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, 2012

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 **(State or other jurisdiction of incorporation or organization)**	**91-0462470** **(I.R.S. Employer Identification No.)**
1411 East Mission Avenue, Spokane, Washington **(Address of principal executive offices)**	**99202-2600** **(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, 2012, 59,763,977 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, 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) and their effects on energy demand and electric generation, including the effect of precipitation and temperatures on the availability of hydroelectric resources, the effect of wind patterns on the availability of wind resources, the effect of temperatures on customer demand, and similar impacts on supply and demand in the wholesale energy markets;
- the effect of state and federal regulatory decisions on our ability to recover costs and earn a reasonable return including, but not limited to, the disallowance of costs and investments, and delay in the recovery of capital investments and operating costs;
- changes in wholesale energy prices that can affect, among other things, the cash requirements to purchase electricity and natural gas, the value received for sales in the wholesale energy market, the necessity to request changes in rates that are subject to regulatory approval, collateral required of us by counterparties on wholesale energy transactions and credit risk to us from such transactions, and the market value of derivative assets and liabilities;
- economic conditions in our service areas, including the effect on the demand for, and customers’ payment for, our utility services;
- global financial and economic conditions (including the impact on capital markets) and their effect on our ability to obtain funding at a reasonable cost;
- 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;
- the potential effects of legislation or administrative rulemaking, including the possible adoption of national or state laws requiring our resources to meet certain standards and placing 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 plan, which can affect future funding obligations, pension expense and pension 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;
- unplanned outages at any of our generating facilities or the inability of facilities to operate as intended;
- 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, but not limited to, alternative energy sources, suppliers and delivery arrangements;
- the ability to comply with the terms of the licenses for our hydroelectric generating facilities at cost-effective levels;
- 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, or mechanical breakdowns that may occur while operating and maintaining our generation, transmission and distribution systems;
- public injuries or damages arising from or allegedly arising from our operations
- blackouts or disruptions of interconnected transmission systems;
- disruption to information systems, automated controls and other technologies that we rely on for operations, communications and customer service;

- the potential for terrorist attacks, cyber security attacks or other malicious acts, that cause damage to our utility assets, as well as the national economy in general; including the impact of acts of terrorism, cyber security 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 other reasons that impair our ability to complete these projects in a timely and effective manner;
- changes in the long-term climate of the Pacific Northwest, 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 the loss of 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 and counterparties;
- the effect of any potential decline in our credit ratings, including impeded access to capital markets, higher interest costs, and certain covenants with ratings triggers 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, 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, among other things, costly litigation and 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.

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CONDENSED CONSOLIDATED STATEMENTS OF INCOME
Avista Corporation

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

	2012	2011
Operating Revenues:		
Utility revenues	$292,085	$301,551
Non-utility revenues	48,547	42,159
Total operating revenues	340,632	343,710
Operating Expenses:		
Utility operating expenses:		
Resource costs	153,801	171,393
Other operating expenses	64,449	60,579
Depreciation and amortization	28,255	26,341
Taxes other than income taxes	18,090	16,829
Non-utility operating expenses:		
Other operating expenses	42,647	31,726
Depreciation and amortization	3,391	1,964
Total operating expenses	310,633	308,832
Income from operations	29,999	34,878
Interest expense	19,128	18,703
Interest expense to affiliated trusts	136	152
Capitalized interest	(644)	(957)
Other expense-net	3,809	1,626
Income before income taxes	7,570	15,354
Income tax expense	1,608	3,717
Net income	5,962	11,637
Net income attributable to noncontrolling interests	(176)	(935)
Net income attributable to Avista Corporation	$ 5,786	$ 10,702
Weighted-average common shares outstanding (thousands), basic	59,047	58,057
Weighted-average common shares outstanding (thousands), diluted	59,123	58,232
Earnings per common share attributable to Avista Corporation:		
Basic	$ 0.10	$ 0.18
Diluted	$ 0.10	$ 0.18
Dividends paid per common share	$ 0.29	$ 0.275

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED STATEMENTS OF INCOME
Avista Corporation

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

	2012	2011
Operating Revenues:		
Utility revenues	$ 990,860	$1,059,221
Non-utility revenues	145,614	121,632
Total operating revenues	1,136,474	1,180,853
Operating Expenses:		
Utility operating expenses:		
Resource costs	500,805	575,290
Other operating expenses	191,407	188,961
Depreciation and amortization	83,327	78,600
Taxes other than income taxes	63,622	61,521
Non-utility operating expenses:		
Other operating expenses	130,327	95,581
Depreciation and amortization	9,966	5,673
Total operating expenses	979,454	1,005,626
Income from operations	157,020	175,227
Interest expense	57,453	55,415
Interest expense to affiliated trusts	413	455
Capitalized interest	(1,765)	(2,209)
Other expense-net	5,106	3,061
Income before income taxes	95,813	118,505
Income tax expense	33,106	40,937
Net income	62,707	77,568
Net income attributable to noncontrolling interests	(355)	(1,947)
Net income attributable to Avista Corporation	$ 62,352	$ 75,621
Weighted-average common shares outstanding (thousands), basic	58,778	57,731
Weighted-average common shares outstanding (thousands), diluted	59,026	57,934
Earnings per common share attributable to Avista Corporation:		
Basic	$ 1.06	$ 1.31
Diluted	$ 1.06	$ 1.30
Dividends paid per common share	$ 0.87	$ 0.825

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)

	2012	2011
Net income	$5,962	$11,637
Other Comprehensive Income:		
Unrealized investment gains - net of taxes of $68	110	—
Reclassification adjustment for realized gains on investment securities included in net income - net of taxes of $(11)	(17)	—
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $90 and $66, respectively	168	123
Total other comprehensive income	261	123
Comprehensive income	6,223	11,760
Comprehensive income attributable to noncontrolling interests	(176)	(935)
Comprehensive income attributable to Avista Corporation	$6,047	$10,825

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

	2012	2011
Net income	$62,707	$77,568
Other Comprehensive Income (Loss):		
Unrealized investment gains - net of taxes of $244	409	—
Reclassification adjustment for realized gains on investment securities included in net income - net of taxes of $(94)	(158)	—
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $263 and $(7), respectively	489	(13)
Total other comprehensive income (loss)	740	(13)
Comprehensive income	63,447	77,555
Comprehensive income attributable to noncontrolling interests	(355)	(1,947)
Comprehensive income attributable to Avista Corporation	$63,092	$75,608

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands

(Unaudited)

	September 30, 2012	December 31, 2011
Assets:		
Current Assets:		
Cash and cash equivalents	$ 82,952	$ 74,662
Accounts and notes receivable-less allowances of $44,354 and $43,958	141,659	203,452
Utility energy commodity derivative assets	1,678	1,139
Regulatory asset for utility derivatives	41,251	69,685
Investments and funds held for clients	114,226	118,536
Materials and supplies, fuel stock and natural gas stored	51,066	52,006
Deferred income taxes	35,792	30,473
Income taxes receivable	15,907	15,378
Other current assets	31,785	49,225
Total current assets	516,316	614,556
Net Utility Property:		
Utility plant in service	3,994,743	3,887,384
Construction work in progress	116,624	79,322
Total	4,111,367	3,966,706
Less: Accumulated depreciation and amortization	1,170,845	1,105,930
Total net utility property	2,940,522	2,860,776
Other Non-current Assets:		
Investment in exchange power-net	16,946	18,783
Investment in affiliated trusts	11,547	11,547
Goodwill	73,783	39,045
Long-term energy contract receivable of Spokane Energy	54,740	62,525
Other intangibles, property and investments-net	92,956	80,309
Total other non-current assets	249,972	212,209
Deferred Charges:		
Regulatory assets for deferred income tax	76,616	84,576
Regulatory assets for pensions and other postretirement benefits	248,082	260,359
Other regulatory assets	102,998	119,738
Non-current utility energy commodity derivative assets	1,073	185
Non-current regulatory asset for utility derivatives	30,111	40,345
Other deferred charges	24,566	21,787
Total deferred charges	483,446	526,990
Total assets	$4,190,256	$4,214,531

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED BALANCE SHEETS (continued)
Avista Corporation

Dollars in thousands
(Unaudited)

	September 30, 2012	December 31, 2011
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 140,536	$ 166,954
Client fund obligations	113,614	118,325
Current portion of long-term debt	392	7,474
Current portion of nonrecourse long-term debt of Spokane Energy	14,631	13,668
Short-term borrowings	82,000	96,000
Utility energy commodity derivative liabilities	35,788	70,824
Natural gas deferrals	13,169	12,140
Other current liabilities	147,723	141,789
Total current liabilities	547,853	627,174
Long-term debt	1,148,047	1,169,826
Nonrecourse long-term debt of Spokane Energy	21,688	32,803
Long-term debt to affiliated trusts	51,547	51,547
Long-term borrowings under committed line of credit	58,000	—
Regulatory liability for utility plant retirement costs	231,497	227,282
Pensions and other postretirement benefits	214,838	246,177
Deferred income taxes	527,397	505,954
Other non-current liabilities and deferred credits	105,481	116,084
Total liabilities	2,906,348	2,976,847
Commitments and Contingencies (See Notes to Condensed Consolidated Financial Statements)		
Redeemable Noncontrolling Interests	6,726	51,809
Equity:		
Avista Corporation Stockholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 59,754,870 and 58,422,781 shares outstanding	887,530	855,188
Accumulated other comprehensive loss	(4,897)	(5,637)
Retained earnings	377,111	336,150
Total Avista Corporation stockholders' equity	1,259,744	1,185,701
Noncontrolling Interests	17,438	174
Total equity	1,277,182	1,185,875
Total liabilities and equity	$4,190,256	$4,214,531

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)

	2012	2011
Operating Activities:		
Net income	$ 62,707	$ 77,568
Non-cash items included in net income:		
Depreciation and amortization	93,293	84,273
Provision for deferred income taxes	18,380	30,783
Power and natural gas cost amortizations, net	10,418	9,470
Amortization of debt expense and premium	2,876	3,186
Equity-related AFUDC	(2,875)	(1,655)
Other	52,859	32,958
Contributions to defined benefit pension plan	(44,000)	(26,000)
Changes in working capital components:		
Accounts and notes receivable	61,106	76,285
Materials and supplies, fuel stock and natural gas stored	941	(16,260)
Other current assets	7,209	(28,167)
Accounts payable	(10,783)	(11,994)
Other current liabilities	5,277	9,977
Net cash provided by operating activities	257,408	240,424
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(178,440)	(169,598)
Other capital expenditures	(3,908)	(2,730)
Federal grant payments received	5,902	13,398
Cash paid by subsidiaries for acquisitions, net of cash received	(50,310)	(199)
Decrease (increase) in funds held for clients	(9,599)	43,321
Purchase of securities available for sale	(88,843)	(47,299)
Sale and maturity of securities available for sale	103,545	—
Other	(7,412)	(4,604)
Net cash used in investing activities	(229,065)	(167,711)
Financing Activities:		
Net increase (decrease) in short-term borrowings	21,000	(13,500)
Borrowings from Ecova line of credit	28,000	—
Repayment of borrowings from Ecova line of credit	(5,000)	—
Redemption and maturity of long-term debt	(11,363)	(204)
Maturity of nonrecourse long-term debt of Spokane Energy	(10,153)	(9,258)
Long-term debt and short-term borrowing issuance costs	(177)	(2,362)
Cash paid for settlement of interest rate swap agreements	(18,547)	(10,557)
Issuance of common stock	28,699	21,216
Cash dividends paid	(51,215)	(47,685)
Purchase of subsidiary noncontrolling interest	(917)	(6,179)
Increase (decrease) in client fund obligations	(5,220)	3,978
Issuance of subsidiary noncontrolling interests	3,714	—
Other	1,126	528
Net cash used in financing activities	(20,053)	(64,023)
Net increase in cash and cash equivalents	8,290	8,690
Cash and cash equivalents at beginning of period	74,662	69,413
Cash and cash equivalents at end of period	$ 82,952	$ 78,103
Supplemental Cash Flow Information:		
Cash paid during the period:		
Interest	$ 43,487	$ 41,582
Income taxes	12,527	24,506
Non-cash financing and investing activities:		
Accounts payable for capital expenditures	3,556	2,642
Redeemable noncontrolling interests	(8,274)	5,147

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
AND REDEEMABLE NONCONTROLLING INTERESTS
Avista Corporation

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

	2012	2011
Common Stock, Shares:		
Shares outstanding at beginning of period	58,422,781	57,119,723
Issuance of common stock	1,332,089	1,081,274
Shares outstanding at end of period	59,754,870	58,200,997
Common Stock, Amount:		
Balance at beginning of period	$ 855,188	$ 827,592
Equity compensation expense	3,354	2,718
Issuance of common stock, net of issuance costs	28,699	21,216
Equity transactions of consolidated subsidiaries	289	(2,817)
Balance at end of period	887,530	848,709
Accumulated Other Comprehensive Loss:		
Balance at beginning of period	(5,637)	(4,326)
Other comprehensive income (loss)	740	(13)
Balance at end of period	(4,897)	(4,339)
Retained Earnings:		
Balance at beginning of period	336,150	302,518
Net income attributable to Avista Corporation	62,352	75,621
Cash dividends paid (common stock)	(51,215)	(47,685)
Expiration of subsidiary noncontrolling interests redemption rights	23,805	—
Valuation adjustments and other noncontrolling interests activity	6,019	(3,906)
Balance at end of period	377,111	326,548
Total Avista Corporation stockholders’ equity	1,259,744	1,170,918
Noncontrolling Interests:		
Balance at beginning of period	174	(600)
Net income attributable to noncontrolling interests	234	95
Deconsolidation of variable interest entity	(673)	—
Purchase of subsidiary noncontrolling interests	(117)	—
Expiration of subsidiary noncontrolling interests redemption rights	17,790	—
Other	30	(25)
Balance at end of period	17,438	(530)
Total equity	$ 1,277,182	$ 1,170,388
Redeemable Noncontrolling Interests:		
Balance at beginning of period	$ 51,809	$ 46,722
Net income attributable to noncontrolling interests	121	1,852
Issuance of subsidiary noncontrolling interests	3,714	—
Purchase of subsidiary noncontrolling interests	(784)	(6,179)
Expiration of subsidiary noncontrolling interests redemption rights	(41,595)	—
Valuation adjustments and other noncontrolling interests activity	(6,539)	9,675
Balance at end of period	$ 6,726	$ 52,070

The Accompanying Notes are an Integral Part of These Statements.

AVISTA CORPORATION

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, 2012 and 2011 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, 2011 (2011 Form 10-K). Please refer to the section "Acronyms and Terms" in the 2011 Form 10-K for definitions of terms. The acronyms and terms are an integral part of these condensed consolidated financial statements.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corp. is an energy company engaged in the generation, transmission and distribution of 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 and northern Idaho. In addition, Avista Utilities has electric generating facilities in Montana and northern Oregon. Avista Utilities also provides natural gas distribution service in parts of eastern Washington and northern Idaho, as well as parts of northeast and southwest 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 79.0 percent owned subsidiary as of September 30, 2012. 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,	
	2012	2011	2012	2011
Utility taxes	$ 10,741	$ 10,270	$ 41,353	$ 41,551

Other Expense - Net

Other 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,	
	2012	2011	2012	2011
Interest income	$ (166)	$ (455)	$ (804)	$ (1,029)
Interest on regulatory deferrals	(19)	(15)	(43)	(83)
Equity-related AFUDC	(1,127)	(421)	(2,875)	(1,655)
Net loss on investments	2,430	560	2,957	597
Other expense	2,877	1,957	7,040	5,466
Other income	(186)	—	(1,169)	(235)
Total	$ 3,809	$ 1,626	$ 5,106	$ 3,061

Included in net loss on investments for the three months and nine months ended September 30, 2012 are impairment losses of $2.4 million related to the impairment of the Company's investment in a fuel cell business and the write-off of the Company's investment in a solar energy company.

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 and investment securities classified as available for sale. Investments and funds held for clients as of September 30, 2012 are as follows (dollars in thousands):

	Amortized Cost	Unrealized Gain	Fair Value
Cash and cash equivalents	$ 31,874	$ —	$ 31,874
Securities available for sale:			
U.S. government agency	63,207	251	63,458
Municipal	5,049	133	5,182
Corporate fixed income – financial	6,544	90	6,634
Corporate fixed income – industrial	4,905	94	4,999
Corporate fixed income – utility	1,035	33	1,068
Certificates of deposit	1,000	11	1,011
Total securities available for sale	81,740	612	82,352
Total investments and funds held for clients	$113,614	$ 612	$114,226

Investments and funds held for clients as of December 31, 2011 were as follows (dollars in thousands):

	Amortized Cost	Unrealized Gain (Loss)	Fair Value
Cash and cash equivalents	$ 21,957	$ —	$ 21,957
Securities available for sale:			
U.S. government agency	74,721	172	74,893
Municipal	425	—	425
Corporate fixed income – financial	11,139	15	11,154
Corporate fixed income – industrial	6,495	23	6,518
Corporate fixed income – utility	2,088	4	2,092
Certificates of deposit	1,500	(3)	1,497
Total securities available for sale	96,368	211	96,579
Total investments and funds held for clients	$118,325	$ 211	$118,536

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. Approximately 93 percent and 88 percent of the investment portfolio was rated AA or higher as of September 30, 2012 and December 31, 2011, respectively, by nationally recognized statistical rating organizations. All fixed income securities were rated at least investment grade as of September 30, 2012 and December 31, 2011.

Proceeds from sales, maturities and calls of securities available for sale were $103.5 million for the nine months ended September 30, 2012 with gross realized gains of $0.3 million and there were not any gross realized losses. Proceeds from sales, maturities and calls of securities available for sale were $32.0 million for the three months ended September 30, 2012 with gross realized gains of $0.1 million and there were not any gross realized losses. There were no sales, maturities and calls of securities available for sale during the first nine months of 2011.

Contractual maturities of securities available for sale (at fair value) as of September 30, 2012 and December 31, 2011 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, 2012	$ 2,455	$ 17,109	$ 55,789	$ 6,999	$82,352
December 31, 2011	425	55,126	41,028	—	96,579

Actual maturities may differ due to call or prepayment rights and the effective duration was 1.8 years as of September 30, 2012 and 1.3 years as of December 31, 2011.

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 November 30, 2011 for the other businesses and as of December 31, 2011 for Ecova 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, 2011	$33,799	$12,979	$ (7,733)	$39,045
Goodwill acquired during the period	33,484	—	—	33,484
Adjustments	1,254	—	—	1,254
Balance as of the September 30, 2012	$68,537	$12,979	$ (7,733)	$73,783

Accumulated impairment losses are attributable to the other businesses. The goodwill acquired in 2012 was related to Ecova's acquisition of LPB Energy Management (LPB) effective January 31, 2012. The adjustment to goodwill recorded represents purchase accounting adjustments for Ecova's acquisition of Prenova based upon further review of the fair market values of relevant assets and liabilities identified as of the acquisition date.

Other Intangibles

Other Intangibles represent the amounts assigned to client relationships related to the Ecova acquisition of Cadence Network in 2008 (estimated amortization period of 12 years), Ecos in 2009 (estimated amortization period of 3 years), Loyalton in 2010 (estimated amortization period of 6 years), Prenova in 2011 (estimated amortization period of 9 years) and LPB in 2012 (estimated amortization period of 3 to 10 years), software development costs (estimated amortization period of 3 to 7 years) and other. Other Intangibles are included in other intangibles, property and investments - net on the Condensed Consolidated Balance Sheets. Amortization expense related to Other Intangibles was as follows for the three and nine months ended September 30 (dollars in thousands):

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Other intangible amortization	$ 2,436	$ 1,145	$ 7,091	$ 3,298

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

	2012	2013	2014	2015	2016
Estimated amortization expense	$2,268	$8,899	$7,929	$5,633	$4,687

The gross carrying amount and accumulated amortization of Other Intangibles as of September 30, 2012 and December 31, 2011 are as follows (dollars in thousands):

	September 30, 2012	December 31, 2011
Client relationships	$ 32,959	$ 18,859
Software development costs	32,935	29,327
Other	5,672	3,065
Total other intangibles	71,566	51,251
Client relationships accumulated amortization	(6,871)	(3,623)
Software development costs accumulated amortization	(15,392)	(12,016)
Other accumulated amortization	(1,480)	(990)
Total accumulated amortization	(23,743)	(16,629)
Total other intangibles - net	$ 47,823	$ 34,622

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 derivatives depends on the intended use of the derivatives and the resulting designation.

The Washington Utilities and Transportation Commission (WUTC) 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 settlement. 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 settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rates cases. Regulatory assets are assessed regularly and are probable for recovery through future rates.

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

Fair Value Measurements

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

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses losses that do not meet these conditions for accrual, if there is a reasonable possibility that a loss may be incurred.

NOTE 2. NEW ACCOUNTING STANDARDS

Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) No. 2011-04, "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs." This ASU requires enhanced disclosures for fair value measurements, including quantitative analysis of unobservable inputs used in Level 3 fair value measurements. The ASU also clarifies the FASB's intent about the application of existing fair value measurement requirements. The adoption of this ASU did not have any impact on the Company's financial condition, results of operations and cash flows. See Note 9 for the Company's fair value disclosures.

In September 2011, the Financial Accounting Standards Board (FASB) issued ASU No. 2011-08, "Intangibles – Goodwill and Other (Topic 350): Testing Goodwill for Impairment." This ASU amends the guidance on testing goodwill for impairment, providing entities with the option of performing a qualitative assessment before calculating the fair value of the reporting unit. If it is determined, on the basis of the qualitative assessment, that the fair value of the reporting unit is more likely than not less than the carrying amount, the two-step impairment test would be required. This ASU does not change how goodwill is calculated or assigned to reporting units, nor does it revise the requirement to test goodwill annually for impairment. This ASU is effective for goodwill impairment tests performed for fiscal years beginning after December 15, 2011, with early adoption permitted. The Company does not expect that this ASU will have any material impact on its testing of goodwill for impairment.

NOTE 3. VARIABLE INTEREST ENTITIES

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 $325 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.

Ecova formed a partnership, SEEL, LLC (SEEL) with a third party for the purpose of entering into utility contracts to provide energy efficiency services. SEEL is funded 49 percent by Ecova and 51 percent by the third party. Prior to 2012, Ecova determined that it was the primary beneficiary of SEEL based on its management of the entity and its technical expertise in obtaining and fulfilling the utility contracts, and Ecova was obligated to absorb the losses or receive the benefits that could be significant to SEEL. In 2012, Ecova is no longer the primary beneficiary of SEEL because it is no longer the sole provider of the technical expertise necessary to obtain and fulfill utility contracts. As of January 1, 2012, Ecova uses the equity method to account for its arrangement with SEEL.

NOTE 4. REDEEMABLE NONCONTROLLING INTERESTS AND SUBSIDIARY ACQUISITIONS

The acquisition of Cadence Network in July 2008 was funded with the issuance of Ecova common stock. Under the transaction agreement, the previous owners of Cadence Network had a right to have their shares of Ecova common stock redeemed during July 2011 or July 2012 if their investment in Ecova was not liquidated through either an initial public offering or sale of the business to a third party. These redemption rights were not exercised and expired effective July 31, 2012. As such, this redeemable noncontrolling interest was reclassified to equity effective July 31, 2012. Additionally, 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. 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, 2012 and December 31, 2011 (dollars in thousands):

	September 30, 2012	December 31, 2011
Previous owners of Cadence Network	$ —	$ 38,893
Stock options and other outstanding redeemable stock	6,726	12,916
Total redeemable noncontrolling interests	$ 6,726	$ 51,809

On November 30, 2011, Ecova acquired Prenova, Inc. (Prenova), an Atlanta-based energy management company. The cash paid for the acquisition of Prenova of $35.6 million was funded primarily through borrowings under Ecova's committed credit agreement. The acquired assets and assumed liabilities of Prenova were recorded at their respective estimated fair values as of the date of acquisition. Final purchase accounting is pending the completion of further review of the fair market values of relevant assets and liabilities identified as of the acquisition date. The results of operations of Prenova are included in the condensed consolidated financial statements beginning December 1, 2011.

On January 31, 2012, Ecova acquired 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 certain 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. Assets recorded include the following: accounts receivable of $2.5 million, goodwill of $33.5 million, client backlog of $8.2 million (estimated amortization period of 3 years), client relationships of $4.8 million (estimated amortization period of 10 years) and internal use software of $2.5 million (estimated amortization period of 3 to 4 years). These intangible assets are included in other intangibles, property and investments on the Condensed Consolidated Balance Sheet. Final purchase accounting is pending the completion of further review of the fair market values of relevant assets and liabilities identified as of the acquisition date. The results of operations of LPB are included in the condensed consolidated financial statements beginning February 1, 2012. The sellers of LPB have the potential to receive additional purchase price payments of $0.5 million in 2012, $1.0 million in 2013 and $1.5 million in 2014. These payments are contingent upon reaching certain revenue thresholds for certain customer contracts. As of September 30, 2012, Ecova has recorded a contingent liability of $0.4 million based on management’s assessment of the probability of the revenue thresholds being achieved.

Pro forma disclosures reflecting the effects of Ecova’s acquisitions are not presented, as the acquisitions are not material to Avista Corp.’s condensed consolidated 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 its resource procurement and management operations in the electric business, Avista Utilities engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Utilities’ load obligations and the use of these resources to capture available economic value. Avista Utilities sells and purchases wholesale electric capacity and energy and fuel as part of the process of acquiring and balancing resources to serve its load obligations. These transactions range from terms of 30 minutes up to multiple years.

Avista Utilities makes continuing projections of:

- electric loads at various points in time (ranging from 30 minutes 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, Avista Utilities makes purchases and sales of electric capacity and energy and fuel to match expected resources to expected electric load requirements. 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.

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.

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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, 2012 that are expected to settle in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical MWH	Financial MWH	Physical mmBTUs	Financial mmBTUs	Physical MWH	Financial MWH	Physical mmBTUs	Financial mmBTUs
2012	766	711	8,726	30,181	126	488	2,642	29,878
2013	594	2,237	14,816	79,548	309	2,446	4,432	63,423
2014	397	620	6,316	51,359	409	1,697	1,786	29,587
2015	379	614	3,390	19,205	286	614	—	17,325
2016	366	—	1,365	455	287	—	—	—
Thereafter	949	—	—	—	730	—	—	—

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, 2012 and December 31, 2011 (dollars in thousands):

	September 30, 2012	December 31, 2011
Number of contracts	—	3
Notional amount	—	$ 75,000
Mandatory cash settlement date	—	July 2012
Number of contracts	2	2
Notional amount	$ 85,000	$ 85,000
Mandatory cash settlement date	June 2013	June 2013
Number of contracts	2	—
Notional amount	$ 50,000	—
Mandatory cash settlement date	October 2014	—
Number of contracts	1	—
Notional amount	$ 25,000	—
Mandatory cash settlement date	October 2015	—

In May 2012, the Company cash settled interest rate swap contracts (notional amount of $75.0 million) and paid a total of $18.5 million. The interest rate swap contracts were settled in connection with the pricing of $80.0 million of First Mortgage Bonds (see Note 8). Upon settlement of the 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 life of the forecasted interest payments.

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 economically 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, 2012 and December 31, 2011 (dollars in thousands):

	September 30, 2012	December 31, 2011
Number of contracts	30	28
Notional amount (in United States dollars)	$ 6,578	$ 7,033
Notional amount (in Canadian dollars)	$ 6,469	$ 7,192

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, 2012 (in thousands):

		Fair Value			
Derivative	Balance Sheet Location	Asset	Liability	Collateral Netting	Net Asset (Liability)
Foreign currency contracts	Other current liabilities	$ —	$ (30)	$ —	$ (30)
Interest rate contracts	Other current liabilities	—	(3,827)	—	(3,827)
Interest rate contracts	Other intangibles, property and investments - net	5,069	—	—	5,069
Commodity contracts	Current utility energy commodity derivative assets	1,857	(179)	—	1,678
Commodity contracts	Non-current utility energy commodity derivative assets	1,709	(636)	—	1,073
Commodity contracts	Current utility energy commodity derivative liabilities	46,879	(89,805)	7,138	(35,788)
Commodity contracts	Other non-current liabilities and deferred credits	26,616	(57,800)	2,336	(28,848)
Total derivative instruments recorded on the balance sheet		$82,130	$(152,277)	$ 9,474	$(60,673)

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of December 31, 2011 (in thousands):

		Fair Value		
Derivative	Balance Sheet Location	Asset	Liability	Net Asset (Liability)
Foreign currency contracts	Other current assets	$ 32	$ —	$ 32
Interest rate contracts	Other current liabilities	—	(16,253)	(16,253)
Interest rate contracts	Other non-current liabilities and deferred credits	—	(2,642)	(2,642)
Commodity contracts	Current utility energy commodity derivative assets	1,618	(479)	1,139
Commodity contracts	Non-current utility energy commodity derivative assets	185	—	185
Commodity contracts	Current utility energy commodity derivative liabilities	40,090	(110,914)	(70,824)
Commodity contracts	Other non-current liabilities and deferred credits	44,308	(84,838)	(40,530)
Total derivative instruments recorded on the balance sheet		$86,233	$(215,126)	$(128,893)

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, 2012, the Company had cash deposited as collateral of $15.0 million and letters of credit of $19.3 million outstanding related to its energy derivative contracts. The Consolidated Balance Sheet at September 30, 2012 reflects the offsetting of $9.5 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, 2012 was $115.8 million. If the credit-risk-related contingent features underlying these agreements were triggered on September 30, 2012, the Company could be required to post $32.5 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. The Company seeks to mitigate 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, 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 $26 million in cash to the pension plan in 2011. The Company contributed $44 million in cash to the pension plan in 2012 (with no further contributions planned for the remainder of 2012).

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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.

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

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

The Company uses a December 31 measurement date for its pension and other postretirement benefit plans. The following table sets forth the components of net periodic benefit costs for the three and nine months ended September 30 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2012	2011	2012	2011
Three months ended September 30:				
Service cost	$ 3,891	$ 3,303	$ 689	$ 433
Interest cost	6,084	6,017	1,256	1,005
Expected return on plan assets	(5,950)	(5,775)	(375)	(400)
Transition obligation recognition	—	—	125	125
Amortization of prior service cost	75	125	(37)	(37)
Net loss recognition	3,019	2,506	1,250	960
Net periodic benefit cost	$ 7,119	$ 6,176	$ 2,908	$ 2,086
Nine months ended September 30:				
Service cost	$ 11,573	$ 9,548	$ 2,067	$ 1,299
Interest cost	18,277	18,143	3,793	3,015
Expected return on plan assets	(17,900)	(17,141)	(1,125)	(1,200)
Transition obligation recognition	—	—	375	375
Amortization of prior service cost	225	369	(111)	(111)
Net loss recognition	8,797	6,909	3,814	2,634
Net periodic benefit cost	$ 20,972	$ 17,828	$ 8,813	$ 6,012

NOTE 7. SHORT-TERM BORROWINGS

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of 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, 2012, the Company was in compliance with this covenant.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under the Company's revolving committed lines of credit were as follows as of September 30, 2012 and December 31, 2011 (dollars in thousands):

	September 30, 2012	December 31, 2011
Balance outstanding at end of period	$ 82,000	$ 61,000
Letters of credit outstanding at end of period	$ 26,815	$ 29,030
Average interest rate at end of period	1.08%	1.12%

Ecova

In July 2012, Ecova entered into a new $125.0 million committed line of credit agreement with various financial institutions that replaced its $60.0 million committed line of credit agreement and has an expiration date of July 2017. The credit agreement is secured by substantially all of Ecova's assets. Balances outstanding and interest rates of borrowings under Ecova's credit agreements were as follows as of September 30, 2012 and December 31, 2011 (dollars in thousands):

	September 30, 2012	December 31, 2011
Balance outstanding at end of period	$ 58,000	$ 35,000
Average interest rate at end of period	2.49%	2.38%

As of September 30, 2012, borrowings under Ecova's committed line of credit were classified as long-term.

NOTE 8. LONG-TERM DEBT

The following details long-term debt outstanding as of September 30, 2012 and December 31, 2011 (dollars in thousands):

Maturity Year	Description	Interest Rate	September 30, 2012	December 31, 2011
2012	Secured Medium-Term Notes	7.37%	$ —	$ 7,000
2013	First Mortgage Bonds	1.68%	50,000	50,000
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
	Total secured long-term debt		1,256,700	1,263,700
2023	Unsecured Pollution Control Bonds	6.00%	—	4,100
	Other long-term debt and capital leases		5,192	5,455
	Settled interest rate swaps		(28,252)	(10,629)
	Unamortized debt discount		(1,501)	(1,626)
	Total		1,232,139	1,261,000
	Secured Pollution Control Bonds held by Avista Corporation (1) (2)		(83,700)	(83,700)
	Current portion of long-term debt		(392)	(7,474)
	Total long-term debt		$1,148,047	$1,169,826

(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.

In June 2012, Avista Corp. entered into a bond purchase agreement with certain institutional investors in the private placement market for the purpose of issuing $80.0 million of 4.23 percent First Mortgage Bonds due in 2047. The new First Mortgage Bonds will be issued under and in accordance with the Mortgage and Deed of Trust, dated as of June 1, 1939, from the Company to Citibank, N.A., trustee, as amended and supplemented by various supplemental indentures and other instruments. Issuance of the bonds will occur at closing in November 2012. Net total proceeds from the sale of the new bonds will be used to repay a portion of the borrowings outstanding under the Company's $400.0 million committed line of credit and for general corporate purposes.

Nonrecourse Long-Term Debt

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

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.

AVISTA CORPORATION

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, 2012 and December 31, 2011 (dollars in thousands):

	September 30, 2012		December 31, 2011	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$951,000	$1,164,223	$962,100	$1,135,536
Long-term debt (Level 3)	222,000	245,995	222,000	234,226
Nonrecourse long-term debt (Level 3)	36,319	39,336	46,471	51,974
Long-term debt to affiliated trusts (Level 3)	51,547	43,686	51,547	43,810

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information. The Company's publicly held long-term debt was classified as Level 2, as the fair value was determined utilizing observable inputs in non-active markets. The Company's other long-term debt (including long-term debt to affiliated trusts and nonrecourse long-term debt) was classified as Level 3, as certain inputs used to determine the fair value are unobservable. In particular, 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, 2012 and December 31, 2011 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, 2012					
Assets:					
Energy commodity derivatives	$ —	$ 76,695	$ —	$ (73,944)	$ 2,751
Level 3 energy commodity derivatives:					
Power exchange agreements	—	—	366	(366)	—
Interest rate swaps	—	5,069	—	—	5,069
Investments and funds held for clients:					
Cash and cash equivalents	31,874	—	—	—	31,874
Securities available for sale:					
U.S. government agency	—	63,458	—	—	63,458
Municipal	—	5,182	—	—	5,182
Corporate fixed income – financial	—	6,634	—	—	6,634
Corporate fixed income – industrial	—	4,999	—	—	4,999
Corporate fixed income – utility	—	1,068	—	—	1,068
Certificate of deposits	—	1,011	—	—	1,011
Funds held in trust account of Spokane Energy	1,600	—	—	—	1,600
Deferred compensation assets:					
Fixed income securities (2)	2,148	—	—	—	2,148
Equity securities (2)	5,814	—	—	—	5,814
Total	$41,436	$164,116	$ 366	$ (74,310)	$131,608
Liabilities:					
Energy commodity derivatives	$ —	$125,488	$ —	$ (83,418)	$ 42,070
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	3,105	—	3,105
Power exchange agreements	—	—	18,242	(366)	17,876
Power option agreements	—	—	1,585	—	1,585
Interest rate swaps	—	3,827	—	—	3,827
Foreign currency derivatives	—	30	—	—	30
Total	$ —	$129,345	$22,932	$ (83,784)	$ 68,493

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2011					
Assets:					
Energy commodity derivatives	$ —	$ 80,571	$ —	$ (79,247)	$ 1,324
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	956	(956)	—
Power exchange agreements	—	—	4,674	(4,674)	—
Foreign currency derivatives	—	32	—	—	32
Investments and funds held for clients:					
Cash and cash equivalents	21,957	—	—	—	21,957
Securities available for sale:					
U.S. government agency	—	74,893	—	—	74,893
Municipal	—	425	—	—	425
Corporate fixed income – financial	—	11,154	—	—	11,154
Corporate fixed income – industrial	—	6,518	—	—	6,518
Corporate fixed income – utility	—	2,092	—	—	2,092
Certificate of deposits	—	1,497	—	—	1,497
Funds held in trust account of Spokane Energy	1,600	—	—	—	1,600
Deferred compensation assets:					
Fixed income securities (2)	2,116	—	—	—	2,116
Equity securities (2)	5,252	—	—	—	5,252
Total	$30,925	$177,182	$ 5,630	$ (84,877)	$128,860
Liabilities:					
Energy commodity derivatives	$ —	$177,743	$ —	$ (79,247)	$ 98,496
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	2,644	(956)	1,688
Power exchange agreements	—	—	14,584	(4,674)	9,910
Power option agreements	—	—	1,260	—	1,260
Interest rate swaps	—	18,895	—	—	18,895
Total	$ —	$196,638	$18,488	$ (84,877)	$130,249

(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 intangibles, property and investments-net on the Condensed Consolidated Balance Sheets.

Avista Utilities 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 Utilities' 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) the Company uses a nationally recognized third party to obtain fair value and reviews these prices for accuracy using a variety of market tools and analysis. The Company's pricing vendor uses a generic model which uses standard inputs (listed in order of priority for use), including 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. Further, the model uses Option Adjusted Spread and is a multidimensional relational model. 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 $0.9 million as of September 30, 2012 and $1.3 million as of December 31, 2011.

Level 3 Fair Value

For power exchange agreements, 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 power commodity option agreements, 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 2012, and 3) volatility rates for periods beyond October 2015. 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 natural gas commodity exchange agreements, the Company uses the same Level 2 brokered quotes described above; however, the Company also estimates the purchase and sales volumes (within contractual limits) as well as the timing of those transactions. Changing the timing of volume estimates changes the timing of purchases and sales, impacting which brokered quote is used. Because the brokered quotes can vary significantly from period to period, the unobservable estimates of the timing and volume of transactions can have a significant impact on the calculated fair value. The Company currently estimates volumes and timing of transactions based on a most likely scenario using historical data. Historically, the timing and volume of transactions have not been highly correlated with market prices and market volatility.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of September 30, 2012 (dollars in thousands):

	Fair Value (Net) at September 30, 2012	Valuation Technique	Unobservable Input	Range
Power exchange agreements	$ (17,876)	Surrogate facility pricing	O&M charges	$30.49 - $53.82/MWh (1)
			Escalation factor	5% - 2012 to 2015
				3% - 2016 to 2019
			Transaction volumes	361,630 - 379,156 MWhs
Power option agreements	(1,585)		Strike price	$41.84/MWh - 2012
		Black-Scholes-Merton		$78.21/MWh - 2019
			Delivery volumes	157,517 - 287,147 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreements	(3,105)	Internally derived weighted average cost of gas	Forward purchase prices	$3.53 - $3.69/mmBTU
			Forward sales prices	$3.70 - $4.65/mmBTU
			Purchase volumes	135,000 - 465,000 mmBTUs
			Sales volumes	140,010 - 310,000 mmBTUs

(1) The average O&M charges for 2012 were $40.87 per MWh.
(2) The estimated volatility rate of 0.20 is compared to actual known volatility rates of 0.34 for 2012 to 0.24 in October 2015.

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 net energy commodity derivative assets (liabilities) measured at fair value using significant unobservable inputs (Level 3) for the three and nine months ended September 30, 2012 and 2011 (dollars in thousands):

	Natural Gas Exchange Agreements	Power Exchange Agreements	Power Option Agreements	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	—	—	—	—
Issuances	—	—	—	—
Settlements	(1)	—	—	(1)
Transfers to other categories	—	—	—	—
Ending balance as of September 30, 2012	$ (3,105)	$ (17,876)	$ (1,585)	$ (22,566)
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	—	—	—	—
Issuances	—	—	—	—
Settlements	(1,053)	4,250	—	3,197
Transfers to other categories	—	—	—	—
Ending balance as of September 30, 2012	$ (3,105)	$ (17,876)	$ (1,585)	$ (22,566)
Three months ended September 30, 2011:				
Balance as of July 1, 2011	$ (4,404)	$ 13,058	$ (1,309)	$ 7,345
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	2,138	(8,962)	(281)	(7,105)
Purchases	—	—	—	—
Issuances	—	—	—	—
Settlements	—	—	—	—
Transfers to other categories	—	—	—	—
Ending balance as of September 30, 2011	$ (2,266)	$ 4,096	$ (1,590)	$ 240
Nine months ended September 30, 2011:				
Balance as of January 1, 2011	$ —	$ 15,793	$ (2,334)	$ 13,459
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	2,138	(13,642)	744	(10,760)
Purchases	—	—	—	—
Issuances	—	—	—	—
Settlements	—	1,945	—	1,945
Transfers to other categories	(4,404)	—	—	(4,404)
Ending balance as of September 30, 2011	$ (2,266)	$ 4,096	$ (1,590)	$ 240

(1) The WUTC 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 settlement. 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 settlement, 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

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corporation 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,	
	2012	2011	2012	2011
Numerator:				
Net income attributable to Avista Corporation	$ 5,786	$10,702	$62,352	$75,621
Noncontrolling earnings adjustment for dilutive securities	(16)	(170)	(25)	(340)
Adjusted net income attributable to Avista Corporation for computation of diluted earnings per common share	$ 5,770	$10,532	$62,327	$75,281
Denominator:				
Weighted-average number of common shares outstanding-basic	59,047	58,057	58,778	57,731
Effect of dilutive securities:				
Performance and restricted stock awards	71	131	234	149
Stock options	5	44	14	54
Weighted-average number of common shares outstanding-diluted	59,123	58,232	59,026	57,934
Earnings per common share attributable to Avista Corporation:				
Basic	$ 0.10	$ 0.18	$ 1.06	$ 1.31
Diluted	$ 0.10	$ 0.18	$ 1.06	$ 1.30

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. With respect to matters discussed in this Note relating to Avista Energy, any potential liabilities or refunds by Avista Energy remain the responsibility of Avista Corp. and/or its subsidiaries and were not assumed by the purchaser of Avista Energy's contracts and operations in 2007.

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). The Attorney General of the State of California (California AG), the California Electricity Oversight Board, and the City of Tacoma, Washington (City of Tacoma) challenged the FERC's decisions approving the Agreement in Resolution, which are now pending before the United States Court of Appeals for the Ninth Circuit (Ninth Circuit).

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. The CalISO continues to work on its compliance filing for the Refund Period, which will show "who owes what to whom." In July 2011, the FERC accepted the preparatory rerun compliance filings by the CalPX and CalISO, and responded to the CalPX request for guidance on issues related to completing the final determination of "who owes what to whom." The FERC directed both the CalISO and the CalPX to prepare and submit to the FERC their final refund rerun compliance filings. The FERC's order also directs the CalPX to pay past due principal amounts to governmental entities. In February 2012, the FERC denied the challenges made to the July 2011 order by the California AG, the CPUC, PG&E and SCE. As of September 30, 2012, 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.

Many of the orders that the FERC has issued in the California refund proceedings were appealed to the Ninth Circuit. In October 2004, the Ninth Circuit ordered that briefing proceed in two rounds. The first round was limited to three issues: (1) which parties are subject to the FERC's refund jurisdiction in light of the exemption for government-owned utilities in section 201(f) of the FPA; (2) the temporal scope of refunds under section 206 of the FPA; and (3) which categories of transactions are subject to refunds. The second round of issues and their corresponding briefing schedules have not yet been set by the Ninth Circuit.

In September 2005, the Ninth Circuit held that the FERC did not have the authority to order refunds for sales made by municipal utilities in the California refund proceeding. 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 reiterated that the California Parties are expected to be very specific when presenting their arguments and evidence, and that general claims would not suffice. 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 has one exchange transaction with the CalISO. 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 FERC on November 2, 2012. The California AG, the CPUC, PG&E and SCE also filed a petition for review of the May 2011 order with the Ninth Circuit. A FERC hearing commenced on April 11, 2012 and concluded on July 19, 2012. Post-hearing briefs were filed September 28, 2012, and reply briefs are due December 4, 2012. The initial decision is to be issued no later than February 15, 2013. On August 27, 2012, the Presiding Administrative Law Judge 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. The California Parties filed a brief on exceptions on September 26, 2012, and Avista Utilities filed a brief opposing exceptions on October 16, 2012. On November 2, 2012, 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, FERC also held that a market-wide remedy would not be appropriate with regard to any respondent during the Summer Period. 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.

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. 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 the 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 establishes an evidentiary, trial-type hearing before an Administrative Law Judge (ALJ), and reopens the record to permit parties to present evidence of unlawful market activity during the relevant period. The Order 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 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. Claimants filed notice of their claims on August 17, 2012, and they filed their direct testimony on September 21, 2012. Respondents' answering testimony is due November 28, 2012; staff's answering testimony is due January 15, 2013; and respondents' cross-answering testimony is due February 13, 2013. Claimants' rebuttal testimony is due March 8, 2013. The hearing is scheduled to begin on April 15, 2013. 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, and the California Attorney General (on behalf of CERS).

Both Avista Utilities and Avista Energy were buyers and sellers of energy in the Pacific Northwest energy market during the period between December 25, 2000 and June 20, 2001 and, are subject to potential claims in this proceeding, and if refunds are ordered by the FERC with regard to any particular contract, 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

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 allege that the holding ponds and remediation activities have adversely impacted their property. They allege contamination, decrease in water tables, reduced flow of streams on their property and other similar impacts to their property. They also seek punitive damages, attorney's 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 have subsequently appealed the court's decision and in September 2012 the Montana Supreme Court heard arguments on the appeal, and a decision is pending. 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. Although the final resolution of this complaint remains uncertain, based on information currently known to the Company's management, the Company does not expect this complaint will have a material effect on its financial condition, results of operations or cash flows.

Sierra Club and Montana Environmental Information Center Notice

On July 30, 2012, Avista Corp. received a Notice of Intent to Sue for violations of the Clean Air Act at Colstrip Steam Electric Station (Notice) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC), an Amended Notice was received on September 4, 2012, and a Second Amended Notice was received on October 1, 2012. The Notice, Amended Notice, and Second Amended Notice were all addressed to the Owner or Managing Agent of Colstrip, and to the other Colstrip co-owners: PPL Montana, Puget Sound Energy, Portland General Electric Company, NorthWestern Energy and PacifiCorp. The Notice alleges certain violations of the Clean Air Act, including the New Source Review, Title V and opacity requirements. The Amended Notice alleges additional opacity violations at Colstrip, and the Second Amended Notice alleges additional Title V allegations. All three notices state that Sierra Club and MEIC will request a United States District Court to impose injunctive relief and civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require reimbursement of Sierra Club's and MEIC's costs of litigation and attorney's fees. Under the Clean Air Act, lawsuits cannot be filed until 60 days after the applicable notice date. Avista Corp. is evaluating the allegations set forth in the Notice, Amended Notice and Second Amended Notice, and cannot at this time predict the outcome of this matter.

Harbor Oil Inc. Site

Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, the Environmental Protection Agency (EPA) Region 10 provided notification to Avista Corp. and several other parties, as customers of Harbor Oil, that the EPA had determined that hazardous substances were released at the Harbor Oil site in Portland, Oregon and that Avista Corp. and several other parties may be liable for investigation and cleanup of the site under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as the federal "Superfund" law, which provides for joint and several liability. The initial indication from the EPA is that the site may be contaminated with PCBs, petroleum hydrocarbons, chlorinated solvents and heavy metals. Six potentially responsible parties, including Avista Corp., signed an Administrative Order on Consent with the EPA on May 31, 2007 to conduct a remedial investigation and feasibility study (RI/FS). The draft final RI/FS was submitted to the EPA in December 2011 and was accepted as pre-final in March 2012. The EPA indicated in their approval letter that they intend to recommend a finding of No Further Action later in 2012. The actual cleanup, if any, will not occur until the RI/FS is finalized and approved by the EPA. Based on the review of its records related to Harbor Oil, the Company does not believe it is a major contributor to this potential environmental contamination based on the small volume of waste oil it delivered to the Harbor Oil site. As such, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows. The Company has expensed its share of the RI/FS ($0.5 million) for this 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 (DOE), 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, the DOE 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 the DOE in May 2012 and this was approved by the DOE in September 2012. This has now been submitted to the FERC for their approval. It is not possible to provide cost estimates at this time because the mitigation measures have not been fully approved by the FERC. However, management believes any potential costs would 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 EPA and the Idaho Department of Environmental Quality (Idaho DEQ) are preparing draft National Pollutant Discharge Elimination System permits and the 401 Water Quality Certifications for the Idaho dischargers, respectively, which once issued will be released for a 30-day public comment period.

The IPUC and the WUTC 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. In 2002, the Company submitted a Gas Supersaturation Control Program (GSCP) to the Idaho DEQ and U.S. Fish and Wildlife Service (USFWS). This submission was part of the Clark Fork Settlement Agreement for licensing the use of Cabinet Gorge. The GSCP provided for the possible opening and modification of two diversion tunnels around Cabinet Gorge to allow streamflow to be diverted when flows are in excess of powerhouse capacity. In 2007, engineering studies determined that the tunnels would not sufficiently reduce Total Dissolved Gas (TDG). In consultation with the Idaho DEQ and the USFWS, the Company developed an addendum to the GSCP. The GSCP addendum abandons the concept to reopen the two diversion tunnels and requires the Company to evaluate a variety of different options to abate TDG. In March 2010, the FERC approved the GSCP addendum of preliminary design for alternative abatement measures. In the second quarter of 2011, the Company completed preliminary feasibility assessments for several alternative abatement measures and determined that two alternatives will be considered for continued development. Further analysis and review of these alternatives is expected to be completed through 2012. 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 is evaluating 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. In 2009, the Company selected a contractor to design a permanent upstream passage facility at Cabinet Gorge. The Company anticipates that the design and cost estimates will be completed by the end of 2012 with construction taking place in 2013 and 2014.

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.

Aluminum Recycling Site

In October 2009, the Company (through its subsidiary Pentzer Venture Holdings II, Inc. (Pentzer)) received notice from the DOE proposing to find Pentzer liable for a release of hazardous substances under the Model Toxics Control Act, under Washington state law. Pentzer owns property that adjoins land owned by the Union Pacific Railroad (UPR). UPR leased their property to operators of a facility designated by the DOE as “Aluminum Recycling – Trentwood.” Operators of the UPR property maintained piles of aluminum “black dross,” which can be designated as a state-only dangerous waste in Washington State. In the course of its business, the operators placed a portion of the aluminum dross pile on the property owned by Pentzer. Pentzer does not believe it is a contributor to any environmental contamination associated with the dross pile, and submitted a response to the DOE’s proposed findings in November 2009. In December 2009, Pentzer received notice from the DOE that it had been designated as a potentially liable party for any hazardous substances located on this site. UPR completed a RI/FS Work Plan in June 2010. At that time, UPR requested a contribution from Pentzer towards the cost of performing the RI/FS and also an access agreement to investigate the material deposited on the Pentzer property. Pentzer concluded an access agreement with UPR in October 2010. UPR completed the RI/FS during 2011. Based on information currently known to the Company’s management, the Company does not expect this issue will have a material effect on its financial condition, results of operations or cash flows.

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. Avista Utilities’ business is managed based on the total regulated utility operation. Ecova is a provider of facility information and cost management services for multi-site customers 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.

AVISTA CORPORATION

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, 2012:						
Operating revenues	$ 292,535	$ 38,617	$ 9,930	$ 48,547	$ (450)	$ 340,632
Resource costs	153,801	—	—	—	—	153,801
Other operating expenses	64,449	33,868	9,229	43,097	(450)	107,096
Depreciation and amortization	28,255	3,260	131	3,391	—	31,646
Income from operations	27,940	1,489	570	2,059	—	29,999
Interest expense (2)	18,001	530	824	1,354	(91)	19,264
Income taxes	2,590	495	(1,477)	(982)	—	1,608
Net income attributable to Avista Corporation	7,660	640	(2,514)	(1,874)	—	5,786
Capital expenditures	57,964	1,023	619	1,642	—	59,606
For the three months ended September 30, 2011:						
Operating revenues	$ 302,001	$ 32,228	$ 9,931	$ 42,159	$ (450)	$ 343,710
Resource costs	171,393	—	—	—	—	171,393
Other operating expenses	60,579	23,790	8,386	32,176	(450)	92,305
Depreciation and amortization	26,341	1,784	180	1,964	—	28,305
Income from operations	26,859	6,654	1,365	8,019	—	34,878
Interest expense (2)	17,639	71	1,150	1,221	(5)	18,855
Income taxes	1,546	2,416	(245)	2,171	—	3,717
Net income attributable to Avista Corporation	7,582	3,467	(347)	3,120	—	10,702
Capital expenditures	69,716	897	233	1,130	—	70,846
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	191,407	104,392	27,285	131,677	(1,350)	321,734
Depreciation and amortization	83,327	9,455	511	9,966	—	93,293
Income from operations	153,049	1,860	2,111	3,971	—	157,020
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 attributable to Avista Corporation	65,157	962	(3,767)	(2,805)	—	62,352
Capital expenditures	178,440	3,248	660	3,908	—	182,348
For the nine months ended September 30, 2011:						
Operating revenues	$1,060,571	$ 91,207	$ 30,425	$121,632	$ (1,350)	$1,180,853
Resource costs	575,290	—	—	—	—	575,290
Other operating expenses	188,961	72,220	24,711	96,931	(1,350)	284,542
Depreciation and amortization	78,600	5,086	587	5,673	—	84,273
Income from operations	156,199	13,901	5,127	19,028	—	175,227
Interest expense (2)	52,134	206	3,912	4,118	(382)	55,870
Income taxes	35,857	5,005	75	5,080	—	40,937
Net income attributable to Avista Corporation	68,733	7,016	(128)	6,888	—	75,621
Capital expenditures	169,598	2,173	557	2,730	—	172,328
Total Assets:						
As of September 30, 2012	$3,732,530	$357,457	$100,269	$457,726	$ —	$4,190,256
As of December 31, 2011	$3,809,446	$292,940	$112,145	$405,085	$ —	$4,214,531

(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 October 22, 2012, the Company announced a voluntary severance incentive program. The Company has concluded that in order to achieve necessary long-term, Company-wide savings, it must undergo a reduction in its total workforce to reduce employment and related costs.

In general, all employees of Avista Corp. (not including any of its subsidiaries) who are not covered by a collective bargaining agreement are eligible to participate in the program. Employees who elect to participate in the program will be terminated only upon approval by the Company's management.

Each participant in the program will be entitled to receive severance pay determined based on the participant's years of service and base pay as of December 31, 2012. In no event will the severance pay under the program exceed 78 weeks of a participant's base pay. Severance pay will be distributed in a single lump sum cash payment to each participant as soon as administratively practicable after December 31, 2012 and in no event later than February 1, 2013.

All terminations under the voluntary severance incentive program are expected to be completed by December 31, 2012. The severance costs under this plan will be expensed in the fourth quarter of 2012 upon acceptance and cannot be reasonably estimated at this time.

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, 2012, and the related condensed consolidated statements of income and of comprehensive income, for the three-month and nine-month periods ended September 30, 2012 and 2011, and of equity and redeemable noncontrolling interests, and cash flows for the nine-month periods ended September 30, 2012 and 2011. 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, 2011, 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 28, 2012, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of accounting guidance for variable interest entities. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2011 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, 2012

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. (79.0 percent owned as of September 30, 2012) provides energy efficiency and cost management programs and services for multi-site customers and utilities throughout North America. Ecova's primary product 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, Spokane Energy, 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. 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, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Avista Utilities	$ 7,660	$ 7,582	$ 65,157	$ 68,733
Ecova	640	3,467	962	7,016
Other	(2,514)	(347)	(3,767)	(128)
Net income attributable to Avista Corporation	$ 5,786	$ 10,702	$ 62,352	$ 75,621

Executive Level Summary

Overall

Net income attributable to Avista Corporation was $5.8 million for the three months ended September 30, 2012, a decrease from $10.7 million for the three months ended September 30, 2011. This was primarily due to a decrease in earnings at our unregulated subsidiaries (Ecova and Other). Net income at other subsidiaries decreased due to 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. Net income at Ecova decreased due in part to an increase in other operating expenses and depreciation and amortization related to intangibles recorded in connection with the acquisitions of Prenova and LPB. Additionally, organic growth in Ecova's expense and data management services was slower than expected and there was delayed implementation (transitioning of customers onto Ecova's systems) of new customers in Ecova's energy management services, which did not offset the increased costs as expected.

These losses in net income were partially offset by a slight increase at Avista Utilities primarily due to warmer weather during the third quarter that increased retail electric cooling loads and the implementation of general rate increases, offset by an increase in other operating expenses, depreciation and amortization, and taxes other than income taxes.

Net income attributable to Avista Corporation was $62.4 million for the nine months ended September 30, 2012, a decrease from $75.6 million for the nine months ended September 30, 2011. This was due to a decrease in earnings at Avista Utilities (primarily due to reduced retail loads during the first half of the year and an increase in other operating expenses, depreciation and amortization, and taxes other than income taxes, partially offset by the implementation of general rate increases). Net income at Ecova decreased due in part to increased costs associated with completing and integrating the acquisitions of Prenova and LPB, as well as an increase in depreciation and amortization. Additionally, revenue growth for the expense and data management services and energy management services at Ecova was not as high as expected and did not offset the increased costs. Other businesses incurred a net loss largely due to an impairment loss of $2.4 million pre-tax ($1.5 million after-tax) recognized during the third quarter of 2012.

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 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.

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. General rate increases went into effect in Idaho on October 1, 2011, in Washington on January 1, 2012, and in Oregon effective March 15, 2011, June 1, 2011 and June 1, 2012. On April 2, 2012 we filed electric and natural gas general rate increase requests in Washington and on October 11, 2012 we filed electric and natural gas general rate increase requests in Idaho. On October 19, 2012, we entered into a settlement agreement in our Washington general rate cases that, if approved by the WUTC, would provide for electric and natural gas rate increases effective January 1, 2013 and January 1, 2014.

Our utility net income was $7.7 million for the three months ended September 30, 2012, an increase from $7.6 million for the three months ended September 30, 2011. The slight increase in utility earnings was primarily due to an increase in gross margin (operating revenues less resource costs) which was partially offset by increases in other operating expenses, depreciation and amortization, taxes other than income taxes, and interest expense. The increase in gross margin was primarily due to warmer weather that increased retail electric cooling loads, but was offset by reduced natural gas heating loads. Gross margin also benefited from general rate increases. Cooling degree days at Spokane were 37 percent above historical average for the third quarter of 2012 and were also 25 percent above the third quarter of 2011 which led to increased cooling loads. Other operating expenses increased for the third quarter of 2012 as compared to the third quarter of 2011 primarily due to increased pensions and other postretirement benefits, salaries, and general maintenance, partially offset by decreased outside service costs.

Our utility net income was $65.2 million for the nine months ended September 30, 2012, a decrease from $68.7 million for the nine months ended September 30, 2011. The decrease in utility earnings was primarily due to increases in other operating expenses, depreciation and amortization, taxes other than income taxes, and interest expense, partially offset by an increase in gross margin. The increase in gross margin was primarily due to warmer weather during the third quarter that increased retail electric cooling loads and general rate increases. This was partially offset by warmer weather during the heating season (primarily the first quarter) that reduced retail electric and natural gas loads. In addition, gross margin growth was limited in part by the continued weak economy and lower usage at certain industrial customers. Cooling degree days at Spokane were 24 percent above historical average for the first nine months of 2012 and were also 26 percent above the comparable period of 2011. Heating degree days at Spokane were close to historical average for the first nine months of 2012, but decreased 9 percent as compared to the first nine months of 2011. Other operating expenses increased for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011 primarily due to increased pensions and other postretirement benefits, salaries, and general maintenance, partially offset by decreased electric maintenance costs (which included the regulatory deferral of $5.4 million of maintenance costs) and outside service costs.

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 $178.4 million for the nine months ended September 30, 2012. We expect utility capital expenditures to be about $250 million for the full year of 2012. These estimates of capital expenditures are subject to continuing review and adjustment (see discussion under “Avista Utilities Capital Expenditures”).

On October 22, 2012, we announced a voluntary severance incentive program to achieve Company-wide long-term saving of employment and related costs. All terminations under the voluntary severance incentive program are expected to be completed by December 31, 2012. The severance costs under this plan will be expensed in the fourth quarter of 2012 and cash payments will be made after December 31, 2012, but no later than February 1, 2013. The impact of this program cannot be reasonably estimated at this time.

Ecova

Ecova had net income attributable to Avista Corporation of $0.6 million for the three months ended September 30, 2012, a decrease from $3.5 million for the three months ended September 30, 2011. This decrease was due in part to increased operating expenses associated with the acquisitions of Prenova and LPB, as well as an increase of $1.5 million in depreciation and amortization due to intangibles recorded in connection with the acquisitions. In addition, Ecova’s revenue growth in the expense and data management services was slower than expected and there was delayed implementation of new customers in Ecova’s energy management services, which did not offset the increased costs as expected.

Ecova had net income attributable to Avista Corporation of $1.0 million for the nine months ended September 30, 2012, a decrease from $7.0 million for the nine months ended September 30, 2011. Operating expenses increased due to the acquisitions of Prenova and LPB and depreciation and amortization increased $4.4 million due to intangibles recorded in connection with the acquisitions. In addition, Ecova's revenue growth in the expense and data management services was slower than expected and there was delayed implementation of new customers in Ecova's energy management services, which did not offset the increased costs as expected. This decrease was also due in part to $1.5 million in costs of completing the acquisitions and integrating Prenova and LPB during the first quarter of 2012.

On November 30, 2011, Ecova acquired Prenova, an Atlanta-based energy management company. The cash paid for the acquisition of Prenova of $35.6 million was funded primarily through borrowings under Ecova's committed credit agreement.

On January 31, 2012, Ecova acquired LPB, a Dallas-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.

While these acquisitions have grown the overall cost structure for Ecova for the three and nine months ended September 30, 2012, they have also increased both operating revenues and Ecova's market share and will allow Ecova to offer its clients a broader range of services leading to potential future earnings growth once the acquisitions are fully integrated into Ecova's operations.

The acquisition of Cadence Network in July 2008 was funded with the issuance of Ecova common stock. Under the transaction agreement, the previous owners of Cadence Network had a right to have their shares of Ecova common stock redeemed by Ecova during July 2011 or July 2012 if their investment in Ecova was not liquidated through either an initial public offering or sale of the business to a third party. These redemption rights were not exercised and expired effective July 31, 2012 and were reclassified to equity.

The value of the remaining redeemable noncontrolling interests associated with stock options and other outstanding redeemable stock at September 30, 2012 decreased from $12.9 million at December 31, 2011 to $6.7 million. Options are valued at their maximum redemption amount which is equal to their intrinsic value (fair value less exercise price). During 2012, the estimated fair value of Ecova common stock has decreased such that it is closer to the exercise price of the options which reduces the overall value of the redeemable noncontrolling interests.

Consistent with recent years, Ecova plans to continue to grow organically and potentially through strategic acquisitions. Ecova's acquisitions have been funded through internally generated cash, borrowings under Ecova's credit facility and the most recent acquisition of LPB was funded in part through an equity infusion from existing shareholders. If Ecova's capital needs exceed its credit facility capacity, it will require additional equity infusion 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. This 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.

Other Businesses

The net loss for these operations was $2.5 million for the three months ended September 30, 2012 compared to a net loss of $0.3 million for the three months ended September 30, 2011. The net loss for these operations was $3.8 million for the nine months ended September 30, 2012 compared to a net loss of $0.1 million for the nine months ended September 30, 2011. The decline in results was primarily due to an impairment loss of $2.4 million pre-tax ($1.5 million after-tax) incurred during the third quarter of 2012 related to the impairment of our investment in a fuel cell business and the write-off of our investment in a solar energy company. Also, there were increased litigation costs for the remaining contracts and previous operations of Avista Energy.

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.

We have a committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2017. As of September 30, 2012, there were $82.0 million of cash borrowings and $26.8 million in letters of credit outstanding. As of September 30, 2012, we had $291.2 million of available liquidity under this line of credit.

In July 2012, Ecova entered into a new five-year $125.0 million committed line of credit agreement with various financial institutions that replaced its $60.0 million committed line of credit agreement. As of September 30, 2012, Ecova had $58.0 million of borrowings outstanding under its committed line of credit agreement.

In June 2012, we entered into a bond purchase agreement with certain institutional investors in the private placement market for the purpose of issuing $80.0 million of 4.23 percent First Mortgage Bonds due in 2047. Issuance of the bonds will occur at closing in November 2012. Net total proceeds from the sale of the new bonds will be used to repay a portion of the borrowings outstanding under our $400.0 million committed line of credit and for general corporate purposes.

In May 2012, we cash settled interest rate swap contracts (notional amount of $75.0 million) and paid a total of $18.5 million. The interest rate swap contracts were settled in connection with the pricing of $80.0 million of First Mortgage Bonds as described above. Upon settlement of the 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 life of the forecasted interest payments.

In August 2012, we entered into two sales agency agreements under which we will sell shares of our common stock from time to time. In the third quarter of 2012, we sold 0.9 million shares for a total of $23.7 million (net of issuance costs). As of September 30, 2012, we had 1.8 million shares available to be issued under these agreements.

For the nine months ended September 30, 2012 we have issued $28.7 million (net of issuance costs) of common stock, including $23.7 million (net of issuance costs) under sales agency agreements. We do not expect to issue any further common stock under sales agency agreements during 2012. For 2013, we expect to issue up to $50 million of common stock in order to maintain our capital structure at an appropriate level for our business. After considering the issuances of long-term debt and common stock during 2012, we expect net cash flows from operating activities, together with cash available under our $400.0 million committed line of credit agreement, to provide adequate resources to fund:

- capital expenditures,
- dividends, and
- other contractual commitments.

Avista Utilities – Regulatory Matters

General Rate Cases

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

- 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 May 2011 (which was settled with new rates effective January 1, 2012) and in Idaho in July 2011 (which was settled with new rates effective October 1, 2011). We filed general rate cases in Washington in April 2012 and Idaho in October 2012.

Washington General Rate Cases

In December 2011, the Washington Utilities and Transportation Commission (WUTC) approved a settlement agreement in our electric and natural gas general rate cases filed in May 2011. As agreed to in the settlement agreement, base electric rates for our Washington customers increased by an average of 4.6 percent, which was designed to increase annual revenues by $20.0 million. Base natural gas rates for our Washington customers increased by an average of 2.4 percent, which was designed to increase annual revenues by $3.75 million. The new electric and natural gas rates became effective on January 1, 2012. No capital structure ratios or cost of capital components were specified in the settlement agreement.

The settlement agreement provided for the deferral of certain generation plant maintenance costs. In order to address the variability in year-to-year maintenance costs, beginning in 2011, we deferred certain changes in maintenance costs related to our Coyote Springs 2 natural gas-fired generation plant and our 15 percent ownership interest in Units 3&4 of the Colstrip generation plant. For 2011 and 2012 the Company will compare 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 defer the difference. This deferral was to occur annually, with no carrying charge, with deferred costs being amortized over a four-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 would be the actual 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 Washington were a regulatory asset of $3.3 million as of September 30, 2012 compared to a regulatory liability of $0.5 million as of December 31, 2011. As part of the settlement agreement in October 2012 to our latest general rate case discussed in further detail below, the parties have agreed that the maintenance cost deferral mechanism on these generation plants would terminate on December 31, 2012, with the four-year amortization of the 2011 and 2012 deferrals to conclude in 2015 and 2016, respectively.

On October 19, 2012 Avista Corp. and certain other parties in the Company's electric and natural gas rate case filings filed a settlement agreement with the WUTC that, if approved by the WUTC, would conclude the general rate requests filed on April 2, 2012. New rates would take effect on January 1, 2013 and January 1, 2014. The WUTC approved a settlement procedural schedule for hearings that provides the WUTC with the opportunity to address the settlement prior to the settlement's proposed implementation date of January 1, 2013. The parties' request to approve the settlement is not binding on the WUTC. Parties to the settlement agreement include the staff of the WUTC, Northwest Industrial Gas Users, Industrial Customers of Northwest Utilities and The Energy Project, a low-income customer advocacy group. The Public Counsel Section of the Washington Office of the Attorney General and the Northwest Energy Coalition did not join in the settlement agreement.

The settlement proposes that, effective January 1, 2013, we would increase base rates for our Washington electric customers by an overall 3.0 percent (designed to increase annual revenues by $13.6 million), and for our Washington natural gas customers by an overall 3.6 percent (designed to increase annual revenues by $5.3 million). The settling parties agree that a one-year credit of $4.4 million would be returned to electric customers from the existing Energy Recovery Mechanism (ERM) deferral balance so the net average electric rate increase impact to our customers in 2013 would be 2.0 percent. The credit to customers from the ERM balance would not impact our earnings.

The settlement also proposes that, effective January 1, 2014, we would 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 settling parties agree that a one-year credit of $9.0 million would 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 our customers effective January 1, 2014 would be 2.0 percent.

The settlement agreement also states that we would not file a general rate case in Washington that would cause an increase in base retail rates before January 1, 2015. We could, however, make a filing prior to January 2015, but new rates resulting from the filing would not take effect prior to January 1, 2015. This does not preclude us from filing annual rate adjustments such as the PGA.

Our original request filed with the WUTC in April 2012 included a base electric rate increase of 9.0 percent to produce $41.0 million in additional electric revenue. The original filing also requested a $10.1 million, or 7.0 percent, increase in natural gas revenues. The electric and natural gas filings reflected a proposed rate of return on rate base of 8.25 percent with a common equity ratio of 48.4 percent and a 10.9 percent return on equity. 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 return on rate base of 7.64 percent.

As part of the general rate case, we asked the WUTC to address the delay between the time when costs are incurred and the time when new rates are reviewed and approved by the WUTC and go into effect. This delay is referred to as regulatory lag. We contracted with a consultant to develop an attrition study to determine the annual revenue short-fall related to regulatory lag. We proposed an attrition adjustment in this general rate case filing, based on the attrition study, which was designed to eliminate the annual revenue short-fall related to regulatory lag. Although a specific attrition adjustment was not identified or agreed to in the settlement agreement, the results of the settlement agreement, if approved by the Commission, would represent incremental improvement in addressing regulatory lag, and would provide Avista the opportunity to improve its earned return in Washington in 2013 and 2014, as compared to prior years.

Idaho General Rate Cases

In September 2011, the IPUC approved a settlement agreement in our general rate case filed in July 2011. The new electric and natural gas rates became effective on October 1, 2011. As agreed to in the settlement agreement, base electric rates for our Idaho customers increased by an average of 1.1 percent, which is designed to increase annual revenues by $2.8 million. Base natural gas rates for our Idaho customers increased by an average of 1.6 percent, which is designed to increase annual revenues by $1.1 million.

As part of the settlement agreement, we agreed not to file a general rate case seeking a change in base electric or natural gas rates effective prior to April 1, 2013. This does not preclude us from filing annual rate adjustments such as the PCA and the PGA.

The settlement agreement also provides 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 will occur 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 a regulatory asset of $1.8 million as of September 30, 2012 compared to a regulatory asset of $0.1 million as of December 31, 2011.

On October 11, 2012, we filed electric and natural gas general rate cases with the IPUC. We have requested an overall increase in electric rates of 4.6 percent and an overall increase in natural gas rates of 7.2 percent. The filings are designed to increase annual electric revenues by $11.4 million and increase annual natural gas revenues by $4.6 million. Our requests are based on a proposed overall rate of return of 8.46 percent, with a common equity ratio of 50 percent and a 10.9 percent return on equity. The IPUC generally has up to 7 months to review the filings and issue a decision.

Oregon General Rate Cases

In March 2011, the OPUC approved an all-party settlement stipulation in our general rate case that was filed in September 2010. The settlement provides for an overall rate increase of 3.1 percent for our Oregon customers, designed to increase annual revenues by $3.0 million. Part of the rate increase became effective March 15, 2011, with the remaining increase effective June 1, 2011. An additional rate adjustment designed to increase revenues by $0.5 million became effective on June 1, 2012 to recover capital costs associated with certain reinforcement and replacement projects, having demonstrated that such projects were complete by November 1, 2011, and the costs incurred were prudent. In addition, rates increased by an additional $0.5 million, from June 1, 2012 through May 31, 2013, to recover the November 2011 through May 2012 deferred revenue requirement.

Proposed Electric Decoupling–Washington

In the September 2011 Washington general rate case settlement (which was approved by the WUTC in December 2011), one party, the Northwest Energy Coalition (NWEC), did not sign the agreement and continued to pursue an electric decoupling mechanism through a separate procedural schedule. On May 14, 2012, the WUTC consolidated this issue into our April 2012 Washington general rate case. Decoupling would sever the link between actual kWh sales and the recovery of our fixed costs. In summary, the NWEC proposes that actual fixed cost recovery per customer be compared to authorized fixed cost recovery per customer, and that any difference be deferred for later surcharge or rebate to customers.

The NWEC was not one of the parties that entered into the settlement agreement in the current Washington general rate case, and continues to advocate for an electric decoupling mechanism. As a part of the settlement agreement, we agreed to not support adoption of electric decoupling in this general rate case, nor would we seek to implement such a mechanism prior to our next general rate case. If the WUTC adopted a decoupling mechanism, this could affect future rates and our results of operations. However, there are many variables that could be incorporated into a decoupling mechanism, and we cannot currently predict the design of the mechanism, if any, the WUTC might ultimately adopt or the effect that any mechanism adopted may have on future rates or our results of operations.

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. Effective October 1, 2011, natural gas rates increased 1.0 percent in Idaho. Effective November 1, 2011, natural gas rates increased 1.0 percent in Washington, while decreasing 0.2 percent in Oregon. In Oregon, we absorb (gain or loss) 10 percent of the difference between actual and projected gas costs for supply that is not hedged. Total net deferred natural gas costs were a liability of $12.1 million as of December 31, 2011.

Effective March 1, 2012, natural gas rates decreased 6.4 percent in Washington and 6.0 percent in Idaho. Effective October 1, 2012, natural gas rates decreased 3.1 percent in Idaho. Effective November 1, 2012, natural gas rates decreased 4.4 percent in Washington and 7.5 percent in Oregon. Total net deferred natural gas costs were a liability of $13.2 million as of September 30, 2012.

As it relates to the Washington PGA, effective November 1, 2012, the WUTC approved Avista Corp.’s and the other natural gas utilities, PGAs on a temporary basis. The WUTC approved the recommendation of the staff of the WUTC 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. The timing for such analysis and potential workshops has not been determined.

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, is a decrease of 7.5 percent. The second step is an additional decrease of 0.8 percent, effective on January 1, 2013 for the net savings related to our purchase of the Klamath Falls Lateral transmission pipeline.

Power Cost Deferrals and Recovery Mechanisms

The Energy Recovery Mechanism (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 $19.7 million as of September 30, 2012 compared to $12.9 million as of December 31, 2011. As part of the proposed Washington general rate case settlement filed on October 19, 2012, during 2013 a one-year credit of $4.4 million would be returned to electric customers from the existing ERM deferral balance so the net average electric rate increase impact to customers in 2013 would be 2.0 percent. Additionally, during 2014 a one-year credit of $9.0 million would 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 be 2.0 percent. 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 of hydroelectric generation,
- the level of thermal generation (including changes in fuel prices), 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 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 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 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
+/- $0 - $4 million	0%	100%
+ between $4 million - $10 million	50%	50%
- between $4 million - $10 million	75%	25%
+/- excess 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 WUTC 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 29, 2012. 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 WUTC order. The 2011 ERM deferred power cost transactions were approved by an order from the WUTC in June 2012.

Under the terms of a prior settlement, we were required to make a filing (no sooner than June 2011), to allow all interested parties the opportunity to review the ERM, and make recommendations to the WUTC related to the continuation, modification or elimination of the ERM.

As part of the October 2012 Washington general rate case settlement, the proposed modifications to the ERM deadband and other sharing bands that were included in the original April 2, 2012 general rate case filing were not agreed to 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 current 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 regulatory liability of $4.3 million as of September 30, 2012 compared to $0.7 million as of December 31, 2011.

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. Regulations include validation of pipeline records for transmission pipelines, evaluation of transmission pipelines for automatic shut-off valves, consideration of increased "high consequence area" boundaries for transmission pipelines, increased installation of excess flow valves on gas service piping, as well as increased scrutiny on existing emergency preparedness plans, quality assurance plans and damage prevention programs, and broader federal oversight including broader use of fines and penalties to pipeline operators. We are evaluating the Act and cannot predict the impact the Act may ultimately have on our operations.

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, 2012 compared to the three months ended September 30, 2011

Utility revenues decreased $9.5 million, after elimination of intracompany revenues of $14.5 million in the third quarter of 2012 and $30.9 million in the third quarter of 2011. Including intracompany revenues, electric revenues decreased $8.4 million and natural gas revenues decreased $17.4 million. Retail electric revenues increased $6.3 million due to an increase in volumes sold primarily caused by warmer weather during the third quarter of 2012 compared to 2011 and also general rate increases. Sales of fuel decreased $18.0 million (reflecting decreased sales of natural gas fuel not used in generation). Wholesale electric revenues increased $4.4 million (primarily due to an increase in volumes sold). Retail natural gas revenues decreased $0.9 million due to a decrease in volumes caused by warmer weather, and wholesale natural gas revenues decreased $16.7 million (due to a decrease in wholesale prices and a decrease in wholesale volumes).

Non-utility revenues increased $6.4 million to $48.5 million primarily as a result of Ecova's acquisitions of Prenova effective November 30, 2011 and LPB effective January 31, 2012.

Utility resource costs decreased $17.6 million, after elimination of intracompany resource costs of $14.5 million in the third quarter of 2012 and $30.9 million in the third quarter of 2011. Including intracompany resource costs, electric resource costs decreased $16.0 million and natural gas resource costs decreased $18.0 million. The decrease in electric resource costs was primarily due to a decrease in other fuel costs (represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation as part of the resource optimization process) and the amortization of deferred power supply costs, partially offset by an increase in purchased power costs. The decrease in natural gas resource costs was primarily due to a decrease in natural gas purchased due to a decrease in prices and a decrease in volumes.

Utility other operating expenses increased $3.9 million primarily due to increased pensions and other postretirement benefits, salaries, and general maintenance, partially offset by decreased outside service costs.

Utility depreciation and amortization increased $1.9 million driven by additions to utility plant.

Utility taxes other than income taxes increased $1.3 million primarily reflecting higher retail revenue related taxes, as well as increased property taxes.

Non-utility other operating expenses increased $10.9 million primarily due to an increase of $10.1 million for Ecova reflecting increased costs necessary for business growth and the acquisitions of Prenova and LPB. The remaining increase was primarily due to litigation costs for the remaining contracts and previous operations of Avista Energy.

Non-utility depreciation and amortization increased $1.4 million primarily due to the amortization of intangibles recorded in connection with Ecova's acquisitions of Prenova and LPB.

Interest expense increased $0.4 million primarily due to the issuance of long-term debt in December 2011 that increased the balance of long-term debt outstanding.

Income taxes decreased $2.1 million and our effective tax rate was 21.2 percent for the three months ended September 30, 2012 compared to 24.2 percent for the three months ended September 30, 2011. This decrease in expense was primarily due to a decrease in income before income taxes. The decrease in the effective tax rate was due to adjustments associated with reconciling the 2011 federal income tax return to the amount included in the financial statements for 2011 which decreased income tax expense by $1.5 million for the three months ended September 30, 2012. In the third quarter of 2011, we increased our estimate of pension plan contributions for 2012 (which was tax deductible in the 2011 tax year). This change in our estimate reduced income tax expense through September 30, 2011 by $1.8 million representing the portion of the difference between pension costs recorded in the financial statements and the tax deductible cash contributions allocated to capital expenditures. Without this change in our estimate, our effective tax rate would have been 36.0 percent for the three months ended September 30, 2011.

Nine months ended September 30, 2012 compared to the nine months ended September 30, 2011

Utility revenues decreased $68.4 million, after elimination of intracompany revenues of $54.5 million for the nine months ended September 30, 2012 and $71.7 million for the nine months ended September 30, 2011. Including intracompany revenues, electric revenues decreased $30.7 million and natural gas revenues decreased $54.8 million. Retail electric revenues decreased $0.1 million due to a decrease in volumes sold which was primarily the result of warmer weather during the heating season, and due in part to a weakened economy and lower usage at certain industrial customers. This was mostly offset during the third quarter due to warmer weather (and increased cooling loads), which increased electric use per customer and also general rate increases. Sales of fuel decreased $47.9 million (reflecting lower usage of our thermal generating plants and increased sales of natural gas fuel not used in generation). These decreases in retail electric revenues and sales of fuel were partially offset by an increase in wholesale electric revenues of $16.8 million (due to an increase in volumes, partially offset by a decrease in wholesale prices). Retail natural gas revenues decreased $16.5 million due to a decrease in volumes caused by warmer weather, while wholesale natural gas revenues decreased $37.9 million (due to a decrease in wholesale prices, partially offset by an increase is wholesale volumes).

Non-utility revenues increased $24.0 million to $145.6 million primarily as a result of Ecova's acquisitions of Prenova effective November 30, 2011 and LPB effective January 31, 2012.

Utility resource costs decreased $74.5 million, after elimination of intracompany resource costs of $54.5 million for the nine months ended September 30, 2012 and $71.7 million for the nine months ended September 30, 2011. Including intracompany resource costs, electric resource costs decreased $37.9 million and natural gas resource costs decreased $53.7 million. The decrease in electric resource costs was primarily due to a decrease in other fuel costs (represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation as part of the resource optimization process) and the amortization of deferred power supply costs, partially offset by an increase in fuel costs (due to higher thermal generation) and power purchased. The decrease in natural gas resource costs was primarily due to a decrease in natural gas purchased due to a decrease in prices, partially offset by an increase in volumes and also an increase in the amortization of deferred natural gas costs.

Utility other operating expenses increased $2.4 million primarily due to increased pensions and other postretirement benefits, salaries, and general maintenance, partially offset by decreased electric maintenance costs (which included the regulatory deferral of $5.4 million of maintenance costs) and outside service costs.

Utility depreciation and amortization increased $4.7 million driven by additions to utility plant.

Utility taxes other than income taxes increased $2.1 million primarily reflecting higher property taxes.

Non-utility other operating expenses increased $34.7 million primarily due to an increase of $32.2 million for Ecova reflecting increased costs necessary for business growth and the acquisitions of Prenova and LPB, including transaction and integration costs of $1.5 million. The remaining increase was primarily due to litigation costs for the remaining contracts and previous operations of Avista Energy.

Non-utility depreciation and amortization increased $4.3 million primarily due to the amortization of intangibles recorded in connection with Ecova's acquisitions of Prenova and LPB.

Interest expense increased $2.0 million primarily due to the issuance of long-term debt in December 2011 that increased the balance of long-term debt outstanding.

Income taxes decreased $7.8 million and our effective tax rate was 34.6 percent for the nine months ended September 30, 2012 compared to 34.5 percent for the nine months ended September 30, 2011. This decrease in expense was primarily due to a decrease in income before income taxes.

Avista Utilities

Three months ended September 30, 2012 compared to the three months ended September 30, 2011

Net income for Avista Utilities was $7.7 million for the three months ended September 30, 2012, an increase from $7.6 million for the three months ended September 30, 2011. Avista Utilities' income from operations was $27.9 million for the three months ended September 30, 2012 compared to $26.9 million for the three months ended September 30, 2011. The increase in net income and income from operations was primarily due to an increase in gross margin (operating revenues less resource costs), offset by an increase in other operating expenses, depreciation and amortization, taxes other than income taxes, and interest expense.

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	
	2012	2011	2012	2011	2012	2011	2012	2011
Operating revenues	$240,187	$248,592	$66,850	$84,277	$(14,502)	$(30,868)	$292,535	$302,001
Less: resource costs	118,311	134,277	49,992	67,984	(14,502)	(30,868)	153,801	171,393
Gross margin	$121,876	$114,315	$16,858	$16,293	$ —	$ —	$138,734	$130,608

Avista Utilities' operating revenues decreased $9.5 million and resource costs decreased $17.6 million, which resulted in an increase of $8.1 million in gross margin. The gross margin on electric sales increased $7.6 million and the gross margin on natural gas sales increased $0.5 million. The increase in electric gross margin was primarily due to warmer weather that increased retail electric cooling loads. Gross margin on both electric and natural gas also benefited from general rate increases. For the three months ended September 30, 2012, we recognized a benefit of $0.8 million under the ERM in Washington compared to a benefit of $1.0 million for the three months ended September 30, 2011.

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 consolidated financial statements.

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	
	2012	2011	2012	2011
Residential	$ 70,534	$ 66,437	809	758
Commercial	76,180	73,264	841	825
Industrial	31,994	32,847	555	567
Public street and highway lighting	1,824	1,728	6	6
Total retail	180,532	174,276	2,211	2,156
Wholesale	25,826	21,455	872	752
Sales of fuel	28,385	46,366	—	—
Other	5,444	6,495	—	—
Total	$240,187	$248,592	3,083	2,908

Retail electric revenues increased $6.3 million primarily due to an increase in total MWhs sold (increased revenues $4.5 million) and an increase in revenue per MWh (increased revenues $1.8 million). The increase in MWhs sold was due to an increase in use per customer as a result of warmer weather during the third quarter. Compared to the third quarter of 2011, residential electric use per customer increased 6 percent and commercial use per customer increased 1 percent. Cooling degree days at Spokane were 37 percent above historical average for the third quarter of 2012 and were also 25 percent above the third quarter of 2011. The increase in revenue per MWh was primarily due to the Washington and Idaho general rate increases.

Wholesale electric revenues increased $4.4 million primarily due to an increase in sales volumes (increased revenues $3.5 million), and partially due to an increase in sales prices (increased revenues $0.9 million). The increase in sales volumes was primarily due to increased wholesale power optimization.

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 decreased $18.0 million due to a decrease in sales of natural gas fuel as part of thermal generation resource optimization. In the third quarter of 2012, $4.8 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. In the third quarter of 2011, $14.7 million of these sales were made to our natural gas operations.

The net margin on wholesale sales and sales of fuel is 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.

AVISTA CORPORATION

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	
	2012	2011	2012	2011
Residential	$16,998	$17,353	12,478	12,712
Commercial	10,134	10,506	10,891	10,931
Interruptible	441	458	859	823
Industrial	700	900	946	1,162
Total retail	28,273	29,217	25,174	25,628
Wholesale	35,349	52,001	136,825	149,833
Transportation	1,587	1,473	32,059	31,874
Other	1,641	1,586	14	14
Total	$66,850	$84,277	194,072	207,349

Retail natural gas revenues decreased $0.9 million due to a decrease in volumes (decreased revenues $0.5 million), and due to slightly lower retail rates (decreased revenues $0.4 million). We sold less retail natural gas in the third quarter of 2012 as compared to the third quarter of 2011 primarily due to warmer weather. Compared to the third quarter of 2011, residential natural gas use per customer decreased 3 percent and commercial use per customer decreased 1 percent.

Wholesale natural gas revenues decreased $16.7 million due to a decrease in prices (decreased revenues $13.3 million) and a decrease in volumes (decreased revenues $3.4 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. 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. We hedge against expected natural gas volumes with forward purchases. 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 2012, $9.7 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 2011, $16.1 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	
	2012	2011	2012	2011
Residential	318,413	316,106	285,710	283,381
Commercial	39,892	39,608	33,667	33,406
Interruptible	—	—	41	41
Industrial	1,402	1,387	263	259
Public street and highway lighting	542	456	—	—
Total retail customers	360,249	357,557	319,681	317,087

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

	2012	2011
Electric resource costs:		
Power purchased	$ 48,803	$ 39,783
Power cost amortizations, net	4,794	10,842
Fuel for generation	27,741	25,156
Other fuel costs	28,430	49,778
Other regulatory amortizations, net	3,754	4,001
Other electric resource costs	4,789	4,717
Total electric resource costs	118,311	134,277
Natural gas resource costs:		
Natural gas purchased	52,623	72,580
Natural gas cost amortizations, net	(3,198)	(5,369)
Other regulatory amortizations, net	567	773
Total natural gas resource costs	49,992	67,984
Intracompany resource costs	(14,502)	(30,868)
Total resource costs	$153,801	$171,393

Power purchased increased $9.0 million due to an increase in the volume of power purchases (increased costs $10.4 million), partially offset by a decrease in wholesale prices (decreased costs $1.4 million).

Net amortization of deferred power costs was $4.8 million for the third quarter of 2012 compared to $10.8 million for the third quarter of 2011. During the third quarter of 2012, we recovered (collected as revenue) $0.6 million of previously deferred power costs in Idaho through the PCA surcharge. The Washington ERM surcharge was eliminated in February 2010, since the previous balance of deferred power costs had been recovered. During the third quarter of 2012, actual power supply costs were below the amount included in base retail rates and we deferred $2.9 million in Washington and $1.3 million in Idaho for potential future rebate to customers.

Fuel for generation increased $2.6 million primarily due to an increase in thermal generation offset by a decrease in natural gas fuel prices.

Other fuel costs decreased $21.3 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. The associated revenues are reflected as sales of fuel.

The expense for natural gas purchased decreased $20.0 million due to a decrease in the price of natural gas (decreased costs $15.6 million) and a decrease in total therms purchased (decreased costs $4.4 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. 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, 2012 compared to the nine months ended September 30, 2011

Net income for Avista Utilities was $65.2 million for the nine months ended September 30, 2012, a decrease from $68.7 million for the nine months ended September 30, 2011. Avista Utilities' income from operations was $153.0 million for the nine months ended September 30, 2012 compared to $156.2 million for the nine months ended September 30, 2011. The decrease in net income and income from operations was primarily due to reduced retail loads during the first half of the year and an increase in other operating expenses, depreciation and amortization, and taxes other than income taxes, partially offset by the implementation of general rate increases. The decrease in net income from Avista Utilities was also due to an increase in interest expense.

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	
	2012	2011	2012	2011	2012	2011	2012	2011
Operating revenues	$716,090	$746,821	$330,631	$385,410	$(54,511)	$(71,660)	$992,210	$1,060,571
Less: resource costs	325,011	362,935	230,305	284,015	(54,511)	(71,660)	500,805	575,290
Gross margin	$391,079	$383,886	$100,326	$101,395	$ —	$ —	$491,405	$ 485,281

Avista Utilities' operating revenues decreased $68.4 million and resource costs decreased $74.5 million, which resulted in an increase of $6.1 million in gross margin. The gross margin on electric sales increased $7.2 million and the gross margin on natural gas sales decreased $1.1 million. The increase in electric gross margin was primarily due to warmer weather during the third quarter that increased retail electric cooling loads. This was partially offset by warmer weather during the heating season (primarily the first quarter) that reduced retail loads. In addition, electric gross margin growth was limited in part by the continued weak economy and lower usage at certain industrial customers. Natural gas gross margin decreased primarily due to warmer weather throughout the year that reduced retail heating loads. Gross margin on both electric and natural gas also benefited from general rate increases. For the nine months ended September 30, 2012, we recognized a benefit of $5.9 million under the ERM in Washington compared to $5.7 million for the nine months ended September 30, 2011.

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 consolidated financial statements.

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	
	2012	2011	2012	2011
Residential	$232,762	$236,818	2,650	2,699
Commercial	215,875	209,452	2,348	2,331
Industrial	90,226	92,896	1,569	1,615
Public street and highway lighting	5,431	5,200	19	19
Total retail	544,294	544,366	6,586	6,664
Wholesale	72,019	55,197	2,832	2,121
Sales of fuel	83,444	131,359	—	—
Other	16,333	15,899	—	—
Total	$716,090	$746,821	9,418	8,785

Retail electric revenues decreased $0.1 million due to a decrease in total MWhs sold (decreased revenues $6.4 million) offset by an increase in revenue per MWh (increased revenues $6.3 million). The decrease in MWhs sold was primarily the result of warmer weather during the heating season, and due in part to the weak economy and lower usage at certain industrial customers. This was mostly offset during the third quarter due to warmer weather (and increased cooling loads), which increased electric use per customer. Compared to the first nine months of 2011, residential electric use per customer decreased 2 percent. However, for the third quarter, residential electric use per customer increased 6 percent. Cooling degree days at Spokane were 24 percent above historical average for the first nine months of 2012 and were also 26 percent above the comparable period of 2011. Heating degree days at Spokane were close to historical average for the first nine months of 2012, but decreased 9 percent as compared to the first nine months of 2011. The increase in revenue per MWh was primarily due to the Washington and Idaho general rate increases.

Wholesale electric revenues increased $16.8 million due to an increase in sales volumes (increased revenues $18.1 million), partially offset by a decrease in sales prices (decreased revenues $1.3 million). The increase in sales volumes was primarily due to increased wholesale power optimization and lower than expected retail sales.

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 decreased $47.9 million due to a decrease in sales of natural gas fuel as part of thermal generation resource optimization activities and higher usage of our thermal generation plants in the first nine months of 2012 as compared to the first nine months of 2011. Higher usage of our thermal generation plants was due in part to decreased hydroelectric generation. For the nine months ended September 30, 2012, $23.6 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, 2011, $27.6 million of these sales were made to our natural gas operations.

The net margin on wholesale sales and sales of fuel is 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	
	2012	2011	2012	2011
Residential	$135,281	$145,138	124,844	134,502
Commercial	69,423	75,427	77,806	83,316
Interruptible	1,674	1,885	3,171	3,321
Industrial	2,790	3,243	3,781	4,212
Total retail	209,168	225,693	209,602	225,351
Wholesale	111,181	149,039	449,492	389,352
Transportation	5,155	4,914	112,320	111,996
Other	5,127	5,764	286	347
Total	$330,631	$385,410	771,700	727,046

Retail natural gas revenues decreased $16.5 million primarily due to a decrease in volumes (decreased revenues $15.7 million) and slightly lower retail rates (decreased revenues $0.8 million). We sold less retail natural gas in the first nine months of 2012 as compared to the first nine months of 2011 primarily due to warmer weather. Compared to the first nine months of 2011, residential and commercial natural gas use per customer decreased 8 percent and 7 percent, respectively.

Wholesale natural gas revenues decreased $37.9 million due to a decrease in prices (decreased revenues $52.7 million), partially offset by an increase in volumes (increased revenues $14.8 million). We plan for sufficient natural gas capacity to serve our retail customers on a theoretical peak day. As such, on nonpeak days we generally have more pipeline and storage capacity than what is needed. 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. We hedge against expected natural gas volumes with forward purchases. 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, 2012, $30.9 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, 2011, $44.0 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	
	2012	2011	2012	2011
Residential	318,368	316,402	286,268	284,238
Commercial	39,836	39,580	33,754	33,527
Interruptible	—	—	38	37
Industrial	1,397	1,375	261	254
Public street and highway lighting	497	454	—	—
Total retail customers	360,098	357,811	320,321	318,056

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

	2012	2011
Electric resource costs:		
Power purchased	$138,669	$123,580
Power cost amortizations, net	9,889	23,886
Fuel for generation	62,608	53,999
Other fuel costs	86,961	136,303
Other regulatory amortizations, net	12,925	11,686
Other electric resource costs	13,959	13,481
Total electric resource costs	325,011	362,935
Natural gas resource costs:		
Natural gas purchased	224,037	289,157
Natural gas cost amortizations, net	529	(14,264)
Other regulatory amortizations, net	5,739	9,122
Total natural gas resource costs	230,305	284,015
Intracompany resource costs	(54,511)	(71,660)
Total resource costs	$500,805	$575,290

Power purchased increased $15.1 million due to an increase in the volume of power purchases (increased costs $22.1 million), partially offset by a decrease in wholesale prices (decreased costs $7.0 million).

Net amortization of deferred power costs was $9.9 million for the nine months ended September 30, 2012 compared to $23.9 million for the nine months ended September 30, 2011. During the nine months ended September 30, 2012, we recovered (collected as revenue) $1.8 million of previously deferred power costs in Idaho through the PCA surcharge. The Washington ERM surcharge was eliminated in February 2010, since the previous balance of deferred power costs had been recovered. During the nine months ended September 30, 2012, actual power supply costs were below the amount included in base retail rates and we deferred $6.3 million in Washington and $1.7 million in Idaho for potential future rebate to customers.

Fuel for generation increased $8.6 million primarily due to an increase in thermal generation. This was due in part to a decrease in hydroelectric generation. The increase in thermal generation usage was partially offset by a decrease in natural gas fuel prices.

Other fuel costs decreased $49.3 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. The associated revenues are reflected as sales of fuel.

The expense for natural gas purchased decreased $65.1 million due to a decrease in the price of natural gas (decreased costs $80.2 million), partially offset by an increase in total therms purchased (increased costs $15.1 million). Total therms purchased increased due to an increase in wholesale sales which are used to balance loads and resources as part of the natural gas procurement and resource optimization process. 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, 2012 compared to the three months ended September 30, 2011

Ecova's net income attributable to Avista Corp. was $0.6 million for the three months ended September 30, 2012 compared to net income of $3.5 million for the three months ended September 30, 2011. Operating revenues increased $6.4 million and total operating expenses increased $11.6 million. The increase in operating revenues was primarily due to the acquisitions of Prenova effective November 30, 2011 and LPB effective January 31, 2012, which added $6.4 million to operating revenues for the third quarter of 2012. While operating revenues increased during the third quarter of 2012, they did not increase as much as anticipated due to slower organic growth in expense and data management services and delayed implementation of new customers for energy management services. This has contributed to a net decrease in net income attributable to Avista Corp. The increase in total operating expenses primarily reflects increased costs necessary to support ongoing and future business growth, as well as to support the increased revenue volume obtained through the acquisitions. Ecova experienced increases in employee costs, facilities costs, information technology costs and professional fees. Depreciation and amortization increased $1.5 million due to intangibles recorded in connection with the acquisitions. As of September 30, 2012, Ecova had 737 expense management customers representing 631,000 billed sites in North America. In the third quarter of 2012, Ecova managed bills totaling $5.5 billion, an increase of $0.8 billion as compared to the third quarter of 2011. This increase was due to an increase in the number of accounts managed, partially offset by a decrease in the average value of each bill (due in part to a decline in natural gas rates).

Nine months ended September 30, 2012 compared to the nine months ended September 30, 2011

Ecova's net income attributable to Avista Corp. was $1.0 million for the nine months ended September 30, 2012 compared to net income of $7.0 million for the nine months ended September 30, 2011. Operating revenues increased $24.5 million and total operating expenses increased $36.5 million. The increase in operating revenues was primarily due to the acquisitions of Prenova effective November 30, 2011 and LPB effective January 31, 2012, which added $18.0 million to operating revenues for the nine months ended September 30, 2012. While operating revenues increased during the nine months ended September 30, 2012, they did not increase as much as anticipated due to slower organic growth in expense and data management services and delayed implementation of new customers for energy management services. This has contributed to a net decrease in net income attributable to Avista Corp. The increase in total operating expenses primarily reflects increased costs necessary to support ongoing and future business growth, as well as to support the increased revenue volume obtained through the acquisitions. Ecova experienced increases in employee costs, facilities costs, information technology costs and professional fees. In addition, Ecova incurred $1.5 million in transaction and integration costs, and $0.3 million paid for the early termination of an earn-out contract. Depreciation and amortization increased $4.4 million due to intangibles recorded in connection with the acquisitions. In the first nine months of 2012, Ecova managed bills totaling $14.5 billion, an increase of $0.3 billion as compared to the first nine months of 2011. This increase was due to an increase in the number of accounts managed, partially offset by a decrease in the average value of each bill (due in part to a decline in natural gas rates).

Other Businesses

Three months ended September 30, 2012 compared to the three months ended September 30, 2011

The net loss from these operations was $2.5 million for the three months ended September 30, 2012 compared to a net loss of $0.3 million for the three months ended September 30, 2011. The decline in results was primarily due to losses on investments of $2.4 million for the third quarter of 2012 compared to $0.6 million for the third quarter of 2011. The losses for third quarter of 2012 were the result of 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. Additionally, there were increased litigation costs for the remaining contracts and previous operations of Avista Energy. These losses were partially offset by METALfx which had net income of $0.3 million for the third quarter of 2012 compared to $0.2 million for the third quarter of 2011.

Nine months ended September 30, 2012 compared to the nine months ended September 30, 2011

The net loss from these operations was $3.8 million for the nine months ended September 30, 2012 compared to a net loss of $0.1 million for the nine months ended September 30, 2011. The decline in results was primarily due to losses on investments of $3.0 million for the nine months ended September 30, 2012 compared to $0.6 million for nine months ended September 30, 2011. The losses for 2012 were the result of an impairment loss of $2.4 million pre-tax ($1.5 million after-tax) recognized during the third quarter of 2012 related to the impairment of our investment in a fuel cell business and the write-off of our investment in a solar energy company. Additionally, there were increased litigation costs for the remaining contracts and previous operations of Avista Energy. These losses were partially offset by METALfx which had net income of $1.1 million for each of the nine months ended September 30, 2012 and 2011.

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 2011 Form 10-K and have not changed materially from that discussion.

Liquidity and Capital Resources

Review of Condensed Consolidated Cash Flow Statement

Overall During the nine months ended September 30, 2012, positive cash flows from operating activities of $257.4 million, $21.0 million of borrowings under Avista Corp.'s $400.0 million committed line of credit, $23.0 million of borrowings under Ecova's committed line of credit, and the issuance of $28.7 million (net of issuance costs) of common stock were used to fund the majority of our cash requirements. These cash requirements included utility capital expenditures of $178.4 million, cash paid for the acquisition of LPB of $50.3 million and dividends of $51.2 million.

Operating Activities Net cash provided by operating activities was $257.4 million for the nine months ended September 30, 2012 compared to $240.4 million for the nine months ended September 30, 2011. Net cash provided by working capital components was $63.8 million for the nine months ended September 30, 2012, compared to $29.8 million for the nine months ended September 30, 2011. The net cash provided during the nine months ended September 30, 2012 primarily reflects net cash inflows related to accounts receivable (representing a seasonal decrease in receivables outstanding) and positive cash flows from other current assets.

The net cash provided during the nine months ended September 30, 2011 primarily reflects positive cash flows from accounts receivable (representing a seasonal decrease in receivables outstanding). These positive cash flows were partially offset by net cash outflows related to an increase in natural gas stored, other current assets (primarily representing an increase in income taxes receivable) and accounts payable (primarily related to a seasonal decrease in accounts payable for natural gas purchases and power purchased).

Contributions to our defined benefit pension plan were $44.0 million for the nine months ended September 30, 2012 compared to $26.0 million for the nine months ended September 30, 2011. Cash paid for interest was $43.5 million for the nine months ended September 30, 2012, compared to $41.6 million for the nine months ended September 30, 2011.

Investing Activities Net cash used in investing activities was $229.1 million for the nine months ended September 30, 2012, compared to $167.7 million for the nine months ended September 30, 2011. Utility property capital expenditures increased by $8.8 million for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. In the nine months ended September 30, 2012, a significant portion of Ecova's funds held for clients were held as securities available for sale (purchases of $88.8 million and sales and maturities of $103.5 million). The net cash paid by subsidiaries for acquisitions for the nine months ended September 30, 2012 of $50.3 million represents Ecova's acquisition of LPB.

Financing Activities Net cash used in financing activities was $20.1 million for the nine months ended September 30, 2012 compared to net cash used of $64.0 million for the nine months ended September 30, 2011. 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 $23.0 million (net of borrowings of $28.0 million and repayments of $5.0 million) and these proceeds were used to fund the acquisition of LPB. Cash dividends paid increased to $51.2 million (or 87 cents per share) for the nine months ended September 30, 2012 from $47.7 million (or 82.5 cents per share) for the nine months ended September 30, 2011. In May 2012, we cash settled interest rate swap agreements for $18.5 million related to the pricing of $80.0 million of long-term debt (the issuance will occur in November 2012). We issued $28.7 million of common stock during the nine months ended September 30, 2012. Client fund obligations at Ecova decreased $5.2 million.

During the nine months ended September 30, 2011, our short-term borrowings decreased $13.5 million. We issued $21.2 million of common stock during the nine months ended September 30, 2011, including $15.8 million under a sales agency agreement. Additionally, client fund obligations at Ecova increased by $4.0 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 does 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 $400.0 million committed line of credit.

As of September 30, 2012, we had $291.2 million of available liquidity under our committed line of credit. With our $400.0 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, 2012, we had cash deposited as collateral of $15.0 million and letters of credit of $19.3 million outstanding related to our energy derivative contracts. Price movements and/or a downgrade in our credit ratings could impact further 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, 2012, we would potentially be required to post additional collateral of up to $15.1 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 $45.4 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, 2012, we had interest rate swap agreements outstanding with a notional amount totaling $160 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, 2012, 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.

A variety of rules must be adopted by federal agencies (including the CFTC, SEC and the FERC) to implement the Dodd-Frank Act. These rules being developed and implemented will clarify the impact of the Dodd-Frank Act on Avista Corp., which may be significant.

Under the Dodd-Frank Act, "Swap Dealers" and "Major Swap Participants" generally will be required to collect minimum initial and variation margin from their counterparties for non-cleared swaps. However, the requirement varies with the type of counterparty and the regulator of the "Major Swap Participant" or "Swap Dealer." Avista Corp. should be categorized as a counterparty that is a non-financial end user for the purposes of the Dodd-Frank Act, i.e., as a non-financial entity that engages in derivatives to hedge commercial risk. In April 2012, the SEC and the CFTC issued a joint final rule with respect to security-based swap dealers or security-based major swap participants. Based on the proposed definitions and the de minimis rule, we believe that Avista Corp. is unlikely to be classified as a security-based swap dealer or security-based major swap participant.

The Dodd-Frank Act also requires certain swaps to be cleared and traded on exchanges or swap execution facilities. Such clearing requirements would result in a significant change from our current practice of bilaterally negotiated credit terms. An exemption from mandatory clearing is available under the Dodd-Frank Act for counterparties that are non-financial end users using swaps to hedge commercial risk.

In July 2012, the CFTC issued a final rule providing for an exemption from clearing requirements as outlined in Dodd-Frank for end users that enter into hedges to mitigate commercial risk. We expect most of our transactions to qualify under the end user exemption.

We will continue to monitor developments regarding implementation steps defined in the Act. We cannot predict the impact the Dodd-Frank Act may ultimately have on our operations.

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, 2012 and December 31, 2011 (dollars in thousands):

	September 30, 2012		December 31, 2011	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 392	— %	$ 7,474	0.3%
Current portion of nonrecourse long-term debt	14,631	0.6	13,668	0.5
Short-term borrowings	82,000	3.1	96,000	3.8
Long-term borrowings under committed line of credit	58,000	2.2	—	—
Long-term debt to affiliated trusts	51,547	2.0	51,547	2.0
Nonrecourse long-term debt	21,688	0.8	32,803	1.3
Long-term debt	1,148,047	43.5	1,169,826	45.7
Total debt	1,376,305	52.2	1,371,318	53.6
Total Avista Corporation stockholders' equity	1,259,744	47.8	1,185,701	46.4
Total	$2,636,049	100.0%	$2,557,019	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, reduces 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 $74.0 million during the nine months ended September 30, 2012 primarily due to net income, the issuance of common stock, and the expiration of the subsidiary noncontrolling interests redemption rights, 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 2012. Borrowings under our $400.0 million committed line of credit will supplement these funds to the extent necessary.

In June 2012, we entered into a bond purchase agreement with certain institutional investors in the private placement market for the purpose of issuing $80.0 million of 4.23 percent First Mortgage Bonds due in 2047. Issuance of the bonds will occur at closing in November 2012. The net proceeds from the sale of the new bonds will be used to repay a portion of the borrowings outstanding under our $400.0 million committed line of credit and for general corporate purposes. In connection with the pricing of the First Mortgage Bonds, we cash settled interest rate swap contracts and paid a total of $18.5 million, which will be amortized as a component of interest expense over the life of the debt.

In August 2012, we entered into two sales agency agreements under which we will sell shares of our common stock from time to time. In the third quarter of 2012, we sold 0.9 million shares for a total of $23.7 million (net of issuance costs). As of September 30, 2012, we had 1.8 million shares available to be issued under these agreements.

For the nine months ended September 30, 2012 we issued $28.7 million (net of issuance costs) of common stock. The additional shares were issued under sales agency agreements, as well as the dividend reinvestment and direct stock purchase plan and employee plans. The dividend reinvestment and direct stock purchase plan and employee plans will continue for the remainder of the year, however we do not expect to issue any further common stock under sales agency agreements during 2012. For 2013, we expect to issue up to $50 million of common stock in order to maintain our capital structure at an appropriate level for our business.

We have a committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2017.

Our committed line of credit agreement 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, 2012, we were in compliance with this covenant with a ratio of 52.2 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):

	2012	2011
Balance outstanding at end of period	$82,000	$ 96,500
Letters of credit outstanding at end of period	$26,815	$ 14,883
Maximum balance outstanding during the period	$92,500	$110,000
Average balance outstanding during the period	$25,000	$ 68,934
Average interest rate during the period	1.17%	1.38%
Average interest rate at end of period	1.08%	1.54%

The decrease in the average balance outstanding was due in part to a new intercompany borrowing arrangement between Avista Corp. and Ecova. As part of their cash management practices and operations, Ecova and Avista Corp. entered into an arrangement in January 2012 under which (1) Avista Corp. issued to Ecova a master unsecured promissory note and (2) Ecova will from time to time make short-term loans to Avista Corp. as a temporary investment of its funds received from its clients. The master promissory note 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 $32.9 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, 2012, 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.

Avista Utilities Capital Expenditures

We expect utility capital expenditures to be about $250 million for 2012 and about $260 million for 2013 and 2014. These estimates of capital expenditures are subject to continuing review and adjustment. Actual capital expenditures may vary from our estimates due to factors such as changes in business conditions, construction schedules and environmental requirements. Future generation resource decisions may be further impacted by legislation for restrictions on greenhouse gas (GHG) emissions and renewable energy requirements as discussed at "Environmental Issues and Other Contingencies."

Included in our estimates of capital expenditures is the replacement of our customer information and work management systems, which is expected to be completed by the end of 2014.

Ecova Credit Agreement

In July 2012, Ecova entered into a new $125.0 million committed line of credit agreement with various financial institutions that replaced its $60.0 million committed line of credit agreement and has an expiration date of July 2017. The credit agreement is secured by substantially all of Ecova's assets. There were $58.0 million of borrowings outstanding under Ecova's credit agreement as of September 30, 2012 classified as long-term. The proceeds from these borrowings were used to fund the acquisitions of Prenova in November 2011 and LPB in January 2012.

Ecova Redeemable Stock

In 2007, Ecova amended its employee stock incentive plan to provide 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 estimated fair value at the date of reacquisition. As the repurchase feature is at the discretion of the minority shareholders and option holders, there were redeemable noncontrolling interests of $6.7 million as of September 30, 2012 for the maximum redemption amount, which is equal to the intrinsic value (fair value less exercise price) of stock options outstanding, as well as outstanding redeemable stock. 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. Additionally, there were redeemable noncontrolling interests related to the 2008 Cadence Network acquisition, as the previous owners could have exercised a right to put their stock back to Ecova in July 2011 or July 2012 if their investment in Ecova was not liquidated through either an initial public offering or sale of the business to a third party. These redemption rights were not exercised and expired effective July 31, 2012 and were reclassified to equity.

Off-Balance Sheet Arrangements

As of September 30, 2012, we had $26.8 million in letters of credit outstanding under our $400.0 million committed line of credit, a decrease from $29.0 million as of December 31, 2011.

Pension Plan

As of September 30, 2012, our pension plan had assets with a fair value that was less than the benefit obligation under the plan. In the nine months ended September 30, 2012, we contributed $44 million to the pension plan (with no further contributions planned for the remainder of 2012). We expect to contribute a total of $132 million (or $44 million per year) to the pension plan in the period 2013 through 2015. The final determination of pension plan contributions for future periods is subject to multiple variables, most of which are beyond our control, including further changes to the fair value of pension plan assets and changes in actuarial assumptions (in particular the discount rate used in determining the benefit obligation).

The “Moving Ahead for Progress in the 21st Century” (MAP-21) was signed into federal law in July 2012. This law contains provisions that permit sponsors of single-employer defined benefit plans to use stabilized interest rate assumptions for certain funding calculations, thus decreasing required employer contributions and improving plan-funding attainment percentages. MAP-21 also increases Pension Benefit Guaranty Corporation (PBGC) premiums effective in 2013. We do not expect MAP-21 to have a significant impact on our pension contributions or PBGC premiums from 2012 through 2015.

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, 2012:

	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 level of “investment grade” credit rating is BBB-.
(2) Moody’s lowest level of “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 Corporation 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.

In May 2012, Avista Corp.’s Board of Directors declared a quarterly dividend of $0.29 per share on the Company’s common stock. In August 2012, Avista Corp.’s Board of Directors declared a quarterly dividend of $0.29 per share on the Company’s common stock.

Contractual Obligations

Our future contractual obligations have not changed materially from the amounts disclosed in the 2011 Form 10-K, with the following exceptions:

As of September 30, 2012, we had $82.0 million of borrowings outstanding under our committed line of credit. There were $61.0 million in borrowings outstanding as of December 31, 2011.

As of September 30, 2012, Ecova had $58.0 million of borrowings outstanding under its committed line of credit. There were $35.0 million in borrowings outstanding as of December 31, 2011.

Redeemable noncontrolling interests decreased to $6.7 million as of September 30, 2012 from $51.8 million as of December 31, 2011 primarily due to the expiration of noncontrolling interests redemption rights, and partially due to a decrease in the value.

In connection with the replacement of our customer information and work management systems, we have entered into various contracts with vendors in the total amount of $21.2 million through 2014.

Economic Conditions

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

We continue to experience customer growth as the regional economy recovers from the recession. We have three distinct metropolitan areas in our service area: Spokane, Washington, Coeur d'Alene, Idaho and Medford, Oregon; and we are tracking three separate economic indicators: employment change, unemployment rates and foreclosure rates. On a year-over-year basis, September 2012 employment growth rates are positive for our Spokane, Coeur d'Alene, and Medford service areas, and unemployment rates are lower in all three metropolitan areas. Foreclosure rates are below the U.S. rate in all three areas. Compared to the U.S. economy, the recovery in our service area has been slower. In 2012, we continue to expect overall economic growth in our service area to be somewhat lower than U.S. growth.

Seasonally adjusted nonfarm employment in our eastern Washington, northern Idaho, and southwestern Oregon metropolitan service areas exhibited moderate growth between September 2011 and September 2012. In Spokane, Washington employment growth was 1.8 percent with gains in manufacturing and business and professional services. Employment increased by 3.9 percent in Coeur d'Alene, Idaho, reflecting gains in manufacturing; professional and business services; trade, transport, and utilities; and education and health services. In Medford, Oregon, employment growth was 0.8 percent, with gains in manufacturing and financial activities. U.S. nonfarm sector jobs grew by 1.4 percent in the same twelve-month period.

The unemployment rate went down in September 2012 from the year earlier in Spokane, Medford, and Coeur d'Alene. In Spokane the rate was 8.7 percent in September 2011 and declined to 8.2 percent in September 2012; in Coeur d'Alene the rate went from 10.4 percent to 9.0 percent; and in Medford the rate declined from 10.4 percent to 9.0 percent. The U.S. rate declined from 9.0 percent to 7.8 percent in the same period.

The housing market in our service area continues to experience foreclosure rates lower than the national average. The September 2012 national rate was 0.14 percent, compared to 0.09 percent in Spokane County, Washington; 0.08 percent in Kootenai County (Coeur d'Alene), Idaho; and 0.05 percent in Jackson County (Medford), Oregon.

Environmental Issues and Other Contingencies

We are subject to environmental regulation by federal, state and local authorities. The generation, transmission, distribution, service and storage facilities in which we have ownership interests are designed and operated in compliance with applicable environmental laws. Furthermore, we conduct periodic reviews and audits of pertinent facilities and operations to ensure compliance and to respond to or anticipate emerging environmental issues. The Company's Board of Directors has a committee to oversee environmental issues.

We monitor legislative and regulatory developments at all levels of government for environmental issues, particularly those with the potential to impact the operation and productivity of our generating plants and other assets.

Environmental laws and regulations may:

- increase the operating costs of generating plants,
- increase the lead time and capital costs for the construction of new generating plants,
- require modification of our existing generating plants,

- require existing generating plant operations to be curtailed or shut down,
- reduce the amount of energy available from our generating plants,
- restrict the types of generating plants that can be built or contracted with, and
- require construction of specific types of generation plants at higher cost.

Compliance with environmental laws and regulations could result in increases to capital expenditures and operating expenses. We intend to seek recovery of any such costs through the ratemaking process.

Clean Air Act

We must comply with the requirements under the Clean Air Act (CAA) in operating our thermal generating plants. The CAA currently requires a Title V operating permit for Colstrip (which is in the process of being renewed), Coyote Springs 2 (which will expire in 2013), the Kettle Falls GS (which will be renewed in 2012), and the Rathdrum CT (which will expire in 2016). Boulder Park and the Northeast CT currently require only minor source operating permits based on their limited operation and emissions. The CAA also requires Acid Rain Program monitoring, reporting and emissions trading for Colstrip, Coyote Springs 2 and the Rathdrum CT. We continue to monitor legislative and regulatory developments for several programs within the CAA such as the National Ambient Air Quality Standards (NAAQS), New Source Performance Standards and the National Emission Standards for Hazardous Air Pollutants (NESHAPs) or Maximum Achievable Control Technology (MACT).

On July 30, 2012, Avista Corp. received a Notice of Intent to Sue for violations of the Clean Air Act at Colstrip Steam Electric Station (Notice) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC), an Amended Notice was received on September 4, 2012, and a Second Amended Notice was received on October 1, 2012. Avista Corp. is evaluating the allegations set forth in the Notice, Amended Notice and Second Amended Notice, and cannot at this time predict the outcome of this matter. See “Sierra Club and Montana Environmental Information Center Notice” in “Note 11 of the Notes to Condensed Consolidated Financial Statements” for further information on this matter.

Montana mercury regulation and the EPA’s Mercury Air Toxic Standards (MATS)

In 2006, the Montana Department of Environmental Quality (Montana DEQ) adopted final rules for the control of mercury emissions from coal-fired plants that impose strict emission limitations beginning in 2010. Colstrip installed and is successfully operating a mercury emission control system which meets the Montana mercury regulation.

The EPA finalized the MATS (formerly known as the Utility MACT) on December 16, 2011 to control hazardous air pollutants including mercury from coal and oil-fired power plants. The final version of the rule contains a mercury standard that is less stringent than the Montana mercury regulation; therefore, Colstrip’s existing emission control system should be sufficient to meet mercury compliance. For the remaining portion of the rule that specifically addresses Air Toxics (including metals and acid gases), the joint owners are currently evaluating what type of new emission control systems may be needed for MATS compliance in 2015. We are unable to determine to what extent or if there will be any material impacts to Colstrip at this time.

National Ambient Air Quality Standards (NAAQS)

We continue to monitor legislative and regulatory developments at both the state and national levels for potential operating limitations that may result from updates to the NAAQS. The CAA requires regular updates which have been recently court mandated to occur in June 2013 for nitrogen dioxide, ozone and particulate matter. We have thermal power plants in Washington, Idaho, Montana and Oregon. Since the EPA has designated most of the western states in which we operate as attainment areas, we do not anticipate any material impacts on our thermal plants from the required updates of these new standards at this time.

Regional Haze Program

The United States Congress addressed regional visibility in the 1990 CAA amendments and the EPA published the final Regional Haze regulations in 2005. The EPA’s regulations set a national goal of eliminating man-made visibility degradation in Class I areas by the year 2064. The states were expected to take actions through State Implementation Plans (SIPs) to make “reasonable progress” through 10-year plans, including application of Best Available Retrofit Technology (BART) requirements. In 2009, the EPA announced that many states had failed to submit the required SIPs by the 2007 deadline. In 2011, environmental groups sued the EPA for inaction which resulted in court ordered deadlines for a Montana Federal Implementation Plan (FIP) in July 2012.

BART is a retrofit program applied to large emission sources, including electric generating units built between 1962 and 1977. In February 2007, Colstrip was notified by the EPA that Colstrip Units 1 & 2 (of which we are not an owner) were determined to be subject to the EPA’s BART requirements. In November 2010, the EPA issued a request for additional reasonable progress information for Colstrip Units 3 & 4 (of which we are a 15 percent owner). On September 18, 2012, EPA finalized the Regional Haze FIP for Montana. The FIP includes both emission limitations and pollution controls for Colstrip Units 1 & 2. Colstrip Units 3 & 4 are not currently affected but will be evaluated for Reasonable Progress at the next review period in September 2017. We do not anticipate any material impacts on Units 3 & 4 at this time

Coal Ash Management/Disposal

Currently, coal combustion byproducts (CCBs) are not regulated by the EPA as a hazardous waste. Under a proposed rule issued in 2010, the EPA is reconsidering the classification of CCBs under the Resource Conservation and Recovery Act (RCRA). The draft rules included two options: to require management of CCBs as a hazardous waste under Subtitle C of the RCRA; or to regulate coal ash under Subtitle D, for non-hazardous solid wastes, with possible special waste requirements. Should the EPA determine to regulate CCBs as a hazardous waste under the RCRA, such action could have a significant impact on future operations of Colstrip.

Climate Change and Greenhouse Gas Emission Reduction Initiatives

Concerns about long-term global climate changes could have a significant effect on our business. Our operations could also be affected by changes in laws and regulations intended to mitigate the risk of or alter global climate changes, including restrictions on the operation of our power generation resources and obligations imposed on the sale of natural gas. Changing temperatures and precipitation, including snowpack conditions, affect the availability and timing of streamflows, which impact hydroelectric generation. Extreme weather events could increase service interruptions, outages and maintenance costs. Changing temperatures could also increase or decrease customer demand.

Greenhouse gas (GHG) emission standards could result in significant compliance costs. Such standards could also preclude us from developing, operating or contracting with certain types of generating plants.

We continue to monitor and evaluate the possible adoption of international, national, regional, or state GHG emission legislation and regulations. As the U.S. Congress has not enacted any comprehensive climate change legislation, for the foreseeable future climate change regulations are expected to emerge from the EPA and from individual states. In particular, climate change legislation was passed in the state of Washington, which includes a bill establishing GHG emissions reduction targets and another requiring that regulated sources report GHG emission from facilities that emit more than 10,000 metric tons of GHGs per year.

Although we are actively monitoring developments for climate change policies and restrictions on GHG emissions, it is important to note that we have relatively low GHG emissions as compared to other investor-owned utilities in the U.S. With 60 percent of our electric generation resource mix derived from renewable sources (including hydroelectric, biomass and contracts with wind generation projects) and a majority of our thermal generation fueled with natural gas, plus a commitment to energy efficiency, we are among the lowest carbon-emitting utilities in the nation.

Our Climate Policy Council (an interdisciplinary team of management and other employees) works to:

- facilitate internal and external communications regarding climate change issues,
- analyze policy impacts, anticipate opportunities and evaluate strategies for Avista Corp., and
- develop recommendations on climate related policy positions and action plans.

National Legislation

Climate change legislation has been proposed in the U.S. Congress; however, recent actions in the U.S. Congress indicate that climate change legislation is unlikely at this time. We continue to monitor the situation for new developments that could affect our business.

Recent EPA Initiatives Related to Climate Change

After a public comment and review period, in December 2009, the EPA issued an “endangerment finding” regarding GHG emissions from motor vehicles under section 202(a) of the Clean Air Act (CAA). Specifically, the EPA found that the combined emissions of GHG from new motor vehicles and new motor vehicle engines contribute to the GHG pollution which threatens public health and welfare. On April 1, 2010, the EPA and the Department of Transportation’s National Highway Safety Administration announced a joint final rule establishing GHG emission standards for mobile sources. The GHG emission standards for mobile sources became effective on January 2, 2011. The EPA has concluded that the CAA requires the agency to regulate GHG emissions from stationary sources through its preconstruction and operating permit programs on the date when EPA regulations require any source (mobile or stationary) to meet GHG emission limits. In May 2010, the EPA finalized a rule establishing an applicability threshold for regulating GHG emissions from stationary sources through the preconstruction and operating permit programs.

The EPA issued a series of rules on December 23, 2010 to narrow the CAA permitting requirement so that facilities with GHG emissions below the levels set in the tailoring rule do not need permits, as well as to give the EPA authority to issue GHG permits in states that need to revise their permitting regulations to cover GHG emissions. On January 2, 2011, rules took effect requiring that permits issued under the CAA for new large stationary sources begin to address GHG emissions, as well as require Best Available Control Technology (BACT) to control these emissions. On July 20, 2011, the EPA finalized a rule that defers, for a period of three years, the GHG permitting requirements for carbon dioxide for utilities, boilers and other industrial facilities using biomass. The EPA’s final decision to regulate GHG emissions from stationary sources and to establish applicability thresholds for GHGs has been challenged in the U.S. Court of Appeals for the District of Columbia.

The EPA is planning to issue regulations controlling GHG emissions from electric generating units. According to a previously announced schedule, the EPA was to propose standards for natural gas, oil and coal-fired electric generating units by September 30, 2011, and issue final standards by May 26, 2012. The EPA recently announced that it would not meet this schedule and has not yet provided a new schedule. The EPA had agreed to the original schedule as part of a settlement, as modified, with several states, local governments and environmental organizations that sued the EPA over its failure to update emissions standards for power plants and refineries as required by Section 111 of the CAA. Section 111 requires the EPA to issue New Source Performance Standards that set emissions limits for new facilities and, under certain circumstances, address emissions from existing facilities. These rules could significantly impact the costs of modifying existing thermal plants as well as building new thermal generation sources. We cannot determine or estimate the costs of compliance with such measures at this time.

In September 2009, the EPA finalized the Mandatory Reporting Rule (MRR) that requires facilities emitting over 25,000 metric tons of GHG a year to report their emissions to the EPA beginning in January 2011 for 2010 emissions. On March 18, 2011, the EPA issued a rule extending the deadline for reporting 2010 GHG emissions data to September 30, 2011. Based on rule applicability criteria, Colstrip, Coyote Springs 2, and the Rathdrum CT recently reported GHGs to the EPA. The rule also required that natural gas distribution system throughput be reported along with the development of a GHG Monitoring Plan. On March 22, 2010, the EPA proposed to further amend its reporting rule to include several new source categories, including reporting of GHG fugitive emissions from electric power transmission and distribution systems, fugitive emissions from natural gas distribution systems, and fugitive emissions from natural gas storage facilities. Reporting for these additional sources for 2011 emissions was required by September 30, 2012.

On March 27, 2012, the EPA proposed a Carbon Pollution Standard for new power plants. The EPA proposed that new fossil-fuel-fired power plants meet an output-based standard of 1,000 pounds of carbon dioxide per megawatt-hour. New power plants that are designed to use coal or petroleum coke would be able to incorporate technology to reduce carbon dioxide emissions to meet the standard, such as carbon capture and storage. For purposes of this rule, fossil-fuel-fired generation units include fossil-fuel-fired boilers, integrated gasification combined cycle units and stationary combined cycle turbine units that generate electricity for sale and are larger than 25 MW; simple cycle turbine units are exempt. The proposal would not apply to existing units including modifications such as changes needed to meet other air pollution standards and new power plant units that have permits and start construction within 12 months of this proposal. We are unable to determine if or to what extent the proposed standard, if adopted, would have on our thermal generating facilities at this time.

State Activities

The states of Washington and Oregon have statutory targets to reduce GHG emissions. Washington’s targets are intended to reduce GHG emissions to 1990 levels by 2020; to 25 percent below 1990 levels by 2035; and to 50 percent below 1990 levels by 2050. Oregon’s targets would reduce GHG emissions to 10 percent below 1990 levels by 2020 and 75 percent below 1990 levels by 2050. Both states enacted their targets expecting that they would be met through a combination of renewable energy standards, and assorted “complementary policies,” such as land-use policies, energy efficiency codes for buildings, renewable fuel standards and vehicle emission standards. However, neither state has yet adopted any comprehensive requirements aimed specifically at achieving these targets.

Washington State’s Department of Ecology has adopted regulations to ensure that its State Implementation Plan comports with the requirements of the EPA’s regulation of GHG emissions. We will continue to monitor actions by the Department as it may proceed to adopt additional regulations under its CAA authorities. Late in 2011, a Federal District Court ruled that the Department of Ecology must require six refineries located in the state to install reasonably available control technology (RACT) to control and reduce their greenhouse gas emissions. This decision turned, on the meaning of “air contaminate” under Washington law, the United States Supreme Court decision in Massachusetts v. EPA (549 U.S. 497 (2007)), and administrative actions were taken by the EPA. The Court’s decision could have implications for other industrial emitters of greenhouse gases in the state of Washington, in part because the decision will require the Department of Ecology to determine what measures might constitute RACT. If and how the decision might impact other industries will not be clear until the decision is finalized and any challenges to it have been exhausted.

Washington and Oregon apply a GHG emissions performance standard to electric generation facilities used to serve retail loads in their jurisdictions. The emissions performance standard prevents utilities from constructing or purchasing generation facilities, or entering into power purchase agreements of five years or longer duration to purchase energy produced by plants that have emission levels higher than 1,100 pounds of GHG per MWh. The Department of Commerce has commenced a process that is expected to result in the adoption of a lower emissions performance standard this year (2012); a new standard will be applicable until at least 2017.

Initiative Measure 937 (I-937), the Energy Independence Act, was passed into law through the 2006 General Election in Washington. I-937 requires investor-owned, cooperative, and government-owned electric utilities with over 25,000 customers to acquire qualified renewable energy resources and/or renewable energy credits in incremental amounts until those resources or credits equal 15 percent of the utility's total retail load in 2020. I-937 also requires these utilities to meet biennial energy conservation targets, the first of which must be met in 2012. Furthermore, by January 1, 2012, electric utilities subject to I-937's mandates were required to acquire enough qualified incremental renewable energy and/or renewable energy credits to meet 3 percent of their load. This renewable energy standard increases to 9 percent in 2016. Failure to comply with renewable energy and energy efficiency standards could result in penalties of $50 per MWh or greater being assessed against a utility for each MWh it is deficient in meeting a standard. A utility would be deemed to comply with the renewable energy standard if it invests at least 4 percent of its total annual retail revenue requirement on the incremental costs of renewable energy resources and/or renewable energy credits. As noted in the following section, we have taken the steps necessary to meet the requirements of I-937. In 2012, the Governor signed into law Senate Bill 5575, which amended I-937 to define our Kettle Falls Generating Station and certain other biomass energy facilities which commenced operation before March 31, 1999, as resources that may be used to meet the renewable energy standards beginning in 2016.

Wind Power Purchase Agreement

In June 2011, we entered into a 30-year power purchase agreement (PPA) with Palouse Wind, LLC (Palouse Wind), an affiliate of First Wind Holdings, LLC. Under the PPA, we will acquire all of the power and renewable attributes produced by a wind project being developed by Palouse Wind in Whitman County, Washington. The wind project, which is currently under construction, is expected to have a nameplate capacity of approximately 105 MW and produce approximately 40 aMW with deliveries beginning by the end of 2012. We decided to enter into this PPA due, in part, to market changes reducing the cost of renewable resource projects. This was due, in part, to tax incentives for the construction of renewable resource projects that remain in effect through 2012. We acquired the development rights for a separate wind generation site near Reardan, Washington in 2008 and continue to study that site in preparation for later development. We plan to meet the state of Washington's renewable energy standards until 2016 with a combination of qualified upgrades at our existing hydroelectric generation plants. The power purchased from Palouse Wind will help to meet our Washington renewable energy requirements beginning in 2016, as well as provide a new energy resource to serve our system retail load requirements. Under the PPA, we have the option to purchase the wind project each year following the 10^{th} anniversary of the commercial operation date at a price determined under the contract.

Fisheries

A number of species of fish in the Northwest, including the Snake River sockeye salmon and fall chinook salmon, the Kootenai River white sturgeon, the upper Columbia River steelhead, the upper Columbia River spring chinook salmon and the bull trout, are listed as threatened or endangered under the Federal Endangered Species Act. Efforts to protect these and other species have not directly impacted generation levels at any of our hydroelectric facilities. We purchase power under long-term contracts with certain PUDs with hydroelectric generation projects on the Columbia River that are directly impacted by ongoing mitigation measures for salmon and steelhead. The reduction in generation at these projects is relatively minor, resulting in minimal economic impact on our operations at this time. We cannot predict the economic costs to us resulting from future mitigation measures. We received a 45-year FERC operating license for Cabinet Gorge and Noxon Rapids in March 2001 that incorporates a comprehensive settlement agreement. The restoration of native salmonid fish, including bull trout, is a key part of the agreement. The result is a collaborative native salmonid restoration program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana on the lower Clark Fork River, consistent with requirements of the FERC license. The U.S. Fish & Wildlife Service issued an updated Critical Habitat Designation for bull trout in 2010 that includes the lower Clark Fork River, as well as portions of the Coeur d'Alene basin within our Spokane River Project area, and is currently developing a final Bull Trout Recovery Plan under the ESA. Issues related to these activities are expected to be worked out through the ongoing collaborative effort of our Clark Fork and Spokane River FERC licenses. See "Hydroelectric Licensing" and "Fish Passage at Cabinet Gorge and Noxon Rapids" in "Note 11 of the Notes to Condensed Consolidated Financial Statements" for further information.

Western Power Market Issues

The FERC continues to conduct proceedings and investigations related to market controls within the western United States that include proposals by certain parties to impose refunds, and some of the FERC's decisions have been appealed in Federal Courts. Certain parties have asserted claims for significant refunds from us, which could result in liabilities for refunding revenues recognized in prior periods. We have joined other parties in opposing these proposals. We believe that we have adequate reserves established for refunds that may be ordered. The refund proceedings provide that any refunds would be offset against unpaid energy debts due to the same party. As of September 30, 2012, our accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from defaulting parties. See "California Refund Proceeding" and "Pacific Northwest Refund Proceeding" in "Note 11 of the Notes to Condensed Consolidated Financial Statements" for further information on the refund proceedings.

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, 2012. Please refer to the 2011 Form 10-K. The following table presents energy commodity derivative fair values as a net asset or (liability) as of September 30, 2012 that are expected to settle in each respective year (dollars in thousands):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical	Financial	Physical	Financial	Physical	Financial	Physical	Financial
2012	$(2,381)	$ (6,069)	$(10,857)	$ (3,237)	$ (38)	$ 589	$ (674)	$ 1,357
2013	(3,246)	(15,572)	(15,579)	(10,375)	(47)	13,578	(1,236)	5,863
2014	(2,699)	145	(5,352)	(2,532)	(20)	2,788	(1,222)	(1,015)
2015	(2,570)	(122)	(1,354)	448	(192)	(67)	—	(570)
2016	(2,637)	—	(137)	117	(200)	—	—	—
Thereafter	(5,220)	—	—	—	(1,025)	—	—	—

Credit Risk

Our credit risk has not materially changed during the nine months ended September 30, 2012. See the 2011 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 and control procedures to manage these risks, both qualitative and quantitative. The 2011 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, 2012. See the 2011 Form 10-K.

As of September 30, 2012, we had interest rate swap agreements with a total notional amount of $160.0 million with mandatory cash settlement dates of June 2013, October 2014, and October 2015 (which we entered into in September 2011 and June 2012).

As of September 30, 2012, we had a current derivative liability of $3.8 million and a long-term derivative asset of $5.1 million, with an offsetting regulatory asset and liability on the Condensed Consolidated Balance Sheets in accordance with regulatory accounting practices. In May 2012, we cash settled interest rate swap contracts (notional amount of $75.0 million) and paid a total of $18.5 million. The interest rate swap contracts were settled in connection with the pricing of $80.0 million of First Mortgage Bonds. Upon settlement of the interest rate swaps, the regulatory asset or liability (included as part of long-term debt) will be amortized as a component of interest expense over the life of the forecasted interest payments.

Foreign Currency Risk

Our qualitative foreign currency risk disclosures have not materially changed during the nine months ended September 30, 2012. See the 2011 Form 10-K. As of September 30, 2012, we had a current derivative liability for foreign currency hedges of less than $0.1 million included in other current liabilities on the Condensed Consolidated Balance Sheet. As of September 30, 2012, we had entered into 30 Canadian currency forward contracts with a notional amount of $6.6 million ($6.5 million Canadian).

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

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 has 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, 2012.

There have been no changes in the Company's internal control over financial reporting that occurred during the third quarter of 2012 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 the 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 2011 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 2011 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, 2012, formatted in XBRL (Extensible Business Reporting Language) and furnished 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, 2012	/s/ Mark T. Thies
	Mark T. Thies Senior Vice President and Chief Financial Officer (Principal Financial Officer)

EXHIBIT 12

AVISTA CORPORATION

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

	Nine months ended September 30, 2012	Years Ended December 31 2011	2010	2009	2008	2007
Fixed charges, as defined:						
Interest charges	$ 54,990	$ 69,591	$ 72,010	$ 61,361	$ 74,914	$ 80,095
Amortization of debt expense and premium - net	2,876	4,617	4,414	5,673	4,673	6,345
Interest portion of rentals	1,709	2,154	2,027	1,874	1,601	1,612
Total fixed charges	$ 59,575	$ 76,362	$ 78,451	$ 68,908	$ 81,188	$ 88,052
Earnings, as defined:						
Pre-tax income from continuing operations	$ 95,813	$160,171	$146,105	$134,971	$120,382	$ 63,061
Add (deduct):						
Capitalized interest	(1,765)	(2,942)	(298)	(545)	(4,612)	(3,864)
Total fixed charges above	59,575	76,362	78,451	68,908	81,188	88,052
Total earnings	$ 153,623	$233,591	$224,258	$203,334	$196,958	$147,249
Ratio of earnings to fixed charges	2.58	3.06	2.86	2.95	2.43	1.67

EXHIBIT 15

November 7, 2012

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, 2012 and 2011, as indicated in our report dated November 7, 2012; 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, 2012, 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. 333-163609 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
November 7, 2012

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, 2012

/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, 2012

/s/ Mark T. Thies

Mark T. Thies
Senior Vice President and
Chief Financial Officer
(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, 2012 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, 2012

/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 and
Chief Financial Officer