basis, not all options granted under the plan have the put right.

Off-Balance Sheet Arrangements

As of September 30, 2013, we had $28.0 million in letters of credit outstanding under our $400 million committed line of credit, compared to $35.9 million as of December 31, 2012.

Pension Plan

In the nine months ended September 30, 2013 we contributed $44.0 million to the pension plan (with no further contributions planned for the remainder of 2013). We expect to contribute a total of $62.0 million to the pension plan in the period 2014 to 2016, with contributions of $32.0 million in 2014, $20.0 million in 2015, and $10.0 million in 2016. Our contributions are expected to decrease during the period 2014 to 2016 from the previous estimate of $104.5 million due to an increase in the discount rate and greater than expected returns on fund assets which has caused us to become closer to fully funded status. 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 will be 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 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 have 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 annuity 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.

Credit Ratings

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

The following table summarizes our credit ratings as of November 7, 2013:

	Standard & Poor’s (1)	Moody’s (2)
Corporate/Issuer rating	BBB	Baa2
Senior secured debt	A-	A3
Senior unsecured debt	BBB	Baa2

(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 is restricted by provisions of certain covenants applicable to preferred stock (when outstanding) contained in our Restated Articles of Incorporation, as amended.

On August 9, 2013, Avista Corp.’s Board of Directors declared a quarterly dividend of $0.305 per share on the Company’s common stock, which was equal to the previous quarter's dividend.

Contractual Obligations

Our future contractual obligations have not materially changed except for the following during the nine months ended September 30, 2013. See the 2012 Form 10-K.

In August 2013, we entered into a $90.0 million term loan agreement with an institutional investor bearing an annual interest rate of 0.84 percent and maturing in 2016.

As of September 30, 2013, we expect to contribute a total of $62.0 million to the pension plan in the period 2014 to 2016, with contributions of $32.0 million in 2014, $20.0 million in 2015, and $10.0 million in 2016. The decrease in our expected contributions to $62.0 million during the period 2014 to 2016 from the previous estimate of $104.5 million is primarily due to an increase in the discount rate and greater than expected returns on fund assets which has caused us to become closer to fully funded status.

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 firm; or other independent sources. While we believe that these sources are reliable, we have not independently verified such data and can make no representation as to its accuracy. However, due to the Federal Government shutdown in the fourth quarter of 2013, employment data for September was not available; therefore, August employment results are reported instead.

We track multiple economic indicators affecting three distinct metropolitan areas in our service area: Spokane, Washington; Coeur d'Alene, Idaho; and Medford, Oregon. Several key indicators are employment change, unemployment rates, and foreclosure rates. On a year-over-year basis, August 2013 showed stronger job growth in Spokane and Coeur d'Alene, and lower unemployment rates in all three metropolitan areas. Foreclosure rates were below the U.S rate in the Coeur d'Alene and Medford areas. Unemployment rates are still above the national average; however, two key leading indicators, regional initial unemployment claims and residential building permits, continue to signal moderate growth over the next 12 months. Therefore, in 2013, we continue to expect economic growth in our service area to be no higher than the U.S. as a whole.

Seasonally adjusted nonfarm employment in our eastern Washington, northern Idaho, and southwestern Oregon metropolitan service areas exhibited mixed growth between August 2012 and August 2013. In Spokane, Washington, employment growth was 3.6 percent with gains in construction; education and health services; and other services. Employment increased by 4.3 percent in Coeur d'Alene, Idaho, with gains in manufacturing; other services; and government. In Medford, Oregon, employment decreased 0.3 percent, with gains in manufacturing and leisure and hospitality being offset by employment reductions in mining and logging; construction; financial activities; professional and business services; other services; and government. In contrast, year-over-year U.S. nonfarm sector jobs grew by 1.6 percent in August.

Unemployment rates (seasonally adjusted) went down in August 2013 from the year earlier in Spokane, Coeur d'Alene, and Medford. In Spokane the rate was 8.6 percent in August 2012 and declined to 7.7 percent in August 2013; in Coeur d'Alene the rate declined from 8.4 percent to 7.7 percent; and in Medford the rate declined from 10.8 percent to 9.8 percent. The U.S. rate declined from 8.1 percent to 7.3 percent in the same period.

The housing market in our Idaho and Oregon service areas continue to experience foreclosure rates lower than the national average. The September 2013 national rate was 0.1 percent, compared to 0.02 percent in Kootenai County (Coeur d'Alene), Idaho; and 0.02 percent in Jackson County (Medford), Oregon. The rate for Spokane County, Washington was comparable to the national rate at 0.1 percent.

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, 2013. See the 2012 Form 10-K.

Clean Air Act

The Clean Air Act currently requires a Title V operating permit for the Coyote Springs 2 Generation Facility. A renewal of this permit was issued on June 1, 2013 and will expire June 1, 2018.

Federal Regulatory Actions

In June 2013, President Obama released his Climate Action Plan which reiterates the goal of reducing greenhouse gas emissions in the U.S. "in the range of" 17 percent below 2005 levels by 2020 through such actions as regulating power plant emissions, promoting increased use of renewables and clean energy technology, and establishing tighter energy efficiency standards. In keeping with a Presidential Memorandum also issued June 25, 2013 the EPA issued a new proposal to limit carbon dioxide emissions from new coal-fired and natural gas-fueled electrical generating units on September 20, 2013. The Presidential Memorandum also directs the EPA to issue a final rule in a timely fashion thereafter, and to issue proposed standards for existing plants by June 1, 2014 with a final rule by June 1, 2015. The EPA was further directed to require that states develop implementation plans for existing plants by June 2016. Regulation of existing plants could have a significant impact depending on the structure and stringency of the final rule and the state implementation plans. The Administration's recent increase in its estimate of the "social cost of carbon" (which is used to calculate benefits associated with proposed regulations in certain regulatory contexts) to $38 per metric ton in 2015 (from the prior estimate of $23.80), may also lead to more costly regulatory requirements. Additionally, the Climate Action Plan requirements related to preparing the U.S. for the impacts of climate change could affect the Company and others in the industry as transmission system modifications to improve resiliency may be needed in order to meet those requirements.

State Legislation and State Regulatory Activities

During its 2013 Regular Session, the Washington State Legislature, under Engrossed Second Substitute Senate Bill 5802, created the Climate Legislative and Executive Workgroup. The Workgroup is charged with recommending a state program of actions and policies to reduce greenhouse gas (GHG) emissions, that if implemented would ensure achievement of Washington State’s emissions reductions goals set in Chapter 70.235 by the 2008 legislature. Washington Governor Jay Inslee, who is part of the Workgroup, has mentioned in recent statements related to the Workgroup’s efforts the possibility of eliminating “coal by wire” into Washington State. While there is no specific legislative proposal or executive action that would prohibit Washington utilities from importing electricity generated by coal generation from outside the state, such actions could affect the Company and its operations. While we cannot predict the outcome of any such actions, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to these issues.

Other

For other environmental issues and other contingencies see “Note 11 of the Notes to Condensed Consolidated Financial Statements.”

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our primary market risk exposures are:

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

Commodity Price Risk

Our qualitative commodity price risk disclosures have not materially changed during the nine months ended September 30, 2013 . Please refer to the 2012 Form 10-K. The following table presents energy commodity derivative fair values as a net asset or (liability) as of September 30, 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	Financial	Physical	Financial
2013	$ (837)	$ (5,030)	$ (3,000)	$ (9,955)	$ 291	$ 4,439	$ (323)	$ 4,658
2014	(2,640)	(2,528)	(7,712)	(11,021)	369	8,693	(707)	1,763
2015	(2,830)	(2,309)	(2,920)	(11,748)	(50)	4,020	—	6,087
2016	(2,849)	—	(985)	(6,347)	(109)	3,057	—	2,269
2017	(2,682)	—	38	—	(168)	—	—	—
Thereafter	(3,637)	—	—	—	(423)	—	—	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2012 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	Financial	Physical	Financial
2013	$ (5,165)	$ (26,360)	$ (20,085)	$ (17,560)	$ 154	$ 21,423	$ (709)	$ 13,218
2014	(3,745)	(1,664)	(6,384)	(5,390)	310	6,721	(1,125)	(434)
2015	(2,890)	(273)	(1,684)	389	(136)	116	—	(227)
2016	(2,644)	—	(270)	72	(194)	—	—	—
2017	(2,293)	—	—	—	(323)	—	—	—
Thereafter	(2,396)	—	—	—	(753)	—	—	—

(1) Physical transactions represent commodity transactions where we will take 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 above electric and natural gas derivative contracts 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, 2013 . See the 2012 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 2012 Form 10-K contains a discussion of risk management policies and procedures.

Interest Rate Risk

Our qualitative interest rate risk disclosures have not materially changed during the nine months ended September 30, 2013. See the 2012 Form 10-K.

As of September 30, 2013, we had interest rate swap agreements with a total notional amount of $165.0 million with mandatory cash settlement dates of October 2014, October 2015, October 2016 and June 2018 (which we entered into in June 2012, April 2013 and August 2013).

As of September 30, 2013, we had a long-term derivative asset of $25.2 million and a long-term derivative liability of $0.5 million, with an offsetting regulatory liability and regulatory asset, respectively on the Condensed Consolidated Balance Sheets in accordance with regulatory accounting practices.

As of December 31, 2012, we had interest rate swap agreements with a total notional amount of $160.0 million and current derivative liability of $1.4 million and a long-term derivative asset of $7.3 million with an offsetting regulatory asset and regulatory liability on the Condensed Consolidated Balance Sheets in accordance with regulatory accounting practices.

In anticipation of issuing long-term debt in 2018, we entered into an interest rate swap agreement in October 2013, with a notional amount of $25.0 million and a mandatory cash settlement date of June 2018.

Foreign Currency Risk

Our qualitative foreign currency risk disclosures have not materially changed during the nine months ended September 30, 2013. See the 2012 Form 10-K. As of September 30, 2013, we had a current derivative asset for foreign currency hedges of less than $0.1 million included in other current assets on the Condensed Consolidated Balance Sheet. As of September 30, 2013, we had entered into 14 Canadian currency forward contracts with a notional amount of $1.9 million ($1.9 million Canadian). As of December 31, 2012, we had entered into 20 Canadian currency forward contracts with a notional amount of $12.6 million ($12.5 million Canadian) with current derivative liability of less than $0.1 million.

Further information for derivatives and fair values is disclosed at "Note 5 of the Notes to Condensed Consolidated Financial Statements" and "Note 9 of the Notes to Condensed Consolidated Financial Statements."

Item 4. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended) to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company's management, including its principal executive and principal financial officers as appropriate to allow timely decisions regarding required disclosure. Under the supervision and with the participation of the Company's management, including the Company's principal executive officer and principal financial officer, the Company evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives. Based upon the Company's evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures are effective at a reasonable assurance level as of September 30, 2013.

There have been no changes in the Company's internal control over financial reporting that occurred during the third quarter of 2013 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. Other Information

Item 1. Legal Proceedings

See "Note 11 of Notes to Condensed Consolidated Financial Statements" in "Part I. Financial Information Item 1. Condensed Consolidated Financial Statements."

Item 1A. Risk Factors

Please refer to the 2012 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 2012 Form 10-K. In addition to these risk factors, see also "Forward-Looking Statements" for additional factors which could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

Item 4. Mine Safety Disclosures

Not applicable.

Item 6. Exhibits

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, 2013, 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 7, 2013

/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, 2013	Years Ended December 31 2012	2011	2010	2009	2008
Fixed charges, as defined:						
Interest charges	$ 56,630	$ 73,633	$ 69,591	$ 72,010	$ 61,361	$ 74,914
Amortization of debt expense and premium - net	2,841	3,803	4,617	4,414	5,673	4,673
Interest portion of rentals	1,945	2,717	2,154	2,027	1,874	1,601
Total fixed charges	$ 61,416	$ 80,153	$ 76,362	$ 78,451	$ 68,908	$ 81,188
Earnings, as defined:						
Pre-tax income from continuing operations	$ 126,869	$ 120,061	$ 160,171	$ 146,105	$ 134,971	$ 120,382
Add (deduct):						
Capitalized interest	(2,702)	(2,401)	(2,942)	(298)	(545)	(4,612)
Total fixed charges above	61,416	80,153	76,362	78,451	68,908	81,188
Total earnings	$ 185,583	$ 197,813	$ 233,591	$ 224,258	$ 203,334	$ 196,958
Ratio of earnings to fixed charges	3.02	2.47	3.06	2.86	2.95	2.43

Exhibit 15

November 7, 2013

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, 2013 and 2012, as indicated in our report dated November 7, 2013; because we did not perform an audit, we expressed no opinion on that information.

We are aware that our report referred to above, which is included in your Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, 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; and in Registration Statement Nos. 333 -187306 and 333-177981 on Form S-3.

We are also aware that the aforementioned report, pursuant to Rule 436(c) under the Securities Act of 1933, is not considered a part of the Registration Statement 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 7, 2013

/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 7, 2013

/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, 2013 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 7, 2013

/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