UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE QUARTERLY PERIOD ENDED March 31, 2013 OR

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

Commission file number 1-3701

AVISTA CORPORATION

(Exact name of Registrant as specified in its charter)

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

Registrant's telephone number, including area code: 509-489-0500
Web site: http://www.avistacorp.com

None

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

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

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

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

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

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

As of April 30, 2013, 59,920,196 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

AVISTA CORPORATION
INDEX

FORWARD-LOOKING STATEMENTS

From time to time, we make forward-looking statements such as statements regarding projected or future:

- financial performance;
- cash flows;
- capital expenditures;
- dividends;
- capital structure;
- other financial items;
- strategic goals and objectives;
- business environment; and
- plans for operations.

These statements have underlying assumptions (many of which are based, in turn, upon further assumptions). Such statements are made both in our reports filed under the Securities Exchange Act of 1934, as amended (including this Quarterly Report on Form 10-Q), and elsewhere. Forward-looking statements are all statements except those of historical fact including, without limitation, those that are identified by the use of words that include "will," "may," "could," "should," "intends," "plans," "seeks," "anticipates," "estimates," "expects," "forecasts," "projects," "predicts," and similar expressions. Forward-looking statements (including those made in this Quarterly Report on Form 10-Q) are subject to a variety of risks and uncertainties and other factors. Many of these factors are beyond our control and they could have a significant effect on our operations, results of operations, financial condition or cash flows. This could cause actual results to differ materially from those anticipated in our statements. Such risks, uncertainties and other factors include, among others:

- weather conditions (temperatures, precipitation levels and wind patterns) which affect energy demand and electric generation, including the effect of precipitation and temperature on hydroelectric resources, the effect of wind patterns

on wind-generated power, weather-sensitive customer demand, and similar impacts on supply and demand in the wholesale energy markets;

- state and federal regulatory decisions that affect our ability to recover costs and earn a reasonable return including, but not limited to, disallowance or delay in the recovery of capital investments and operating costs;
- changes in wholesale energy prices that can affect operating income, cash requirements to purchase electricity and natural gas, value received for wholesale sales, collateral required of us by counterparties on wholesale energy transactions and credit risk to us from such transactions, and the market value of derivative assets and liabilities;
- economic conditions in our service areas, including customer demand for utility services;
- the effect of increased customer energy efficiency;
- our ability to obtain financing through the issuance of debt and/or equity securities, which can be affected by various factors including our credit ratings, interest rates and other capital market conditions and the global economy;
- the potential effects of legislation or administrative rulemaking, including possible effects on our generating resources of restrictions on greenhouse gas emissions to mitigate concerns over global climate changes;
- changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension and other postretirement medical plans, which can affect future funding obligations, pension and other postretirement medical expense and pension and other postretirement medical plan liabilities;
- volatility and illiquidity in wholesale energy markets, including the availability of willing buyers and sellers, and prices of purchased energy and demand for energy sales;
- the outcome of pending regulatory and legal proceedings arising out of the “western energy crisis” of 2000 and 2001, including possible refunds;
- the outcome of legal proceedings and other contingencies;
- changes in, and compliance with, environmental and endangered species laws, regulations, decisions and policies, including present and potential environmental remediation costs;
- wholesale and retail competition including alternative energy sources, suppliers and delivery arrangements and the extent that new uses for our services may materialize;
- the ability to comply with the terms of the licenses for our hydroelectric generating facilities at cost-effective levels;
- severe weather or natural disasters that can disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies and support services;
- explosions, fires, accidents, mechanical breakdowns, or other incidents that may cause unplanned outages at any of our generation facilities, transmission and distribution systems or other operations;
- public injuries or damages arising from or allegedly arising from our operations;
- blackouts or disruptions of interconnected transmission systems (the regional power grid);
- disruption to information systems, automated controls and other technologies that we rely on for our operations, communications and customer service;
- terrorist attacks, cyber attacks or other malicious acts that may disrupt or cause damage to our utility assets or to the national economy in general, including any effects of terrorism, cyber attacks or vandalism that damage or disrupt information technology systems;
- delays or changes in construction costs, and/or our ability to obtain required permits and materials for present or prospective facilities;
- changes in the costs to implement new information technology systems and/or obstacles that impede our ability to complete such projects timely and effectively;
- changes in the long-term 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 changes in demand by significant customers;
- the loss of key suppliers for materials or services;

- default or nonperformance on the part of any parties from which we purchase and/or sell capacity or energy;
- deterioration in the creditworthiness of our customers;
- potential decline in our credit ratings, with effects including impeded access to capital markets, higher interest costs, and certain ratings trigger covenants in our financing arrangements and wholesale energy contracts;
- increasing health care costs and the resulting effect on health insurance provided to our employees and retirees;
- increasing costs of insurance, more restricted coverage terms and our ability to obtain insurance;
- work force issues, including changes in collective bargaining unit agreements, strikes, work stoppages or the loss of key executives, availability of workers in a variety of skill areas, and our ability to recruit and retain employees;
- the potential effects of negative publicity regarding business practices - whether true or not - which could result in litigation or a decline in our common stock price;
- changes in technologies, possibly making some of the current technology obsolete;
- changes in tax rates and/or policies;
- changes in the payment acceptance policies of Ecova’s client vendors that could reduce operating revenues;
- potential difficulties for Ecova in integrating acquired operations and in realizing expected opportunities, diversions of management resources and losses of key employees, challenges with respect to operating new businesses and other unanticipated risks and liabilities; and
- changes in our strategic business plans, which may be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses.

Our expectations, beliefs and projections are expressed in good faith. We believe they are reasonable based on, without limitation, an examination of historical operating trends, our records and other information available from third parties. However, there can be no assurance that our expectations, beliefs or projections will be achieved or accomplished. Furthermore, any forward-looking statement speaks only as of the date on which such statement is made. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time to time, and it is not possible for us to predict all such factors, nor can we assess the effect of each such factor on our business or the extent that any such factor or combination of factors may cause actual results to differ materially from those contained in any forward-looking statement.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

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

	2013	2012
Operating Revenues:		
Utility revenues	$ 431,127	$ 405,460
Ecova revenues	42,407	37,010
Other non-utility revenues	9,372	9,787
Total operating revenues	482,906	452,257
Operating Expenses:		
Utility operating expenses:		
Resource costs	229,630	211,012
Other operating expenses	65,444	65,322
Depreciation and amortization	27,935	27,318
Taxes other than income taxes	25,817	25,166
Ecova operating expenses:		
Other operating expenses	35,990	35,774
Depreciation and amortization	3,493	2,836
Other non-utility operating expenses:		
Other operating expenses	9,345	8,267
Depreciation and amortization	190	168
Total operating expenses	397,844	375,863
Income from operations	85,062	76,394
Interest expense	19,692	19,137
Interest expense to affiliated trusts	118	140
Capitalized interest	(940)	(525)
Other income-net	(2,145)	(1,709)
Income before income taxes	68,337	59,351
Income tax expense	25,236	21,138
Net income	43,101	38,213
Net loss (income) attributable to noncontrolling interests	(760)	175
Net income attributable to Avista Corporation shareholders	$ 42,341	$ 38,388
Weighted-average common shares outstanding (thousands), basic	59,866	58,581
Weighted-average common shares outstanding (thousands), diluted	59,898	58,950
Earnings per common share attributable to Avista Corporation shareholders:		
Basic	$ 0.71	$ 0.66
Diluted	$ 0.71	$ 0.65
Dividends paid per common share	$ 0.305	$ 0.29

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

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

	2013	2012
Net income	$ 43,101	$ 38,213
Other Comprehensive Income (Loss):		
Unrealized investment gains/(losses) - net of taxes of $(39) and $39, respectively	(70)	69
Reclassification adjustment for realized gains on investment securities included in net income - net of taxes of $(1) and $(5), respectively	(1)	(11)
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $99 and $82, respectively	184	153
Total other comprehensive income	113	211
Comprehensive income	43,214	38,424
Comprehensive loss (income) attributable to noncontrolling interests	(760)	175
Comprehensive income attributable to Avista Corporation shareholders	$ 42,454	$ 38,599

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands
(Unaudited)

	March 31, 2013	December 31, 2012
Assets:		
Current Assets:		
Cash and cash equivalents	$ 89,197	$ 75,464
Accounts and notes receivable-less allowances of $44,652 and $44,155, respectively	190,197	193,683
Utility energy commodity derivative assets	4,706	4,139
Regulatory asset for utility derivatives	14,577	35,082
Investments and funds held for clients	103,392	88,272
Materials and supplies, fuel stock and natural gas stored	30,318	47,455
Deferred income taxes	31,968	34,281
Income taxes receivable	3,556	2,777
Other current assets	39,103	24,641
Total current assets	507,014	505,794
Net Utility Property:		
Utility plant in service	4,115,253	4,054,644
Construction work in progress	134,741	143,098
Total	4,249,994	4,197,742
Less: Accumulated depreciation and amortization	1,196,506	1,174,026
Total net utility property	3,053,488	3,023,716
Other Non-current Assets:		
Investment in exchange power-net	15,721	16,333
Investment in affiliated trusts	11,547	11,547
Goodwill	76,762	75,959
Intangible assets-net of accumulated amortization of $28,322 and $26,030, respectively	43,884	46,256
Long-term energy contract receivable of Spokane Energy	49,269	52,033
Other property and investments-net	52,181	46,542
Total other non-current assets	249,364	248,670
Deferred Charges:		
Regulatory assets for deferred income tax	72,946	79,406
Regulatory assets for pensions and other postretirement benefits	301,725	306,408
Other regulatory assets	106,291	103,946
Non-current utility energy commodity derivative assets	925	1,093
Non-current regulatory asset for utility derivatives	22,192	25,218
Other deferred charges	18,193	18,928
Total deferred charges	522,272	534,999
Total assets	$ 4,332,138	$ 4,313,179

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

Dollars in thousands
(Unaudited)

	March 31, 2013	December 31, 2012
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 161,503	$ 198,914
Client fund obligations	103,238	87,839
Current portion of long-term debt	50,354	50,372
Current portion of nonrecourse long-term debt of Spokane Energy	15,309	14,965
Short-term borrowings	52,500	52,000
Utility energy commodity derivative liabilities	12,345	29,515
Other current liabilities	184,534	142,544
Total current liabilities	579,783	576,149
Long-term debt	1,178,766	1,178,367
Nonrecourse long-term debt of Spokane Energy	13,872	17,838
Long-term debt to affiliated trusts	51,547	51,547
Long-term borrowings under committed line of credit	54,000	54,000
Regulatory liability for utility plant retirement costs	237,967	234,128
Pensions and other postretirement benefits	274,180	283,985
Deferred income taxes	522,920	524,877
Other non-current liabilities and deferred credits	106,395	110,215
Total liabilities	3,019,430	3,031,106
Commitments and Contingencies (See Notes to Condensed Consolidated Financial Statements)		
Redeemable Noncontrolling Interests	7,970	4,938
Equity:		
Avista Corporation Stockholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 59,912,087 and 59,812,796 shares outstanding, respectively	891,759	889,237
Accumulated other comprehensive loss	(6,587)	(6,700)
Retained earnings	398,804	376,940
Total Avista Corporation stockholders' equity	1,283,976	1,259,477
Noncontrolling Interests	20,762	17,658
Total equity	1,304,738	1,277,135
Total liabilities and equity	$ 4,332,138	$ 4,313,179

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

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

	2013	2012
Operating Activities:		
Net income	$ 43,101	$ 38,213
Non-cash items included in net income:		
Depreciation and amortization	31,618	30,322
Provision (benefit) for deferred income taxes	1,120	(303)
Power and natural gas cost amortizations, net	2,545	4,098
Amortization of debt expense	947	965
Amortization of investment in exchange power	613	613
Stock-based compensation expense	1,464	1,618
Equity-related AFUDC	(1,391)	(843)
Pension and other postretirement benefit expense	10,949	9,727
Amortization of Spokane Energy contract	2,764	2,541
Other	1,118	(151)
Contributions to defined benefit pension plan	(14,670)	(14,700)
Changes in working capital components:		
Accounts and notes receivable	2,432	16,079
Materials and supplies, fuel stock and natural gas stored	17,137	15,652
Other current assets	(14,288)	21,265
Accounts payable	(20,778)	(16,112)
Other current liabilities	40,698	12,315
Net cash provided by operating activities	105,379	121,299
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(70,645)	(57,771)
Other capital expenditures	(819)	(1,144)
Federal grant payments received	1,567	2,855
Cash paid by subsidiaries for acquisitions, net of cash received	—	(50,310)
Decrease (increase) in funds held for clients	2,816	(35,857)
Purchase of securities available for sale	(24,956)	(36,461)
Sale and maturity of securities available for sale	7,000	27,000
Other	(1,649)	(2,628)
Net cash used in investing activities	(86,686)	(154,316)

The Accompanying Notes are an Integral Part of These Statements.

Table of Contents

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

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

	2013	2012
Financing Activities:		
Net increase (decrease) in short-term borrowings	$ 500	$ (24,000)
Borrowings from Ecova line of credit	3,000	25,000
Repayment of borrowings from Ecova line of credit	(3,000)	—
Redemption and maturity of long-term debt	(101)	(65)
Maturity of nonrecourse long-term debt of Spokane Energy	(3,622)	(3,307)
Long-term debt and short-term borrowing issuance costs	(11)	(33)
Issuance of common stock	1,149	1,437
Cash dividends paid	(18,384)	(17,073)
Purchase of subsidiary noncontrolling interest	—	(134)
Increase in client fund obligations	15,399	45,169
Issuance of subsidiary noncontrolling interest	—	3,714
Other	110	350
Net cash provided by (used in) financing activities	(4,960)	31,058
Net increase (decrease) in cash and cash equivalents	13,733	(1,959)
Cash and cash equivalents at beginning of period	75,464	74,662
Cash and cash equivalents at end of period	$ 89,197	$ 72,703
Supplemental Cash Flow Information:		
Cash paid during the period:		
Interest	$ 7,391	$ 6,680
Income taxes	1,329	1,322
Non-cash financing and investing activities:		
Accounts payable for capital expenditures	4,730	2,677
Redeemable noncontrolling interests	2,870	1,764

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS

Avista Corporation

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

	2013	2012
Common Stock, Shares:		
Shares outstanding at beginning of period	59,812,796	58,422,781
Issuance of common stock	99,291	248,020
Shares outstanding at end of period	59,912,087	58,670,801
Common Stock, Amount:		
Balance at beginning of period	$ 889,237	$ 855,188
Equity compensation expense	1,461	1,120
Issuance of common stock, net of issuance costs	1,149	1,437
Equity transactions of consolidated subsidiaries	(88)	2
Balance at end of period	891,759	857,747
Accumulated Other Comprehensive Loss:		
Balance at beginning of period	(6,700)	(5,637)
Other comprehensive income	113	211
Balance at end of period	(6,587)	(5,426)
Retained Earnings:		
Balance at beginning of period	376,940	336,150
Net income attributable to Avista Corporation shareholders	42,341	38,388
Cash dividends paid (common stock)	(18,384)	(17,073)
Valuation adjustments and other noncontrolling interests activity	(2,093)	(1,647)
Balance at end of period	398,804	355,818
Total Avista Corporation stockholders' equity	1,283,976	1,208,139
Noncontrolling Interests:		
Balance at beginning of period	17,658	174
Net income attributable to noncontrolling interests	733	31
Deconsolidation of variable interest entity	—	(673)
Other	2,371	—
Balance at end of period	20,762	(468)
Total equity	$ 1,304,738	$ 1,207,671
Redeemable Noncontrolling Interests:		
Balance at beginning of period	$ 4,938	$ 51,809
Net income (loss) attributable to noncontrolling interests	27	(206)
Issuance of subsidiary noncontrolling interests	—	3,714
Purchase of subsidiary noncontrolling interests	—	(134)
Valuation adjustments and other noncontrolling interests activity	3,005	2,450
Balance at end of period	$ 7,970	$ 57,633

The Accompanying Notes are an Integral Part of These Statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

The accompanying condensed consolidated financial statements of Avista Corporation (Avista Corp. or the Company) for the interim periods ended March 31, 2013 and 2012 are unaudited; however, in the opinion of management, the statements reflect all adjustments necessary for a fair statement of the results for the interim periods. The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) for interim financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. The Condensed Consolidated Statements of Income for the interim periods are not necessarily indicative of the results to be expected for the full year. These condensed consolidated financial statements do not contain the detail or footnote disclosure concerning accounting policies and other matters which would be included in full fiscal year consolidated financial statements; therefore, they should be read in conjunction with the Company's audited consolidated financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2012 (2012 Form 10-K). Please refer to the section “Acronyms and Terms” in the 2012 Form 10-K for definitions of terms. The acronyms and terms are an integral part of these condensed consolidated financial statements.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corporation is an energy company engaged in the generation, transmission and distribution of energy, as well as other energy-related businesses. Avista Utilities is an operating division of Avista Corp., comprising the regulated utility operations. Avista Utilities generates, transmits and distributes electricity in parts of eastern Washington, northern Idaho, and western Montana. 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 northeastern and southwestern Oregon. Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility businesses, except Spokane Energy, LLC (Spokane Energy). Avista Capital’s subsidiaries include Ecova, Inc. (Ecova), a 78.9 percent owned subsidiary as of March 31, 2013. Ecova is a provider of energy efficiency and other facility information and cost management programs and services for multi-site customers and utilities throughout North America. See Note 12 for business segment information.

Basis of Reporting

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

Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on net income. These taxes are generally based on revenues or the value of property. Utility related taxes collected from customers (primarily state excise taxes and city utility taxes) are recorded as operating revenue and expense and totaled the following amounts for the three months ended March 31 (dollars in thousands):

	2013	2012
Utility taxes	$ 17,906	$ 17,834

Other Income - Net

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

	2013	2012
Interest income	$ (258)	$ (275)
Interest income on regulatory deferrals	(13)	(8)
Equity-related AFUDC	(1,391)	(843)
Net loss on investments	398	439
Other income	(881)	(1,022)
Total (1)	$ (2,145)	$ (1,709)

(1) The 2012 amount includes an immaterial correction of an error related to the reclassification of certain operating expenses

from other expense-net to utility and non-utility other operating expenses and utility taxes other than income taxes. This correction did not have an impact on net income or earnings per share. See further discussion of this reclassification below under "Immaterial Correction of an Error."

Materials and Supplies, Fuel Stock and Natural Gas Stored

Inventories of materials and supplies, fuel stock and natural gas stored are recorded at average cost for our regulated operations and the lower of cost or market for our non-regulated operations and consisted of the following as of March 31, 2013 and December 31, 2012 (dollars in thousands):

	March 31, 2013	December 31, 2012
Materials and supplies	$ 26,511	$ 26,058
Fuel stock	3,478	4,121
Natural gas stored	329	17,276
Total	$ 30,318	$ 47,455

Investments and Funds Held for Clients and Client Fund Obligations

In connection with the bill paying services, Ecova collects funds from its clients and remits the funds to the appropriate utility or other service provider. Some of the funds collected are invested by Ecova and classified as investments and funds held for clients, and a related liability for client fund obligations is recorded. Investments and funds held for clients include cash and cash equivalent investments, money market funds and investment securities classified as available for sale. Ecova does not invest the funds directly for the clients' benefit; therefore, Ecova bears the risk of loss associated with the investments. Investments and funds held for clients as of March 31, 2013 are as follows (dollars in thousands):

	Amortized Cost (1)	Unrealized Gain (Loss)	Fair Value
Cash and cash equivalents	$ 26,315	$ —	$ 26,315
Securities available for sale:			
U.S. government agency	64,458	47	64,505
Municipal	3,595	33	3,628
Corporate fixed income – financial	4,001	10	4,011
Corporate fixed income – industrial	3,869	48	3,917
Certificates of deposit	1,000	16	1,016
Total securities available for sale	76,923	154	77,077
Total investments and funds held for clients	$ 103,238	$ 154	$ 103,392

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

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

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

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

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

Proceeds from sales, maturities and calls of securities available for sale were $7.0 million and $27.0 million, for the three months ended March 31, 2013 and March 31, 2012, respectively. Gross realized gains were negligible for the three months ended March 31, 2013 and March 31, 2012. There were not any gross realized losses during these periods.

Contractual maturities of securities available for sale as of March 31, 2013 and December 31, 2012 are as follows (dollars in thousands):

	Due within 1 year	After 1 but within 5 years	After 5 but within 10 years	After 10 years	Total
March 31, 2013	$ 5,428	$ 16,162	$ 51,486	$ 4,001	$ 77,077
December 31, 2012	3,047	11,786	41,485	3,003	59,321

Actual maturities may differ due to call or prepayment rights and the effective maturity was 3.8 years as of March 31, 2013 and 1.9 years as of December 31, 2012.

Goodwill

Goodwill arising from acquisitions represents the excess of the purchase price over the estimated fair value of net assets acquired. The Company evaluates goodwill for impairment using a discounted cash flow model on at least an annual basis or more frequently if impairment indicators arise. The Company completed its annual evaluation of goodwill for potential impairment as of December 31, 2012 for Ecova and as of November 30, 2012 for the other businesses and determined that goodwill was not impaired at that time.

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

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

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

Intangible Assets

Intangible assets represent the amounts assigned to client relationships related to the Ecova acquisition of Cadence Network in 2008 (estimated amortization period of 12 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 6 years), and software development costs (estimated amortization period of 3 to 5 years).

Amortization expense related to Intangible Assets was as follows for the three months ended March 31 (dollars in thousands):

	2013	2012
Intangible asset amortization	$ 2,579	$ 2,097

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

	2013	2014	2015	2016	2017
Estimated amortization expense	$ 8,074	$ 9,663	$ 7,599	$ 6,477	$ 5,584

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

	March 31, 2013	December 31, 2012
Client backlog and relationships	$ 33,559	$ 32,059
Software development costs	35,296	33,990
Other	3,351	6,237
Total intangible assets	72,206	72,286
Client relationships accumulated amortization	(8,808)	(7,793)
Software development costs accumulated amortization	(17,645)	(16,557)
Other accumulated amortization	(1,869)	(1,680)
Total accumulated amortization	(28,322)	(26,030)
Total intangible assets - net	$ 43,884	$ 46,256

Of the total net intangible assets above, intangible assets associated with Ecova represent approximately $43.1 million and $45.4 million at March 31, 2013 and December 31, 2012, respectively.

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Condensed Consolidated Balance Sheets measured at estimated fair value. In certain defined conditions, a derivative may be specifically designated as a hedge for a particular exposure. The accounting for any particular derivative depends on the intended use of that derivative and the resulting designation.

The Washington Utilities and Transportation Commission (UTC) and the Idaho Public Utilities Commission (IPUC) issued accounting orders authorizing Avista Utilities to offset commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of 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.

Accumulated Other Comprehensive Loss

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

	March 31, 2013	December 31, 2012
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $(3,599) and $(3,698), respectively	$ (6,684)	$ (6,867)
Unrealized gain on securities available for sale - net of taxes of $54 and $99, respectively	97	167
Total accumulated other comprehensive loss	$ (6,587)	$ (6,700)

The following table details the reclassifications out of accumulated other comprehensive loss by component for the three months ended March 31, 2013 (dollars in thousands):

Details about Accumulated Other Comprehensive Loss Components	Amounts Reclassified from Accumulated Other Comprehensive Loss	Affected Line Item in Statement of Income
Realized gains on investment securities	$ 2	Other income-net
	2	Total before tax
	(1)	Tax expense
	$ 1	Net of tax
Amortization of defined benefit pension items		
Amortization of net loss	$ (4,891)	(a)
Adjustment due to effects of regulation	4,608	(a)
	(283)	Total before tax
	99	Tax benefit
	$ (184)	Net of tax

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

Contingencies

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

Voluntary Severance Incentive Program

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

Immaterial Correction of an Error

Subsequent to the issuance of the Company's condensed consolidated financial statements for the three months ended March 31, 2012, the Company's management identified certain employee-related operating expenses, dues and donations, and other operating expenses totaling $2.3 million for the three months ended March 31, 2012, which had been erroneously included in “Other expense-net” in the previously issued financial statements rather than as a reduction to “Income from operations.” Accordingly, such classification has been corrected in the accompanying Condensed Consolidated Statements of Income for the three months ended March 31, 2012 by including these costs within “other” operating expenses. The restated items are also reflected in the information presented in Note 12, Information by Business Segments. Such items had no effect on net income or earnings per share.

Reclassifications

Certain prior year amounts on the Company's Condensed Consolidated Statements of Income and Condensed Consolidated Statements of Cash Flows have been reclassified to conform to the current year presentation. In the current year Condensed Consolidated Statements of Income, Ecova operating revenues and operating expenses have been reclassified to separate line items. Previously, such amounts had been classified within the line items captioned "Other non-utility revenues" and “Other non-utility operating expenses”, respectively. Also, see Note 1, “Other Income-Net” concerning a corrective reclassification made to certain 2012 operating expenses. In the current year Condensed Consolidated Statements of Cash Flows, "Amortization of investment in exchange power", "Stock-based compensation expense", "Pension and other postretirement benefit expense" and "Amortization of Spokane Energy contract" have been added as their own line items. These were previously included in "Other" in the operating activities section.

NOTE 2. NEW ACCOUNTING STANDARDS

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

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

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

NOTE 3. VARIABLE INTEREST ENTITIES

Lancaster Power Purchase Agreement

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

Avista Corp. has a variable interest in the PPA. Accordingly, Avista Corp. made an evaluation of which interest holders have the power to direct the activities that most significantly impact the economic performance of the entity and which interest holders have the obligation to absorb losses or receive benefits that could be significant to the entity. Avista Corp. pays a fixed capacity and operations and maintenance payment and certain monthly variable costs under the PPA. Under the terms of the PPA, Avista Corp. makes the dispatch decisions, provides all natural gas fuel and receives all of the electric energy output from the Lancaster Plant. However, Rathdrum Power LLC (the owner) controls the daily operation of the Lancaster Plant and makes operating and maintenance decisions. Rathdrum Power LLC controls all of the rights and obligations of the Lancaster Plant after the expiration of the PPA in 2026. It is estimated that the plant will have 15 to 25 years of useful life after that time. Rathdrum Power LLC bears the maintenance risk of the plant and will receive the residual value of the Lancaster Plant. Avista Corp. has no debt or equity investments in the Lancaster Plant and does not provide financial support through liquidity arrangements or other commitments (other than the PPA). Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Lancaster Plant. Accordingly, neither the Lancaster Plant nor Rathdrum Power LLC is included in Avista Corp.'s condensed consolidated financial statements. The Company has a future contractual obligation of approximately $314 million under the PPA (representing the fixed capacity and operations and maintenance payments through 2026) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

Palouse Wind Power Purchase Agreement

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

The Company evaluated this agreement to determine if it has a variable interest which must be consolidated. Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Palouse Wind facility due to the fact that it pays a fixed price per MWh, which represents the only financial obligation, and does not have any input into the management of the day-to-day operations of the facility. Accordingly, Palouse Wind is not included in Avista Corp.'s condensed consolidated financial statements. The Company has a future contractual obligation of approximately $572 million under the PPA (representing the charges associated with purchasing the energy and renewable attributes through 2042) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

NOTE 4. REDEEMABLE NONCONTROLLING INTERESTS AND SUBSIDIARY ACQUISITIONS

Certain minority shareholders and option holders of Ecova have the right to put their shares back to Ecova at their discretion during an annual put window. 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 March 31, 2013 and December 31, 2012 (dollars in thousands):

	March 31, 2013	December 31, 2012
Stock options and other outstanding redeemable stock	$ 7,970	$ 4,938

On January 31, 2012, Ecova acquired all of the capital stock of LPB Energy Management (LPB), a Dallas, Texas-based energy management company. The cash paid for the acquisition of LPB of $50.6 million was funded by Ecova through $25.0 million of borrowings under its committed credit agreement, a $20.0 million equity infusion from existing shareholders (including Avista Capital and the other owners of Ecova), and available cash. The acquired assets and assumed liabilities of LPB were recorded at their respective estimated fair values as of the date of acquisition. Assets recorded include the following: accounts receivable of $2.5 million, goodwill of $34.0 million, client backlog of $8.2 million (estimated amortization period of 6 years), client relationships of $6.3 million (estimated amortization period of 6 years) and internal use software of $2.5 million (estimated amortization period of 3 to 5 years). These intangible assets are included in intangible assets on the Condensed Consolidated Balance Sheet. Included in the goodwill amount is $1.1 million attributable to assembled workforce that is deductible and will be amortized for tax purposes over a 15-year period and is subject to impairment review annually. The results of operations of LPB are included in the condensed consolidated financial statements beginning February 1, 2012. The sellers of LPB did not receive additional purchase price payments in 2012; however, they have the potential to receive additional purchase price payments of $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 March 31, 2013, Ecova has recorded a contingent liability of $0.3 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 financial condition or results of operations.

NOTE 5. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

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

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

Avista Utilities makes continuing projections of:

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

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

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

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

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

Natural gas resource optimization activities include:

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

The following table presents the underlying energy commodity derivative volumes as of March 31, 2013 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 (1) MWH	Financial (1) MWH	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical MWH	Financial MWH	Physical mmBTUs	Financial mmBTUs
2013	860	2,585	16,717	82,019	641	2,791	3,000	73,896
2014	559	801	6,578	75,187	377	2,305	1,786	44,153
2015	379	737	3,390	53,040	286	1,271	—	43,190
2016	367	—	1,365	16,640	287	675	—	6,060
2017	366	—	—	—	286	—	—	—
Thereafter	583	—	—	—	443	—	—	—

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

The above electric and natural gas derivative contracts will be included in either power supply costs or natural gas supply costs during the period they settle and will be included in the various recovery mechanisms (ERM, PCA, and PGAs), or in the general rate case process, and are expected to be collected through retail rates from customers.

Foreign Currency Exchange Contracts

A significant portion of Avista Utilities' natural gas supply (including fuel for power generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of Avista Utilities' short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices and settled within sixty days with U.S. dollars. Avista Utilities hedges a portion of the foreign currency risk by purchasing Canadian currency contracts when such commodity transactions are initiated. This risk has not had a material effect on the Company's financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations were included with natural gas supply costs for ratemaking. The following table summarizes the foreign currency hedges that the Company has entered into as of March 31, 2013 and December 31, 2012 (dollars in thousands):

	March 31, 2013	December 31, 2012
Number of contracts	22	20
Notional amount (in United States dollars)	$ 4,369	$ 12,621
Notional amount (in Canadian dollars)	4,471	12,502

Interest Rate Swap Agreements

Avista Corp. hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swaps and U.S. Treasury lock agreements. These interest rate swap agreements are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

The following table summarizes the interest rate swaps that the Company has entered into as of March 31, 2013 and December 31, 2012 (dollars in thousands):

	March 31, 2013	December 31, 2012
Number of contracts	2	2
Notional amount	$ 85,000	$ 85,000
Mandatory cash settlement date	June 2013	June 2013
Number of contracts	2	2
Notional amount	$ 50,000	$ 50,000
Mandatory cash settlement date	October 2014	October 2014
Number of contracts	1	1
Notional amount	$ 25,000	$ 25,000
Mandatory cash settlement date	October 2015	October 2015

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.

Derivative Instruments Summary

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of March 31, 2013 (in thousands):

		Fair Value						
Derivative	Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet	Gross Assets Not Offset	Gross Liabilities Not Offset	Net Asset (Liability)
Foreign currency contracts	Other current assets	$ 29	$ (9)	$ —	$ 20	$ —	$ —	$ 20
Interest rate contracts	Other current assets	2,349	—	—	2,349	—	—	2,349
Interest rate contracts	Other property and investments - net	10,555	—	—	10,555	—	—	10,555
Commodity contracts (1)	Current utility energy commodity derivative assets	10,333	(5,627)	—	4,706	(5,090)	4,041	3,657
Commodity contracts (1)	Non-current utility energy commodity derivative assets	2,061	(1,136)	—	925	—	(334)	591
Commodity contracts (1)	Current utility energy commodity derivative liabilities	35,117	(54,404)	6,942	(12,345)	5,090	(4,041)	(11,296)
Commodity contracts (1)	Other non-current liabilities and deferred credits	25,096	(48,213)	3,930	(19,187)	—	334	(18,853)
Total derivative instruments recorded on the balance sheet		$ 85,540	$ (109,389)	$ 10,872	$ (12,977)	$ —	$ —	$ (12,977)

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

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

(1) Avista Corp. has a master netting agreement that governs the transactions of multiple affiliated legal entities under this single master netting agreement. This master netting agreement allows for cross-commodity netting (i.e. netting physical power, physical natural gas, and financial transactions) and cross-affiliate netting for the parties to the agreement. Avista Corp. performs cross-commodity netting for each legal entity that is a party to the master netting agreement for presentation in the Condensed Consolidated Balance Sheets; however, Avista Corp. does not perform cross-affiliate netting because the Company believes that cross-affiliate netting may not be enforceable. Therefore, the requirements for cross-affiliate netting under ASC 210-20-45 are not applicable for Avista Corp.

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 March 31, 2013, the Company had cash deposited as collateral of $21.9 million and letters of credit of $10.1 million outstanding related to its energy derivative contracts. The Condensed Consolidated Balance Sheet at March 31, 2013 reflects the offsetting of $10.9 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 March 31, 2013 was $17.8 million. If the credit-risk-related contingent features underlying these agreements were triggered on March 31, 2013, the Company could be required to post $11.5 million of additional collateral to its counterparties.

Credit Risk

Credit risk relates to the potential losses that the Company would incur as a result of non-performance by counterparties of their contractual obligations to deliver energy or make financial settlements. The Company often extends credit to counterparties and customers and is exposed to the risk that it may not be able to collect amounts owed to the Company. Credit risk includes potential counterparty default due to circumstances:

- relating directly to it,
- caused by market price changes, and
- relating to other market participants that have a direct or indirect relationship with such counterparty.

Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established. Should a counterparty fail to perform, the Company may be required to honor the underlying commitment or to replace existing contracts with contracts at then-current market prices.

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

The Company seeks to mitigate bilateral credit risk by:

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

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

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

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

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

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

NOTE 6. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering substantially all regular full-time employees at Avista Utilities. Individual benefits under this plan are based upon the employee’s years of service, date of hire and average compensation as specified in the plan. The Company’s funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $14.7 million in cash to the pension plan for the three months ended March 31, 2013 . The Company expects to contribute $44 million in cash to the pension plan in 2013. The Company contributed $44 million in cash to the pension plan in 2012.

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 months ended March 31 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2013	2012	2013	2012
Service cost	$ 4,743	$ 3,791	$ 1,032	$ 689
Interest cost	5,978	6,109	1,390	1,281
Expected return on plan assets	(6,900)	(6,000)	(400)	(375)
Transition obligation recognition	—	—	—	126
Amortization of prior service cost	75	75	(37)	(38)
Net loss recognition	3,547	2,757	1,521	1,312
Net periodic benefit cost	$ 7,443	$ 6,732	$ 3,506	$ 2,995

NOTE 7. COMMITTED LINES OF CREDIT

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million 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 March 31, 2013, the Company was in compliance with this covenant.

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

	March 31, 2013	December 31, 2012
Borrowings outstanding at end of period	$ 52,500	$ 52,000
Letters of credit outstanding at end of period	$ 12,608	$ 35,885
Average interest rate on borrowings at end of period	1.17%	1.12%

As of March 31, 2013 the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Condensed Consolidated Balance Sheet.

Ecova

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

The committed line of credit agreement contains customary covenants and default provisions, including a covenant which requires that Ecova's "Consolidated Total Funded Debt to EBITDA Ratio" (as defined in the credit agreement) must be 2.50 to 1.00 or less, with provisions in the credit agreement allowing for a temporary increase of this ratio if a qualified acquisition is consummated by Ecova. In addition, Ecova's "Consolidated Fixed Charge Coverage Ratio" (as defined in the credit agreement) must be greater than 1.50 to 1.00 as of the last day of any fiscal quarter. As of March 31, 2013, Ecova was in compliance with these covenants.

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

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

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

NOTE 8. LONG-TERM DEBT

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

Maturity Year	Description	Interest Rate	March 31, 2013	December 31, 2012
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
2047	First Mortgage Bonds	4.23%	80,000	80,000
	Total secured long-term debt		1,336,700	1,336,700
	Other long-term debt and capital leases		4,991	5,092
	Settled interest rate swaps (3)		(27,460)	(27,900)
	Unamortized debt discount		(1,411)	(1,453)
	Total		1,312,820	1,312,439
	Secured Pollution Control Bonds held by Avista Corporation (1) (2)		(83,700)	(83,700)
	Current portion of long-term debt		(50,354)	(50,372)
	Total long-term debt		$ 1,178,766	$ 1,178,367

(1) In December 2010, $66.7 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due 2032, which had been held by Avista Corp. since 2008, were refunded by a new bond issue (Series 2010A). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Condensed Consolidated Balance Sheet.

(2) In December 2010, $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds, (Avista Corporation Colstrip Project) due 2034, which had been held by Avista Corp. since 2009, were refunded by a new bond issue (Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, the bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Condensed Consolidated Balance Sheet.

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

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

	March 31, 2013		December 31, 2012	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 951,000	$ 1,149,134	$ 951,000	$ 1,164,639
Long-term debt (Level 3)	302,000	311,479	302,000	320,892
Nonrecourse long-term debt (Level 3)	29,181	31,201	32,803	35,297
Long-term debt to affiliated trusts (Level 3)	51,547	37,109	51,547	43,686

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

The following table discloses by level within the fair value hierarchy the Company’s assets and liabilities measured and reported on the Condensed Consolidated Balance Sheets as of March 31, 2013 and December 31, 2012 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
March 31, 2013					
Assets:					
Energy commodity derivatives	$ —	$ 72,555	$ —	$ (66,924)	$ 5,631
Level 3 energy commodity derivatives:					
Power exchange agreements	—	—	52	(52)	—
Foreign currency derivatives	—	29	—	(9)	20
Interest rate swaps	—	12,904	—	—	12,904
Investments and funds held for clients:					
Securities available for sale:					
U.S. government agency	—	64,505	—	—	64,505
Municipal	—	3,628	—	—	3,628
Corporate fixed income – financial	—	4,011	—	—	4,011
Corporate fixed income – industrial	—	3,917	—	—	3,917
Certificate of deposits	—	1,016	—	—	1,016
Funds held in trust account of Spokane Energy	1,600	—	—	—	1,600
Deferred compensation assets:					
Fixed income securities (2)	2,093	—	—	—	2,093
Equity securities (2)	6,183	—	—	—	6,183
Total	$ 9,876	$ 162,565	$ 52	$ (66,985)	$ 105,508
Liabilities:					
Energy commodity derivatives	$ —	$ 89,674	$ —	$ (77,796)	$ 11,878
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	1,991	—	1,991
Power exchange agreements	—	—	16,515	(52)	16,463
Power option agreements	—	—	1,200	—	1,200
Foreign currency derivatives	—	9	—	(9)	—
Total	$ —	$ 89,683	$ 19,706	$ (77,857)	$ 31,532

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

(1) The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a legally enforceable master netting agreement exists. In addition, the Company nets derivative assets and derivative liabilities against any payables and receivables for cash collateral held or placed with these same counterparties.

(2) These assets are trading securities and are included in other property and investments-net on the Condensed Consolidated Balance Sheets.

Avista Corp. enters into forward contracts to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. These contracts are entered into as part of Avista Corp.'s management of loads and resources and certain contracts are considered derivative instruments. The difference between the amount of derivative assets and liabilities disclosed in respective levels and the amount of derivative assets and liabilities disclosed on the Condensed Consolidated Balance Sheets is due to netting arrangements with certain counterparties. The Company uses quoted market prices and forward price curves to estimate the fair value of utility derivative commodity instruments included in Level 2. In particular, electric derivative valuations are performed using broker quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange (NYMEX) pricing for similar instruments, adjusted for basin differences, using broker quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

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

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

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 2013, and 3) volatility rates for periods beyond April 2016. Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, changes in overall commodity market prices and volatility rates are accompanied by directionally similar changes in the strike price and volatility assumptions used in the calculation.

For 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 March 31, 2013 (dollars in thousands):

	Fair Value (Net) at March 31, 2013	Valuation Technique	Unobservable Input	Range
Power exchange agreements	$ (16,463)	Surrogate facility pricing	O&M charges	$30.49-$53.82/MWh (1)
			Escalation factor	5% - 2013 to 2015
				3% - 2016 to 2019
			Transaction volumes	365,619 - 379,156 MWhs
Power option agreements	(1,200)	Black-Scholes-Merton	Strike price	$58.25/MWh - 2014
				$73.92/MWh - 2019
			Delivery volumes	128,491 - 287,147 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreements	(1,991)	Internally derived weighted average cost of gas	Forward purchase prices	$3.83 - $3.85/mmBTU
			Forward sales prices	$3.89 - $4.80/mmBTU
			Purchase volumes	128,884 - 310,000 mmBTUs
			Sales volumes	139,980 - 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 quoted volatility rates of 0.28 for 2013 to 0.22 in April 2016.

Avista Corp.'s risk management team and accounting team are responsible for developing the valuation methods described above and both groups report to the Chief Financial Officer. The valuation methods, the significant inputs, and the resulting fair values described above are reviewed on at least a quarterly basis by the risk management team and the accounting team to ensure they provide a reasonable estimate of fair value each reporting period.

The following table presents activity for energy commodity derivative assets (liabilities) measured at fair value using significant unobservable inputs (Level 3) for the three months ended March 31, 2013 and 2012 (dollars in thousands):

	Natural Gas Exchange Agreements	Power Exchange Agreements	Power Option Agreements	Total
Three months ended March 31, 2013:				
Balance as of January 1, 2013	$ (2,379)	$ (18,692)	$ (1,480)	$ (22,551)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	750	24	280	1,054
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(362)	2,205	—	1,843
Transfers to/from other categories	—	—	—	—
Ending balance as of March 31, 2013	$ (1,991)	$ (16,463)	$ (1,200)	$ (19,654)
Three months ended March 31, 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)	290	(10,914)	273	(10,351)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(956)	2,252	—	1,296
Transfers from other categories	—	—	—	—
Ending balance as of March 31, 2012	$ (2,354)	$ (18,572)	$ (987)	$ (21,913)

(1) The UTC and the IPUC issued accounting orders authorizing Avista Utilities to offset commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of 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 SHAREHOLDERS

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

	2013	2012
Numerator:		
Net income attributable to Avista Corporation shareholders	$ 42,341	$ 38,388
Subsidiary earnings adjustment for dilutive securities	(43)	—
Adjusted net income attributable to Avista Corporation shareholders for computation of diluted earnings per common share	$ 42,298	$ 38,388
Denominator:		
Weighted-average number of common shares outstanding-basic	59,866	58,581
Effect of dilutive securities:		
Performance and restricted stock awards	32	344
Stock options	—	25
Weighted-average number of common shares outstanding-diluted	59,898	58,950
Potential shares excluded in calculation (1)	—	—
Earnings per common share attributable to Avista Corporation shareholders:		
Basic	$ 0.71	$ 0.66
Diluted	$ 0.71	$ 0.65

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

NOTE 11. COMMITMENTS AND CONTINGENCIES

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

Federal Energy Regulatory Commission Inquiry

In April 2004, the Federal Energy Regulatory Commission (FERC) approved the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) between Avista Corp. doing business as Avista Utilities, Avista Energy and the FERC's Trial Staff which stated that there was: (1) no evidence that any executives or employees of Avista Utilities or Avista Energy knowingly engaged in or facilitated any improper trading strategy during 2000 and 2001; (2) no evidence that Avista Utilities or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; and (3) no finding that Avista Utilities or Avista Energy withheld relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001 (Trading Investigation). 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 directed 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 March 31, 2013, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from the defaulting parties.

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

A FERC hearing commenced on April 11, 2012 and concluded on July 19, 2012. On August 27, 2012, the Presiding Administrative Law Judge issued a partial initial decision granting Avista Utilities' motion for summary disposition, based on the stipulation by the California Parties that there are no allegations of tariff violations made against Avista Utilities in this proceeding and therefore no tariff violations by Avista Utilities that affected the market clearing price in any hour during the Summer Period. On November 2, 2012, 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. On December 3, 2012, the California Parties filed a request for clarification and rehearing of the November 2, 2012 order. On February 15, 2013, the Administrative Law Judge issued an initial decision finding that certain Respondents committed various tariff and other violations that affected the market clearing price in the California organized markets during the Summer Period. The tariff violations identified for Avista Energy are type II and III bidding violations; false export violations; and selling ancillary services without market-based rate authority. The initial decision did not discuss evidence offered by Avista Energy, on an hour-by-hour basis, rebutting the alleged violations. With respect to Avista Energy's one exchange transaction with the CalISO during the Refund Period, the judge made no findings with respect to the justness and reasonableness of that transaction, but nonetheless determined that Avista Energy owed approximately $0.2 million in refunds with regard to the transaction. Avista Energy filed its brief on exceptions to the initial decision on April 12, 2013. Briefs opposing exceptions are due June 7, 2013.

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

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. In August 2007, the Ninth Circuit found that the FERC, in denying the request for refunds, had failed to take into account new evidence of market manipulation in the California energy market and its potential ties to the Pacific Northwest energy market and that such failure was arbitrary and capricious and, accordingly, remanded the case to the FERC, stating that the FERC's findings must be reevaluated in light of the evidence. In addition, the Ninth Circuit concluded that the FERC abused its discretion in denying potential relief for transactions involving energy that was purchased by 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 on Remand 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. The Order on Remand also allows participants to supplement the record with additional evidence on CERS transactions in the Pacific Northwest spot market from January 18, 2001 to June 20, 2001. The Order on Remand states that parties seeking refunds must submit evidence demonstrating that specific unlawful market activity occurred, and must demonstrate that such activity directly affected negotiations with respect to the specific contract rate about which they complain. Simply alleging a general link between the dysfunctional spot market in California and the Pacific Northwest spot market will not be sufficient to establish a causal connection between a particular seller's alleged unlawful activities and the specific contract negotiations at issue.

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

The claimants filed notice of their claims on August 17, 2012, and they filed their direct testimony on September 21, 2012. The respondents filed their answering testimony on December 17, 2012 and the FERC Trial Staff filed its answering testimony on February 5, 2013. The claimants filed their rebuttal testimony on March 12, 2013.

On April 5, 2013, the FERC issued an Order on Rehearing of the October 3, 2011 Order on Remand. The Order on Rehearing reaffirmed the rulings in the Order on Remand about the scope of the hearing and permissible evidence, rejecting various challenges by the claimants. The Order on Rehearing expanded the scope of the proceeding to permit parties to submit evidence on transactions during the period from January 1, 2000 through and including June 20, 2001. On April 11, 2013, the California Parties filed a petition for review of the October 3, 2011 order and the April 5, 2013 order in the Ninth Circuit.

On April 17, 2013, the Chief Administrative Law Judge issued an order adopting the recommendations of the Presiding Administrative Law Judge that, in light of the FERC's April 5, 2013 order, the hearing date should be continued until August 27, 2013 to accommodate the need for additional discovery and filing of testimony related to the expanded scope of the proceeding. Seattle is the only claimant affected by this ruling, as CERS did not come into existence until January 2001. With regard to the new expanded scope of the proceeding, Seattle's statement of claims is due May 17, 2013 and direct testimony is due June 3, 2013. Respondents' answering testimony is due June 24, 2013 and the FERC Trial Staff's answering testimony is due July 11, 2013. Rebuttal testimony is due July 26, 2013.

Both Avista Utilities and Avista Energy were buyers and sellers of energy in the Pacific Northwest energy market during the period between January 1, 2000 and June 20, 2001, and are subject to potential claims in this proceeding, 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. On March 13, 2013, the Ninth Circuit issued an order setting a briefing schedule, such that petitioners' joint opening brief is due June 17, 2013; respondents' answering brief is due August 16, 2013; respondent-intervenors' joint brief is due September 9, 2013; and petitioners' optional joint reply brief is due October 9, 2013.

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

Colstrip Generating Project - Complaint Alleging Water Pollution

In March 2007, two families that own property near the holding ponds from Units 3 & 4 of the Colstrip Generating Project (Colstrip) filed a complaint against the owners of Colstrip and Hydrometrics, Inc. in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs alleged that the holding ponds and remediation activities adversely impacted their property. They alleged contamination, decrease in water tables, reduced flow of streams on their property and other similar impacts to their property. They also sought punitive damages, 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 subsequently appealed the court's decision and, on December 31, 2012, the Montana Supreme Court issued its decision, holding that the District Court properly granted the motion to enforce the settlement agreement. A petition for rehearing before the Supreme Court was denied on February 5, 2013. Under the settlement, Avista Corp.'s portion of payment (which was accrued in 2010) to the plaintiffs was not material to its financial condition, results of operations or cash flows.

Sierra Club and Montana Environmental Information Center Litigation

On March 6, 2013, the Sierra Club and Montana Environmental Information Center (collectively "Plaintiffs"), filed a Complaint (Complaint) in the United States District Court for the District of Montana, Billings Division, against the owners of the Colstrip Generating Project (Colstrip). Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The other Colstrip co-owners are PPL Montana, Puget Sound Energy, Portland General Electric Company, NorthWestern Energy and PacifiCorp. The Complaint alleges certain violations of the Clean Air Act, including the New Source Review, Title V and opacity requirements. The Plaintiffs request that the Court grant injunctive and declaratory relief, impose civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require payment of Plaintiffs' costs of litigation and attorney fees. Avista Corp. is evaluating the allegations set forth in the Complaint and cannot at this time predict the outcome of the 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 issued a notice of its plan to make a finding of No Further Action in November 2012. Should the EPA make a No Further Action determination, the EPA stated it would then propose removal of the site from the National Priority List. Based on the review of its records related to Harbor Oil, the Company does not believe it is a significant 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 (Ecology), the Company has participated in the Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On May 20, 2010, the EPA approved the TMDL and on May 27, 2010, Ecology filed an amended 401 Water Quality Certification with the FERC for inclusion into the license. The amended 401 Water Quality Certification includes the Company's level of responsibility, as defined in the TMDL, for low dissolved oxygen levels in Lake Spokane. The Company submitted a draft Water Quality Attainment Plan for Dissolved Oxygen to Ecology in May 2012 and this was approved by Ecology in September 2012. This plan was subsequently approved by the FERC. The Company will begin to implement this plan, and management believes costs will not be material. On July 16, 2010, the City of Post Falls and the Hayden Area Regional Sewer Board filed an appeal with the United States District Court for the District of Idaho with respect to the EPA's approval of the TMDL. The Company, the City of Coeur d'Alene, Kaiser Aluminum and the Spokane River Keeper subsequently moved to intervene in the appeal. In September 2011, the EPA issued a stay to the litigation that will be in effect until either the permits are issued and all appeals and challenges are complete or the court lifts the stay. The stay is still in effect.

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

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels in the Clark Fork River exceed state of Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement as incorporated in Avista Corp.'s FERC license for the Clark Fork Project, Avista Corp. has worked in consultation with agencies, tribes and other stakeholders to address this issue. In the second quarter of 2011, the Company completed preliminary feasibility assessments for several alternative abatement measures. In 2012, Avista Corp., with the approval of the Clark Fork Management Committee (created under the Clark Fork Settlement Agreement), moved forward to test one of the alternatives by constructing a spill crest modification on a single spill gate. The modification will be tested in 2013 to evaluate whether this approach will provide significant TDG reduction, and whether it could be applied to other spill gates. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the USFWS listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company evaluated the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. Fishway designs for Cabinet Gorge are still being finalized. Construction cost estimates and schedules will be developed later in 2013. Fishway design for Noxon Rapids has also been initiated, and is still in early stages.

In January 2010, the USFWS revised its 2005 designation of critical habitat for the bull trout to include the lower Clark Fork River as critical habitat. The Company believes its ongoing efforts through the Clark Fork Settlement Agreement continue to effectively address issues related to bull trout. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to fish passage at Cabinet Gorge and Noxon Rapids.

Aluminum Recycling Site

In October 2009, the Company (through its subsidiary Pentzer Venture Holdings II, Inc. (Pentzer)) received notice from Ecology 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 Ecology as “Aluminum Recycling - Trentwood.” Operators of the UPR property maintained piles of aluminum dross, which designate 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 Ecology's proposed findings in November 2009. In December 2009, Pentzer received notice from Ecology that it had been designated as a potentially liable party for any hazardous substances located on this site. UPR completed a Remedial Investigation/Feasibility Study during 2011, which was approved by Ecology in 2012. 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. The Company's management evaluates performance based on income (loss) from operations before income taxes as well as net income (loss) attributable to Avista Corp. shareholders. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. Avista Utilities' business is managed based on the total regulated utility operation. Ecova is a provider of 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. 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 March 31, 2013:						
Operating revenues	$ 431,577	$ 42,407	$ 9,372	$ 51,779	$ (450)	$ 482,906
Resource costs	229,630	—	—	—	—	229,630
Other operating expenses	65,444	35,990	9,795	45,785	(450)	110,779
Depreciation and amortization	27,935	3,493	190	3,683	—	31,618
Income from operations	82,751	2,924	(613)	2,311	—	85,062
Interest expense (2)	18,770	444	673	1,117	(77)	19,810
Income taxes	24,780	984	(528)	456	—	25,236
Net income (loss) attributable to Avista Corporation shareholders	42,250	1,198	(1,107)	91	—	42,341
Capital expenditures	70,645	794	25	819	—	71,464
For the three months ended March 31, 2012:						
Operating revenues	$ 405,910	$ 37,010	$ 9,787	$ 46,797	$ (450)	$ 452,257
Resource costs	211,012	—	—	—	—	211,012
Other operating expenses (3)	65,322	35,774	8,717	44,491	(450)	109,363
Depreciation and amortization	27,318	2,836	168	3,004	—	30,322
Income from operations (3)	77,092	(1,600)	902	(698)	—	76,394
Interest expense (2)	18,046	360	965	1,325	(94)	19,277
Income taxes	21,726	(381)	(207)	(588)	—	21,138
Net income (loss) attributable to Avista Corporation shareholders	39,477	(826)	(263)	(1,089)	—	38,388
Capital expenditures	57,771	1,142	2	1,144	—	58,915
Total Assets:						
As of March 31, 2013:	$ 3,878,347	$ 361,376	$ 92,415	$ 453,791	$ —	$ 4,332,138
As of December 31, 2012:	$ 3,894,821	$ 322,720	$ 95,638	$ 418,358	$ —	$ 4,313,179

(1) Intersegment eliminations reported as operating revenues and resource costs represent intercompany purchases and sales of electric capacity and energy. Intersegment eliminations reported as interest expense represent intercompany interest.

(2) Including interest expense to affiliated trusts.

(3) Includes an immaterial correction of an error related to the reclassification of certain operating expenses from other expense-net to utility and non-utility other operating expenses and utility taxes other than income taxes. This correction did not have an impact on net income or earnings per share. See Note 1 for further information regarding this reclassification.

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 March 31, 2013, and the related condensed consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for the three-month periods ended March 31, 2013 and 2012. These interim financial statements are the responsibility of the Company's management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our reviews, we are not aware of any material modifications that should be made to such condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Avista Corporation and subsidiaries as of December 31, 2012, and the related consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for the year then ended (not presented herein); and in our report dated February 26, 2013, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2012 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP

Seattle, Washington
May 3, 2013

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

Business Segments

We have two reportable business segments as follows:

- **Avista Utilities** – an operating division of Avista Corp. that comprises our regulated utility operations. Avista Utilities generates, transmits and distributes electricity and distributes natural gas. The utility also engages in wholesale purchases and sales of electricity and natural gas.
- **Ecova** – an indirect subsidiary of Avista Corp. (78.9 percent owned as of March 31, 2013) provides energy efficiency and cost management programs and services for multi-site customers and utilities throughout North America. Ecova's service lines include expense management services for utility and telecom needs as well as strategic energy management and efficiency services that include procurement, conservation, performance reporting, financial planning, facility optimization and continuous monitoring, and energy efficiency program management for commercial enterprises and utilities.

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

The following table presents net income (loss) attributable to Avista Corp. shareholders for each of our business segments (and the other businesses) for the three months ended March 31 (dollars in thousands):

	2013	2012
Avista Utilities	$ 42,250	$ 39,477
Ecova	1,198	(826)
Other	(1,107)	(263)
Net income attributable to Avista Corporation shareholders	$ 42,341	$ 38,388

Executive Level Summary

Overall

Net income attributable to Avista Corporation shareholders was $42.3 million for the three months ended March 31, 2013, an increase from $38.4 million for the three months ended March 31, 2012. This was due to an increase in earnings at Avista Utilities and Ecova, offset by a decrease at our other businesses. Earnings at Avista Utilities increased primarily due to the implementation of general rate increases partially offset by higher depreciation and amortization, and taxes other than income taxes. Net income at Ecova increased due to increased revenue associated with new services and higher volumes in expense and data management services and energy management services. This was partially offset by increased depreciation and amortization and slightly higher other operating expenses. Net losses at our other subsidiaries increased due to an impairment loss of $0.5 million pre-tax ($0.3 million after-tax) associated with our investment in an energy storage company, increased costs associated with strategic investments and increased litigation costs related to the previous operations of Avista Energy. These losses were partially offset by positive earnings at METALfx. These results, including a quantification of their respective impacts, are discussed in detail below.

Avista Utilities

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

- weather conditions,
- regulatory decisions, allowing our utility to recover costs, including purchased power and fuel costs, on a timely basis, and to earn a reasonable return on investment,
- the price of natural gas in the wholesale market, including the effect on the price of fuel for generation, and
- the price of electricity in the wholesale market, including the effects of weather conditions, natural gas prices and other factors affecting supply and demand.

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 Washington on January 1, 2012 and January 1, 2013, and in Oregon effective June 1, 2012. In March 2013, the IPUC approved a settlement agreement in our Idaho general rate cases, which were originally filed on October 11, 2012, that provides for a natural gas rate increase effective April 1, 2013, and electric and natural gas rate increases effective October 1, 2013 (see further discussion below under "Idaho General Rate Cases"). In December 2012, the UTC approved a settlement agreement in our Washington general rate cases, which were originally filed on April 2, 2012, that provides for electric and natural gas rate increases effective January 1, 2013 and January 1, 2014 (see further discussion below under "Washington General Rate Cases").

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 $70.6 million for the first quarter of 2013. We expect utility capital expenditures to be about $260 million for each of 2013, 2014, and 2015. These estimates of capital expenditures are subject to continuing review and adjustment (see discussion under “Avista Utilities Capital Expenditures”).

An agreement with one of our largest electric customers, which consumes approximately 100 aMWs per year, is expiring on June 30, 2013. We have negotiated a new agreement with this customer that is expected to become effective July 1, 2013 and has a five-year term. A Joint Petition for approval of the new agreement was filed, by Avista and the customer, with the IPUC on April 12, 2013. Under the new agreement, we expect a decrease in annual revenues of approximately $21 million and a decrease in resource costs of approximately $19.1 million. In the Joint Petition we have proposed that any change in revenues and expenses associated with the new service agreement, as compared with the revenues and expenses included in the last rate case for this customer, be tracked through the PCA at 100 percent, such that there would be no impact to our earnings from the new agreement.

Ecova

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.

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

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

Liquidity and Capital Resources

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

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2017. As of March 31, 2013, there were $52.5 million of cash borrowings and $12.6 million in letters of credit outstanding leaving $334.9 million of available liquidity under this line of credit.

Ecova has a $125.0 million committed line of credit agreement with various financial institutions that has an expiration date of July 2017. As of March 31, 2013, Ecova had $54.0 million of borrowings outstanding under its committed line of credit agreement. Based on certain covenant conditions contained in the credit agreement, at March 31, 2013, Ecova could borrow an additional $11.6 million and still be compliant with its covenants. The covenant restrictions are calculated on a rolling twelve month basis, so this additional borrowing capacity could increase or decrease or Ecova could be required to pay down the outstanding debt as future results change. See further discussion of the specific covenants below under "Ecova Credit Agreement."

There are $50.0 million in First Mortgage Bonds maturing in December 2013 and we expect to issue up to $100.0 million of long-term debt during the second half of 2013.

In August 2012, we entered into two sales agency agreements under which we may issue up to 2.7 million shares of our common stock from time to time. In 2013, we have not sold any shares under these agreements and as of March 31, 2013, we had 1.8 million shares available to be issued under these agreements.

During 2013, we expect to issue up to $50.0 million of common stock in order to maintain our capital structure at an appropriate level for our business, with the majority of the issuances in the second half of the year. After considering the issuances of long-term debt and common stock during 2013, we expect net cash flows from operating activities, together with cash available under our $400.0 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 April 2012 (which were settled with new rates effective January 1, 2013 and January 1, 2014) and Idaho in October 2012 (which were settled with new rates effective April 1, 2013 and October 1, 2013).

Washington General Rate Cases

A settlement agreement with the UTC in December 2011 regarding electric and natural gas general rate cases filed in May 2011 provided for the deferral of certain generation plant maintenance costs. 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. These maintenance costs may be much higher in some years because certain significant maintenance procedures are less frequent than annual and, therefore, may not be properly represented in test year expenses used in our filed rate requests. For 2011 and 2012 the Company compared actual, non-fuel, maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of baseline maintenance expenses used to establish base retail rates, and deferred the difference. This deferral occurred 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 $3.8 million as of March 31, 2013 compared to a regulatory asset of $4.0 million as of December 31, 2012. 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 will terminate on December 31, 2012, with the four-year amortization of the 2011 and 2012 deferrals to conclude in 2015 and 2016, respectively.

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

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

The UTC Order approving the settlement agreement included certain conditions. The new retail rates to become effective January 1, 2014 will be temporary rates, and on January 1, 2015 electric and natural gas base rates will revert back to 2013 levels absent any intervening action from the UTC. Included in the original settlement agreement is a provision that we will not file a general rate case in Washington seeking new rates to take effect before January 1, 2015. We can, however, make a filing prior to January 1, 2015, but new rates resulting from the filing would not take effect prior to January 1, 2015. We currently intend to file a general rate case in early 2014 with proposed rates that would take effect on January 1, 2015. This provision does not preclude us from filing annual rate adjustments such as the PCA and the PGA.

In addition, in its Order, the UTC found that much of the approved base rate increases is justified by the planned capital expenditures necessary to upgrade and maintain our utility facilities. If these capital projects are not completed to a level that was contemplated in the original settlement agreement, this could result in base rates which are considered too high by the UTC. As a result, we must file capital expenditure progress reports with the UTC on a periodic basis so that the UTC can monitor the capital expenditures and ensure they are in line with those contemplated in the settlement agreement. We expect total utility capital expenditures among all jurisdictions to be approximately $260 million for each of 2013, 2014, and 2015.

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.

Idaho General Rate Cases

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

On March 27, 2013, the IPUC approved a settlement agreement in our electric and natural gas general rate cases filed in October 2012. As agreed to in the settlement, new rates will be implemented in two phases: April 1, 2013 and October 1, 2013. Effective April 1, 2013, base rates increased for our Idaho natural gas customers by an overall 4.9 percent (designed to increase annual revenues by $3.1 million). There was no change in base electric rates on April 1, 2013. However, the settlement agreement provided for the recovery of the costs of the Palouse Wind Project through the PCA mechanism until these costs are reflected in base retail rates in our next general rate case.

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

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

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

Also included in the settlement agreement is a provision that we may file a general rate case in Idaho in 2014; however, new rates resulting from the filing would not take effect prior to January 1, 2015.

The settlement agreement provided for an authorized return on equity of 9.8 percent and an equity ratio of 50.0 percent.

The settlement also includes an after-the-fact earnings test for 2013 and 2014, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earns more than a 9.8 percent return on equity, we will refund to customers 50 percent of any earnings above the 9.8 percent.

Bonneville Power Administration Reimbursement and Reardan Wind Generation Project

On April 12, 2013, we filed with the UTC a Petition for an order that authorizes certain accounting and ratemaking treatment related to two issues. The first issue relates to transmission revenues associated with a settlement between Avista Corp. and the Bonneville Power Administration (Bonneville), whereby Bonneville reimbursed the Company $11.7 million for Bonneville's past use of Avista's transmission system. The second issue relates to $4.3 million of costs we incurred over the past several years for the development of a wind generation project site near Reardan, Washington. We are proposing to retain $7.6 million of the Bonneville settlement payment, representing the portion of the settlement allocable to our Washington business, less Washington's portion of the Reardan project costs of $2.6 million, to fully offset the portion of the Reardan project allocable to our Washington business, or a net total of $5.0 million. In addition, Bonneville has agreed to pay $0.3 million monthly for the future use of our transmission system. We are proposing to separately track and defer for the customers' benefit, the Washington portion of these future revenue payments in 2013 and 2014 ($2.1 million annually) to be used to offset our electric general rate increase effective January 1, 2014. To the extent actual revenues from Bonneville in 2013 and 2014 differ from those refunded to customers in 2014, the difference will be added to or subtracted from the ERM balance. In Idaho, under the terms of the approved rate case settlement, 90 percent of the portion of the BPA settlement allocable to our Idaho business ($4.1 million) will be credited back to customers over 15 months, beginning October 2013, and we will amortize the Idaho portion of Reardan costs ($1.7 million, including $1.3 million of incurred costs and $0.4 million of equity-related AFUDC) over a two-year period, beginning April 2013.

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to our customers with no change in gross margin (operating revenues less resource costs) or net income. 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. In Oregon, we absorb (cost or benefit) 10 percent of the difference between actual and projected gas costs for supply that is not hedged. Total net deferred natural gas costs were a liability of $10.1 million as of March 31, 2013 and a liability of $6.9 million as of December 31, 2012.

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

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

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used to track certain differences between actual power supply costs, net of the margin on wholesale sales and sales of fuel, and the amount included in base retail rates for our Washington customers. Total net deferred power costs under the ERM were a liability of $21.7 million as of March 31, 2013, compared to a liability of $22.2 million as of December 31, 2012, and these balances represent the customer portion of the deferred power costs. As part of the approved Washington general rate case settlement in December 2012, during 2013 a one-year credit of $4.4 million will be returned to electric customers from the existing ERM deferral balance to reduce the net average electric rate increase impact to customers in 2013. Additionally, during 2014 a one-year credit up to $9.0 million will be returned to electric customers from the then-existing ERM deferral balance, if such funds are available, so the net average electric rate increase impact to customers effective January 1, 2014 would also be reduced. The credits to customers from the ERM balances would not impact our net income.

The difference in net power supply costs under the ERM primarily results from changes in:

- short-term wholesale market prices and sales and purchase volumes,
- the level of hydroelectric generation,
- the level of thermal generation (including changes in fuel prices),
- the net value from optimization activities related to our generating resources, and
- retail loads.

Under the ERM, we absorb the cost or receive the benefit from the initial amount of power supply costs in excess of or below the level in retail rates, which is referred to as the deadband. The annual (calendar year) deadband amount is currently $4.0 million. We incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. We share annual power supply cost variances between $4.0 million and $10.0 million with customers. There is a 50 percent customers/50 percent Company sharing ratio when actual power supply expenses are higher (surcharge to customers) than the amount included in base retail rates within this band. There is a 75 percent customers/25 percent Company sharing ratio when actual power supply expenses are lower (rebate to customers) than the amount included in base retail rates within this band. To the extent that the annual power supply cost variance from the amount included in base rates exceeds $10.0 million, there is a 90 percent customers/10 percent Company sharing ratio of the cost variance.

The following is a summary of the ERM:

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
within +/- $0 to $4 million (deadband)	0%	100%
higher by $4 million to $10 million	50%	50%
lower by $4 million to $10 million	75%	25%
higher or lower by over $10 million	90%	10%

Under the ERM, we make an annual filing on or before April 1 of each year to provide the opportunity for the UTC staff and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. The ERM provides for a 90-day review period for the filing; however, the period may be extended by agreement of the parties or by UTC order.

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

We have a PCA mechanism in Idaho that allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. The October 1 rate adjustments recover or rebate power supply costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a liability of $5.3 million as of March 31, 2013 compared to a liability of $5.1 million as of December 31, 2012.

Natural Gas Safety Regulations

On February 3, 2012, President Obama signed into law the "Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011" mandating new regulations be created to address public safety concerns. 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. The U.S. Department of Transportation has already proposed rules that address many areas of the new Act and we have already complied with many of the requirements of this legislation. We are still evaluating the Act and waiting for further rules and clarifications surrounding certain portions of this Act; however, we expect that any additional compliance required would not have a significant impact 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.

2013 compared to 2012

Utility revenues increased $25.7 million, after elimination of intracompany revenues of $41.4 million for the first quarter of 2013 and $27.6 million for the first quarter of 2012. Including intracompany revenues, electric revenues increased $31.7 million and natural gas revenues increased $7.8 million. Wholesale electric revenues increased $15.1 million and sales of fuel increased $6.7 million. Other electric revenues increased $12.7 million primarily due to the receipt of revenue from Bonneville for past use of our electric transmission system. Retail electric revenues decreased $2.8 million primarily due to a change in revenue mix and a decrease in retail rates from items that do not impact net income (including the ERM and demand side management programs). Retail natural gas revenues decreased $8.3 million due to a decrease in rates from PGAs, while wholesale natural gas revenues increased $15.4 million.

Ecova revenues increased $5.4 million to $42.4 million primarily as a result of an increase in revenues associated with new services, expense and data management services, and energy management services.

Utility resource costs increased $18.6 million, after elimination of intracompany resource costs of $41.4 million for 2013 and $27.6 million for 2012. Including intracompany resource costs, electric resource costs increased $27.1 million and natural gas resource costs increased $5.3 million. The increase in electric resource costs was primarily due to an increase in regulatory amortizations associated with the deferral of the Washington portion of the Bonneville revenue for past use of our transmission system pending approval from the UTC and the deferral of 90 percent of the Idaho portion of the Bonneville revenue for future refund to our Idaho customers. In addition, there was an increase in power purchased, fuel costs (due to higher thermal generation and higher natural gas fuel prices) and other fuel costs (represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation as part of the resource optimization process). The increase in natural gas resource costs was primarily due to an increase in natural gas prices and volumes.

Utility other operating expenses increased $0.1 million primarily due to increased pensions and other postretirement benefits, increased other production and gas distribution costs, offset by a decrease in outside services and decreased electric maintenance costs.

Utility depreciation and amortization increased $0.6 million driven by additions to utility plant.

Taxes other than income taxes increased $0.7 million primarily due to increased property taxes.

Ecova other operating expenses increased $0.2 million primarily reflecting increased costs associated with higher revenue volumes in the expense and data management services and new services, and these were partially offset by a decrease in integration and acquisition costs of $1.5 million, which Ecova incurred during the first quarter of 2012 and this did not reoccur during 2013.

Ecova depreciation and amortization increased $0.7 million primarily due to the amortization of intangibles recorded in connection with Ecova's acquisition of LPB.

Other non-utility operating expenses increased $1.1 million primarily due to increased outside service and other miscellaneous expense of $0.3 million and increased consulting services and other corporate costs of $0.4 million.

Interest expense increased $0.6 million primarily due to the issuance of long-term debt in November 2012 that increased the balance of long-term debt outstanding.

Other income-net increased $0.4 million primarily due to an increase in equity-related AFUDC of $0.5 million and a decrease in losses on investments (exclusive of impairments) of $0.6 million. These increases were offset by an impairment loss of $0.5 million pre-tax ($0.3 million after-tax) associated with our investment in an energy storage company.

Income taxes increased $4.1 million and our effective tax rate was 36.9 percent for the first quarter of 2013 compared to 35.6 percent for the first quarter of 2012. The increase in expense was primarily due to an increase in income before income taxes.

Avista Utilities

Non-GAAP Financial Measures

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

2013 compared to 2012

Net income for Avista Utilities was $42.3 million for the first quarter of 2013, an increase from $39.5 million for the first quarter of 2012. Avista Utilities' income from operations was $82.8 million for the first quarter of 2013, an increase from $77.1

million for the first quarter of 2012. The increase in net income and income from operations was primarily due to the implementation of general rate increases in Washington, partially offset by expected increases in depreciation and amortization, and taxes other than income taxes.

The following table presents our operating revenues, resource costs and resulting gross margin for the three months ended March 31 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2013	2012	2013	2012	2013	2012	2013	2012
Operating revenues	$ 287,738	$ 256,056	$ 185,271	$ 177,500	$ (41,432)	$ (27,646)	$ 431,577	$ 405,910
Resource costs	145,063	117,932	125,999	120,726	(41,432)	(27,646)	229,630	211,012
Gross margin	$ 142,675	$ 138,124	$ 59,272	$ 56,774	$ —	$ —	$ 201,947	$ 194,898

Avista Utilities' operating revenues increased $25.7 million and resource costs increased $18.6 million, which resulted in an increase of $7.1 million in gross margin. The gross margin on electric sales increased $4.6 million and the gross margin on natural gas sales increased $2.5 million. The increase in both electric and natural gas gross margin was primarily due to the Washington general rate increases. For the first quarter of 2013, we recognized a pre-tax benefit of $3.1 million under the ERM in Washington compared to $4.2 million for the first quarter of 2012.

Intracompany revenues and resource costs represent purchases and sales of natural gas between our natural gas distribution operations and our electric generation operations (as fuel for our generation plants). These transactions are eliminated in the presentation of total results for Avista Utilities and in the condensed consolidated financial statements but are reflected in the presentation of the separate results for electric and natural gas below.

The following table presents our utility electric operating revenues and megawatt-hour (MWh) sales for the three months ended March 31 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2013	2012	2013	2012
Residential	$ 97,674	$ 98,768	1,109	1,120
Commercial	69,366	72,222	756	782
Industrial	29,567	28,466	531	497
Public street and highway lighting	1,814	1,784	6	6
Total retail	198,421	201,240	2,402	2,405
Wholesale	40,094	25,017	1,149	886
Sales of fuel	31,772	25,043	—	—
Other	17,451	4,756	—	—
Total	$ 287,738	$ 256,056	3,551	3,291

Retail electric revenues decreased $2.8 million due to a slight decrease in total MWhs sold (decreased revenues $0.2 million) and a decrease in revenue per MWh (decreased revenues $2.6 million). Compared to the first quarter of 2012, residential electric use per customer decreased 2 percent and commercial use per customer decreased 4 percent. Heating degree days at Spokane were close to historical average for the first quarter of 2013, and 1 percent above the first quarter of 2012. The decrease in revenue per MWh was primarily due to a change in revenue mix, with a greater percentage of retail revenue from industrial customers, as well as other rate changes that do not impact gross margin (including the ERM rebate), and was partially offset by the Washington general rate increase.

Wholesale electric revenues increased $15.1 million due to an increase in sales volumes (increased revenues $9.2 million) and an increase in sales prices (increased revenues $5.9 million).

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market rather than operate the generating units. The revenues from sales of fuel increased $6.7 million due to an increase in sales of natural gas fuel as part of thermal generation resource optimization activities, as well as an increase in natural gas prices. For the first quarter of 2013, $27.8 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For the first quarter of 2012, $16.8 million of these sales were made to our natural gas operations.

Other electric revenues increased $12.7 million primarily due to the receipt of $11.7 million of revenue from Bonneville for past use of our electric transmission system. The majority of this revenue was deferred as a regulatory liability (and included in electric resource costs). Approximately $7.6 million of this revenue relates to our Washington business and it will remain deferred pending regulatory approval of certain accounting and ratemaking treatment in Washington. The remainder of this revenue ($4.1 million) relates to our Idaho business and was addressed in the recently approved Idaho general rate case settlement. See further information above at "Bonneville Power Administration Reimbursement and Reardan Wind Generation Project."

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

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

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2013	2012	2013	2012
Residential	$ 79,954	$ 84,833	84,140	82,564
Commercial	39,383	42,625	48,454	48,296
Interruptible	745	750	1,580	1,385
Industrial	1,134	1,283	1,676	1,696
Total retail	121,216	129,491	135,850	133,941
Wholesale	59,698	44,340	163,391	157,936
Transportation	2,082	1,900	46,286	44,530
Other	2,275	1,769	207	181
Total	$ 185,271	$ 177,500	345,734	336,588

Retail natural gas revenues decreased $8.3 million primarily due to lower retail rates (decreased revenues $10.0 million), partially offset by a slight increase in volumes (increased revenues $1.7 million). Lower retail rates were due to PGAs, partially offset by the Washington general rate case. We sold more retail natural gas in the first quarter of 2013 as compared to the first quarter of 2012 primarily due to colder weather in January and February. Compared to the first quarter of 2012, residential natural gas use per customer increased 1 percent. Heating degree days at Spokane were close to historical average for the first quarter of 2013, and 1 percent above the first quarter of 2012. Heating degree days at Medford were 2 percent above historical average for the first quarter of 2013, and 2 percent below the first quarter of 2012.

Wholesale natural gas revenues increased $15.4 million due to an increase in prices (increased revenues $13.4 million) and an increase in volumes (increased revenues $2.0 million). We plan for sufficient natural gas capacity to serve our retail customers on a theoretical peak day. As such, on nonpeak days we generally have more pipeline and storage capacity than what is needed for retail loads. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that partially offsets net natural gas costs. In some situations, customer demand is below the amount hedged and we sell natural gas in excess of load requirements. In the first quarter of 2013, $13.6 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In the first quarter of 2012, $10.8 million of these sales were made to our electric generation operations. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.

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

	Electric Customers		Natural Gas Customers	
	2013	2012	2013	2012
Residential	320,680	318,586	289,108	286,862
Commercial	40,096	39,803	34,074	33,821
Interruptible	—	—	39	37
Industrial	1,383	1,388	264	259
Public street and highway lighting	524	457	—	—
Total retail customers	362,683	360,234	323,485	320,979

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

	2013	2012
Electric resource costs:		
Power purchased	$ 58,963	$ 51,292
Power cost amortizations, net	(521)	1,138
Fuel for generation	36,174	27,977
Other fuel costs	30,697	28,254
Other regulatory amortizations, net	14,894	4,541
Other electric resource costs	4,856	4,730
Total electric resource costs	145,063	117,932
Natural gas resource costs:		
Natural gas purchased	119,903	113,955
Natural gas cost amortizations, net	3,120	2,960
Other regulatory amortizations, net	2,976	3,811
Total natural gas resource costs	125,999	120,726
Intracompany resource costs	(41,432)	(27,646)
Total resource costs	$ 229,630	$ 211,012

Power purchased increased $7.7 million due to an increase in the volume of power purchases (increased costs $6.8 million) and an increase in wholesale prices (increased costs $0.9 million).

Net amortization of deferred power costs decreased electric resource costs by $0.5 million for the first quarter of 2013 compared to an increase of $1.1 million to electric resource costs for the first quarter of 2012. During the first quarter of 2013, we refunded to customers $0.8 million of previously deferred power costs in Idaho through the PCA rebate. As part of the Washington rate case settlement implemented on January 1, 2013, we refunded to customers $0.9 million through an ERM rebate. During the first quarter of 2013, actual power supply costs were below the amount included in base retail rates and we deferred $0.2 million in Washington and $1.0 million in Idaho for potential future rebate to customers.

Fuel for generation increased $8.2 million due to an increase in thermal generation and an increase in natural gas fuel prices.

Other fuel costs increased $2.4 million. This represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation, as part of the resource optimization process. When the fuel is sold, the revenue generated from selling the fuel is included in the sales of fuel revenue line item above.

Electric other regulatory amortizations increased $10.4 million primarily due to the regulatory deferral of $7.6 million for the Washington portion of the Bonneville revenue for past use of our transmission system pending approval from the UTC. We also deferred $3.9 million for the Idaho portion of the Bonneville revenue for future refund to our Idaho customers.

The expense for natural gas purchased increased $5.9 million due to an increase in the price of natural gas (increased costs $3.0 million) and an increase in total therms purchased (increased costs $2.9 million). Total therms purchased increased due to an increase in wholesale sales which are used to balance loads and resources as part of the natural gas procurement and resource optimization process, as well as an increase in retail sales. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs.

Ecova

2013 compared to 2012

Ecova's net income attributable to Avista Corp. shareholders was $1.2 million for the three months ended March 31, 2013 compared to a net loss of $0.8 million for the three months ended March 31, 2012. Operating revenues increased $5.4 million and total operating expenses increased $0.9 million. The increase in operating revenues was primarily the result of increased revenues associated with new services, which added $3.0 million to revenue. In addition, there was an increase in volumes associated with expense and data management services and energy management services, which added $2.1 million and $0.3 million to revenue, respectively.

The increase in total operating expenses primarily reflects an increase in depreciation and amortization of $0.7 million due to intangibles recorded in connection with the LPB acquisition and an increase in other operating expenses of $0.2 million.

Ecova's other operating expenses associated with cost of services increased $2.2 million for the first quarter of 2013 and totaled $22.3 million due to higher revenue volumes in expense and data management services and new services. Ecova's other operating expenses associated with selling, general and administrative expenses decreased by $2.0 million in the first quarter of 2013 and totaled $13.7 million. This decrease was primarily the result of a decrease in acquisition and integration costs of $1.5 million, which were incurred during the first quarter of 2012 and did not reoccur during 2013.

As of March 31, 2013, Ecova had over 700 expense management customers representing over 700,000 billed sites in North America. In the first quarter of 2013, Ecova managed bills totaling $5.1 billion, an increase of $0.7 billion as compared to the first quarter of 2012. The increase in bills managed was due to an increase in the number of billed sites, partially offset by a decrease in the average value of each bill.

Other Businesses

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

	March 31, 2013	December 31, 2012
Spokane Energy	$ 51,478	$ 54,235
Avista Energy	12,558	12,549
METALfx	11,131	11,273
Steam Plant and Courtyard Office Center	7,064	7,122
Other	10,184	10,459
Total	$ 92,415	$ 95,638

2013 compared to 2012

The net loss from these operations was $1.1 million for the first quarter of 2013 compared to a net loss of $0.3 million for the first quarter of 2012. The losses for the first quarter of 2013 were primarily the result of an impairment loss of $0.5 million pre-tax ($0.3 million after-tax) associated with our investment in an energy storage company, increased costs associated with exploring strategic opportunities of $0.4 million, and litigation costs related to the previous operations of Avista Energy of $0.4 million. These losses were partially offset by METALfx, which had net income of $0.2 million for the first quarter of 2013.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires us to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on our consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein. Our critical accounting policies that require the use of estimates and assumptions were discussed in detail in the 2012 Form 10-K and have not changed materially from that discussion.

Liquidity and Capital Resources

Review of Cash Flow Statement

Overall During the first quarter of 2013, positive cash flows from operating activities of $105.4 million were used to fund the majority of our cash requirements. These cash requirements included utility capital expenditures of $70.6 million and dividends of $18.4 million.

Operating Activities Net cash provided by operating activities was $105.4 million for the first quarter of 2013 compared to $121.3 million for the first quarter of 2012. Net cash provided by working capital components was $25.2 million for the first quarter of 2013, compared to net cash provided of $49.2 million for the first quarter of 2012. The net cash provided during the first quarter of 2013 primarily reflects positive cash flows from other current liabilities (primarily related to fluctuations in accrued taxes, accrued interest, and other miscellaneous accrued liabilities) and positive cash flows from a seasonal decrease in natural gas stored. These positive cash flows were partially offset by net cash outflows related to accounts payable and other current assets.

The net cash provided during the first quarter of 2012 primarily reflects positive cash flows from other current assets (primarily related to a decrease in income taxes receivable), net cash inflows related to accounts receivable and a seasonal decrease in natural gas stored. These positive cash flows were partially offset by net cash outflows related to accounts payable.

Net amortization of deferred power and natural gas costs was $2.5 million for the first quarter of 2013 compared to $4.1 million for the first quarter of 2012. The provision for deferred income taxes was $1.1 million for the first quarter of 2013 compared to a benefit of $0.3 million for the first quarter of 2012. Contributions to our defined benefit pension plan were $14.7 million for both the first quarter of 2013 and the first quarter of 2012. Cash paid for interest was $7.4 million for the first quarter of 2013, compared to $6.7 million for the first quarter of 2012.

Investing Activities Net cash used in investing activities was $86.7 million for the first quarter of 2013, a decrease compared to $154.3 million for the first quarter of 2012. Utility property capital expenditures increased by $12.9 million for the first quarter of 2013 as compared to the first quarter of 2012. In both the first quarter of 2013 and the first quarter of 2012, a significant portion of Ecova's funds held for clients were held as securities available for sale (with purchases of $25.0 million and sales and maturities of $7.0 million for the first quarter of 2013 and purchases of $36.5 million sales and maturities of $27.0 million for the first quarter of 2012. The $50.3 million of net cash paid by subsidiaries for acquisitions in the first quarter of 2012 primarily represents Ecova’s acquisition of LPB.

Financing Activities Net cash used in financing activities was $5.0 million for the first quarter of 2013 compared to net cash provided of $31.1 million for the first quarter of 2012. During the first quarter of 2013, short-term borrowings on Avista Corp.’s committed line of credit increased $0.5 million. Net borrowings on Ecova's committed line of credit did not change; however, there were borrowings of $3.0 million and repayments of $3.0 million during the period. Cash dividends paid increased to $18.4 million (or $0.305 per share) for the first quarter of 2013 from $17.1 million (or $0.29 per share) for the first quarter of 2012. We issued $1.1 million of common stock during the first quarter of 2013. Customer fund obligations at Ecova increased $15.4 million.

During the first quarter of 2012, short-term borrowings on Avista Corp.'s committed line of credit decreased $24.0 million. Borrowings on Ecova's committed line of credit increased $25.0 million and these proceeds were used to fund a portion of the acquisition of LPB. We issued $1.4 million of common stock during the first quarter of 2012. Customer fund obligations at Ecova increased $45.2 million.

Overall Liquidity

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

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

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

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

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

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

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

As of March 31, 2013, we had $334.9 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 March 31, 2013, we had cash deposited as collateral of $21.9 million and letters of credit of $10.1 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 March 31, 2013, we would potentially be required to post additional collateral of up to $8.8 million. This amount is different from the amount disclosed in “Note 5 of the Notes to Condensed Consolidated Financial Statements” because, while this analysis includes contracts that are not considered derivatives in addition to the contracts considered in Note 5, this analysis takes into account contractual threshold limits that are not considered in Note 5. Without contractual threshold limits, we would potentially be required to post additional collateral of $23.9 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 March 31, 2013, 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 March 31, 2013, we would not be required to post additional collateral.

Dodd-Frank Wall Street Reform and Consumer Protection Act

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

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

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

Capital Resources

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings, and excluding noncontrolling interests, consisted of the following as of March 31, 2013 and December 31, 2012 (dollars in thousands):

	March 31, 2013		December 31, 2012	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 50,354	1.9%	$ 50,372	1.9%
Current portion of nonrecourse long-term debt (Spokane Energy)	15,309	0.6%	14,965	0.6%
Short-term borrowings	52,500	1.9%	52,000	1.9%
Long-term borrowings under committed line of credit	54,000	2.0%	54,000	2.0%
Long-term debt to affiliated trusts	51,547	1.9%	51,547	1.9%
Nonrecourse long-term debt (Spokane Energy)	13,872	0.5%	17,838	0.7%
Long-term debt	1,178,766	43.7%	1,178,367	44.0%
Total debt	1,416,348	52.5%	1,419,089	53.0%
Total Avista Corporation stockholders’ equity	1,283,976	47.5%	1,259,477	47.0%
Total	$ 2,700,324	100.0%	$ 2,678,566	100.0%

We need to finance capital expenditures and acquire additional funds for operations from time to time. The cash requirements needed to service our indebtedness, both short-term and long-term, reduce the amount of cash flow available to fund capital expenditures, purchased power, fuel and natural gas costs, dividends and other requirements. Our stockholders' equity increased $24.5 million during 2013 primarily due to net income partially offset by dividends.

We generally fund capital expenditures with a combination of internally generated cash and external financing. The level of cash generated internally and the amount that is available for capital expenditures fluctuates depending on a variety of factors. Cash provided by our utility operating activities, as well as issuances of long-term debt and common stock, are expected to be the primary source of funds for operating needs, dividends and capital expenditures for 2013. Borrowings under our $400.0 million committed line of credit will supplement these funds to the extent necessary.

In August 2012, we entered into two sales agency agreements under which we may sell up to 2.7 million shares of our common stock from time to time. As of March 31, 2013, we had 1.8 million shares available to be issued under these agreements.

We are planning to issue up to $50.0 million of common stock in 2013 in order to maintain our capital structure at an appropriate level for our business, with the majority of the issuances in the second half of the year. In the first quarter of 2013, we issued $1.1 million (net of issuance costs) of common stock. The additional shares were issued under the dividend reinvestment and direct stock purchase plan and employee plans.

There are $50.0 million in First Mortgage Bonds maturing in 2013 and we expect to issue up to $100.0 million of long-term debt during the second half of 2013.

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. Borrowings under this line of credit agreement are classified as short-term on the Condensed Consolidated Balance Sheets.

This facility contains customary covenants and default provisions, including a covenant which does not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 65 percent at any time. As of March 31, 2013, we were in compliance with this covenant with a ratio of 52.5 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 three months ended March 31 (dollars in thousands):

	2013	2012
Borrowings outstanding at end of period	$ 52,500	$ 37,000
Letters of credit outstanding at end of period	$ 12,608	$ 20,090
Maximum borrowings outstanding during the period	$ 52,500	$ 63,500
Average borrowings outstanding during the period	$ 16,619	$ 18,341
Average interest rate on borrowings during the period	1.09%	1.24%
Average interest rate on borrowings at end of period	1.17%	3.25%

As part of their cash management practices and operations, Ecova and Avista Corp. entered into an arrangement 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 $32.1 million and the maximum balance was $50.0 million during the three months ended March 31, 2013 and the three months ended March 31, 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 March 31, 2013, Avista Corp. and its subsidiaries were in compliance with all of the covenants of their financing agreements, and none of Avista Corp.'s subsidiaries constituted a "significant subsidiary" as defined in Avista Corp.'s committed line of credit.

Ecova also has a committed line of credit agreement with various financial institutions for $125.0 million with an expiration date of July 2017. This credit agreement is used primarily to fund acquisitions at Ecova and supplement cash flow for Ecova's operations when necessary and is generally not available for capital acquisitions. There were $54.0 million of borrowings outstanding under Ecova's credit agreement as of March 31, 2013 classified as long-term. See the "Ecova Credit Agreement" section below for further discussion regarding this agreement.

Avista Utilities Capital Expenditures

We expect utility capital expenditures to be about $260 million for each of 2013, 2014 and 2015. These estimates of capital expenditures are subject to continuing review and adjustment. Actual capital expenditures may vary from our estimates due to factors such as changes in business conditions, construction schedules and environmental requirements.

Included in our estimates of capital expenditures is the replacement of our customer information and work management systems, which is expected to be completed by the end of 2014. We expect to spend a total of approximately $80 million (including internal labor) over the term of the project. Major signed contracts for third parties total approximately $27 million as of March 31, 2013.

Ecova Credit Agreement

Ecova has a $125.0 million committed line of credit agreement with various financial institutions with an expiration date of July 2017. The credit agreement is secured by all of Ecova's assets excluding investments and funds held for clients. There were $54.0 million of borrowings outstanding under Ecova's credit agreement as of March 31, 2013 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.

The committed line of credit agreement contains customary covenants and default provisions, including a covenant which requires that Ecova's "Consolidated Total Funded Debt to EBITDA Ratio" (as defined in the credit agreement) must be 2.50 to 1.00 or less, with provisions in the credit agreement allowing for a temporary increase of this ratio if a qualified acquisition is consummated by Ecova. In addition, Ecova's "Consolidated Fixed Charge Coverage Ratio" (as defined in the credit agreement) must be greater than 1.50 to 1.00 as of the last day of any fiscal quarter. As of March 31, 2013, Ecova was in compliance with these covenants and based on the Consolidated Total Funded Debt to EBITDA Ratio, Ecova could borrow an additional $11.6 million and still be compliant with the covenants. The covenant restrictions are calculated on a rolling twelve month basis, so this additional borrowing capacity could increase or decrease or Ecova could be required to pay down the outstanding debt as future results change.

Ecova Redeemable Stock

Ecova's amended employee stock incentive plan provides an annual window at which time holders of common stock can put their shares back to Ecova, providing the shares are held for a minimum of six months. Stock is reacquired at fair market value, less the strike price, at the date of reacquisition. The value of the redeemable noncontrolling interests in Ecova associated with redeemable stock options and other outstanding redeemable stock was $8.0 million at March 31, 2013, an increase from $4.9 million at December 31, 2012. Options are valued at their maximum redemption amount which is equal to their intrinsic value (fair value less exercise price). During the first quarter of 2013, the estimated fair value of Ecova common stock increased such that it is higher compared to the exercise price of the options which increased the overall value of the redeemable noncontrolling interests to their current value. In 2009, the Ecova employee stock incentive plan was amended such that, on a prospective basis, not all options granted under the plan have the put right.

Off-Balance Sheet Arrangements

As of March 31, 2013, we had $12.6 million in letters of credit outstanding under our $400.0 million committed line of credit, compared to $35.9 million as of December 31, 2012.

Pension Plan

As of March 31, 2013, our pension plan had assets with a fair value that was less than the benefit obligation under the plan. In 2012, the Moving Ahead for Progress in the 21st Century (MAP-21) federal legislation was approved that changed how the required discount rate was calculated for funding purposes, impacting the minimum required contributions as determined by ERISA federal regulations and the Internal Revenue Code. The change in law required the discount rate (for the target liability) to be calculated over a 25-year average versus the previously required 2-year average. Although the legislation was not passed until late 2012, the change in discount rate was retroactively effective to January 1, 2012. This significantly increased the discount rate resulting in a lower target liability. The funded status, as determined by ERISA federal regulations and the Internal Revenue Code, for our plan increased from approximately 80 percent to 102 percent without any other changes as of January 1, 2012.

We expect to contribute a total of $148.5 million to the pension plan in the period 2013 through 2016, with contributions of $44 million per year for the period 2013 to 2015 and a contribution of $16.5 million in 2016. Our contribution is expected to decrease in 2016 as we move toward fully funded status. The final determination of pension plan contributions for future periods is subject to multiple variables, most of which are beyond our control, including further changes to the fair value of pension plan assets, changes in actuarial assumptions (in particular the discount rate used in determining the benefit obligation), or changes in federal legislation. We may change our pension plan contributions in the future depending on changes to any of the above variables.

Credit Ratings

Our access to capital markets and our cost of capital are directly affected by our credit ratings. In addition, many of our contracts for the purchase and sale of energy commodities contain terms dependent upon our credit ratings. See “Collateral Requirements” and “Note 5 of the Notes to Condensed Consolidated Financial Statements.” The following table summarizes our credit ratings as of May 3, 2013:

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

(1) Standard & Poor’s lowest “investment grade” credit rating is BBB-.
(2) Moody’s lowest “investment grade” credit rating is Baa3.

A security rating is not a recommendation to buy, sell or hold securities. Each security rating is subject to revision or withdrawal at any time by the assigning rating organization. Each security rating agency has its own methodology for assigning ratings, and, accordingly, each rating should be considered in the context of the applicable methodology, independent of all other ratings. The rating agencies provide ratings at the request of Avista Corp. and charge fees for their services.

Dividends

The Board of Directors considers the level of dividends on our common stock on a regular basis, taking into account numerous factors including, without limitation:

- our results of operations, cash flows and financial condition,
- the success of our business strategies, and
- general economic and competitive conditions.

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

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

On February 8, 2013, Avista Corp.’s Board of Directors declared a quarterly dividend of $0.305 per share on the Company’s common stock. This was an increase of $0.015 per share, or 5 percent from the previous quarterly dividend of $0.29 per share.

Contractual Obligations

Our future contractual obligations have not changed materially from the amounts disclosed in the 2012 Form 10-K.

Economic Conditions

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

We track multiple economic indicators affecting three distinct metropolitan areas in our service area: Spokane, Washington, Coeur d'Alene, Idaho, and Medford, Oregon. Several key indicators are employment change, unemployment rates and foreclosure rates. On a year-over-year basis, March 2013 showed mixed job growth, and lower unemployment rates in all three metropolitan areas. Foreclosure rates were below the U.S rate in the Coeur d'Alene and Medford areas. However, the unemployment rates are still above the national average and two key leading indicators, regional initial unemployment claims and residential building permits, continue to signal modest growth over the next 12 months. Therefore, in 2013, we continue to expect economic growth in our service area to be somewhat slower than the U.S. as a whole.

Seasonally adjusted nonfarm employment in our eastern Washington, northern Idaho, and southwestern Oregon metropolitan service areas exhibited mixed growth between March 2012 and March 2013. In Spokane, Washington employment growth was

1.4 percent with gains in manufacturing; information; leisure and hospitality; and business and professional services. Employment decreased by 1.7% percent in Coeur d'Alene, Idaho, reflecting weakness in mining and logging; construction; and professional and business services. In Medford, Oregon, employment growth was 0.5 percent, with gains in construction; leisure and hospitality; and business and professional services. U.S. nonfarm sector jobs grew by 0.8 percent in the same twelve-month period.

Unemployment rates (not seasonally adjusted) went down in March 2013 from the year earlier in Spokane, Coeur d'Alene, and Medford. In Spokane the rate was 9.7 percent in March 2012 and declined to 9.1 percent in March 2013; in Coeur d'Alene the rate went from 10.3 percent to 8.6 percent; and in Medford the rate declined from 12.2 percent to 10.7 percent. The U.S. rate declined from 8.4 percent to 7.6 percent in the same period.

The housing market in our Idaho and Oregon service areas continue to experience foreclosure rates lower than the national average. The March 2013 national rate was 0.12 percent, compared to 0.06 percent in Kootenai County (Coeur d'Alene), Idaho; and 0.01 percent in Jackson County (Medford), Oregon. The rate for Spokane County, Washington was above the national rate at 0.22 percent.

Environmental Issues and 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 established 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 Steam Generation Facility (Colstrip) (expires in 2017), Coyote Springs 2 (renewal expected in 2013), the Kettle Falls Generation Station (GS) (renewal expected in 2013), and the Rathdrum Combustion Turbine (CT) (expires in 2016). Boulder Park GS, Northeast CT, and other activities only require minor source operating or registration permits based on their limited operation and emissions. The Title V operating permits are renewed every five years and updated to include all newly applicable CAA requirements. We actively monitor legislative, regulatory and program developments within the CAA that may impact our facilities.

On March 6, 2013, the Sierra Club and Montana Environmental Information Center (collectively "Plaintiffs"), filed a Complaint (Complaint) in the United States District Court for the District of Montana, Billings Division, against the owners of the Colstrip Generating Project (Colstrip). The Complaint alleges certain violations of the Clean Air Act, including requirements related to New Source Review, Title V and opacity limits. Avista Corp. is evaluating the allegations set forth in the Complaint and cannot at this time predict the outcome of the matter. See “Sierra Club and Montana Environmental Information Center Litigation” in “Note 11 of the Notes to Condensed Consolidated Financial Statements” for further information on this matter.

Hazardous Air Pollutants (HAPs)

The EPA regulates hazardous air pollutants from a published list of industrial sources referred to as "source categories" which must meet control technology requirements if they emit one or more of the pollutants in significant quantities. In 2012, the EPA finalized the Mercury Air Toxic Standards (MATS) for the coal and oil-fired source category. For Colstrip Units 3 & 4, the only units in which we are a minority owner, the existing emission control systems should be sufficient to meet mercury limits. For the remaining portion of the rule that utilizes Particulate Matter as a surrogate for air toxics (including metals and acid gases), the Colstrip owners continue to review stack testing data to determine whether new emission control systems will be needed for Units 3 & 4 MATS compliance We continue to monitor these results, but are currently unable to determine if there will be material impacts to Colstrip Units 3 & 4.

Regional Haze Program

The EPA set a national goal of eliminating man-made visibility degradation in Class I areas by the year 2064. States are expected to take actions to make "reasonable progress" through 10-year plans, including application of Best Available Retrofit Technology (BART) requirements. BART is a retrofit program applied to large emission sources, including electric generating units built between 1962 and 1977. In the case where a State opts out of implementing the Regional Haze program, the EPA may act directly. On September 18, 2012, the EPA finalized the Regional Haze federal implementation plan (FIP) for Montana. The FIP includes both emission limitations and pollution controls for Colstrip Units 1 & 2. Colstrip Units 3 & 4, the only units of which we are a minority owner, 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. In November 2012, the National Parks Conservation Association, MEIC and Sierra Club filed a petition for review of EPA's Montana FIP in the U.S. Court of Appeals for the Ninth Circuit. We continue to monitor, but are unable to predict the outcome of this matter.

Climate Change

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.

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

- facilitates internal and external communications regarding climate change issues,
- analyzes policy impacts, anticipates opportunities and evaluates strategies for Avista Corp., and
- develops recommendations on climate related policy positions and action plans.

Federal Legislation

The U.S. Congress has considered many proposals to reduce greenhouse gas emissions and mandate renewable or clean energy. The financial and operational impacts of climate or energy legislation, if enacted, would depend on a variety of factors, including the specific provisions and timing of any legislation that might ultimately be adopted. Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions, renewable or clean energy standards, and/or energy efficiency standards are expected to continue to be considered by the U.S. Congress.

Federal Regulatory Actions

The U.S. Supreme Court ruled in 2007 that the EPA had authority under the CAA to regulate greenhouse gas emissions from new motor vehicles; subsequently, the EPA issued regulations on tailpipe emissions of greenhouse gases (GHG). When these regulations became effective, GHG became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. In 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. The EPA proposed a rule in early 2012 setting performance standards for GHG emissions from new and modified fossil fuel-fired electric generating units and announced plans to issue GHG emissions guidelines for existing sources. The rule for new sources has not been finalized, and no rule for existing sources has yet been proposed.

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. Our thermal generation facilities may be impacted by the promulgated PSD permitting rules in the future. These rules can impact the time to obtain permits for new generation and major modifications to existing generating units and the final permit limitations. The promulgated and proposed GHG rulemakings mentioned above also have been legally challenged in multiple venues, so we cannot fully anticipate the outcome or extent our facilities may be impacted by these regulations at this time.

EPA Mandatory Reporting Rule (MRR)

Any facility emitting over 25,000 metric tons of GHGs per year must report its emissions. We currently report under this requirement for Colstrip, Coyote Springs 2, and Rathdrum CT. MRR also requires GHG reporting for natural gas distribution system throughput, fugitive emissions from electric power transmission and distribution systems, fugitive emissions from natural gas distribution systems, and from natural gas storage facilities. We reported the applicable GHG emissions in 2012, and are on target for future reporting requirements.

State Legislation and State Regulatory Activities

The states of Washington and Oregon have adopted non-binding targets to reduce GHG emissions. Both states enacted their targets with an expectation of reaching the targets through a combination of renewable energy standards, and assorted "complementary policies," but no specific reductions are mandated.

Washington State's Department of Ecology has adopted regulations to update its State Implementation Plan relative to 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, and cannot predict any material impact at this time.

Washington and Oregon apply a GHG emissions performance standard (EPS) to electric generation facilities used to serve retail loads in their jurisdictions. The EPS 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 Washington State Department of Commerce (Commerce) initiated a process to adopt a lower emissions performance standard in 2012; any new standard will be applicable until at least 2017. Commerce published a supplemental notice of proposed rulemaking on January 16, 2013 with a new EPS of 970 pounds of GHG per MWh. We will continue to monitor this rulemaking, and cannot predict any material impact at this time.

Initiative Measure 937 (I-937), the Energy Independence Act, became law in Washington's 2006 General Election. I-937 requires electric utilities with over 25,000 customers to acquire qualified renewable energy resources and/or renewable energy credits equal to 15 percent of the utility's total retail load in 2020. I-937 also requires these utilities to meet biennial energy conservation targets beginning in 2012. Furthermore, by January 1, 2012, electric utilities subject to I-937's mandates must acquire enough qualified renewable energy and/or renewable energy credits to meet three percent of their retail load. This renewable energy standard increases to nine percent in 2016. Failure to comply with renewable energy and efficiency standards could result in penalties of $50 per MWh or greater assessed against a utility for each MWh it is deficient in meeting a standard. We have met, and will continue to meet, the requirements of I-937 through a variety of renewable energy generating means, including, but not limited to, some combination of hydro upgrades, wind and biomass. In 2012, I-937 was amended in such a way that our Kettle Falls Generating Station and certain other biomass energy facilities which commenced operation before March 31, 1999, are considered resources that may be used to meet the renewable energy standards beginning in 2016.

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 RCRA, such action could significantly impact future operations of Colstrip. Congress has also considered proposed legislation regarding CCB management. We cannot predict the impact of future CCB regulation. If we were to incur incremental costs as a result of new CCB regulations, we would seek recovery in customer rates. On April 19, 2013, EPA signed proposed revisions to the Steam Electric Guidelines (40 CFR Part 423), which, once developed and if adopted, could impact wastewater management at Colstrip. We are reviewing the proposed revisions and cannot at this time predict whether they will have any material impact.

Threatened and Endangered Species and Wildlife

A number of species of fish in the Northwest 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 are implementing fish protection measures at our hydroelectric project on the Clark Fork River under a 45-year FERC operating license for Cabinet Gorge and Noxon Rapids (issued 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 resolved through the ongoing collaborative effort of our Clark Fork and Spokane River FERC licenses. See “Spokane River Licensing” and “Fish Passage at Cabinet Gorge and Noxon Rapids” in “Note 11 of the Notes to Condensed Consolidated Financial Statements” for further information.

Various statutory authorities, including the Migratory Bird Treaty Act, have established penalties for the unauthorized take of migratory birds. Because we operate facilities that can pose risks to a variety of such birds, we have developed and follow an avian protection plan.

Other

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our primary market risk exposures are:

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

Commodity Price Risk

Our qualitative commodity price risk disclosures have not materially changed during the three months ended March 31, 2013 . Please refer to the 2012 Form 10-K. The following table presents energy commodity derivative fair values as a net asset or (liability) as of March 31, 2013 that are expected to settle in each respective year (dollars in thousands):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical	Financial	Physical	Financial
2013	$ 73	$ (5,806)	$ (1,962)	$ (2,687)	$ (524)	$ 3,317	$ (561)	$ 2,487
2014	(2,667)	(426)	(5,459)	(7,676)	165	3,740	(1,364)	1,554
2015	(3,255)	(949)	(1,845)	(4,917)	(72)	1,368	—	1,383
2016	(2,903)	—	(444)	(782)	(182)	164	—	248
2017	(2,551)	—	—	—	(276)	—	—	—
Thereafter	(3,343)	—	—	—	(623)	—	—	—

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

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

The above electric and natural gas derivative contracts will be included in either power supply costs or natural gas supply costs during the period they settle and will be included in the various recovery mechanisms (ERM, PCA, and PGAs), or in the general rate case process, and are expected to eventually be collected through retail rates from customers.

Credit Risk

Our credit risk has not materially changed during the three months ended March 31, 2013. See the 2012 Form 10-K.

Risk Management for Energy Resources

We use a variety of techniques to manage risks for energy resources and wholesale energy market activities. We have an energy resources risk policy, which includes our wholesale energy markets credit policy and control procedures to manage these risks, both qualitative and quantitative. The 2012 Form 10-K contains a discussion of risk management policies and procedures.

Interest Rate Risk

Our qualitative interest rate risk disclosures have not materially changed during the three months ended March 31, 2013. See the 2012 Form 10-K.

As of March 31, 2013, 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 March 31, 2013, we had a current derivative asset of $2.3 million and a long-term derivative asset of $10.6 million, with an offsetting regulatory liability on the Condensed Consolidated Balance Sheets in accordance with regulatory accounting practices.

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

In anticipation of issuing long-term debt in 2015 and 2016, we entered into two interest rate swap agreements in April 2013, each with a notional amount $20.0 million (total notional amount of $40.0 million) with mandatory cash settlement dates of October 2015 and October 2016.

Foreign Currency Risk

Our qualitative foreign currency risk disclosures have not materially changed during the three months ended March 31, 2013. See the 2012 Form 10-K. As of March 31, 2013, we had a current derivative asset for foreign currency hedges of less than $0.1 million included in other current assets on the Condensed Consolidated Balance Sheet. As of March 31, 2013, we had entered into 22 Canadian currency forward contracts with a notional amount of $4.4 million ($4.5 million Canadian). As of December 31, 2012, we had entered into 20 Canadian currency forward contracts with a notional amount of $12.6 million ($12.5 million Canadian) with current derivative liability of less than $0.1 million.

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

Item 4. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended) to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company’s management, including its principal executive and principal financial officers as appropriate to allow timely decisions regarding required disclosure. Under the supervision and with the participation of the Company’s management, including the Company’s principal executive officer and principal financial officer, the Company evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives. Based upon the Company’s evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures are effective at a reasonable assurance level as of March 31, 2013.

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

PART II. Other Information

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Please refer to the 2012 Form 10-K for disclosure of risk factors that could have a significant impact on our results of operations, financial condition or cash flows and could cause actual results or outcomes to differ materially from those discussed in our reports filed with the Securities and Exchange Commission (including this Quarterly Report on Form 10-Q), and elsewhere. These risk factors have not materially changed from the disclosures provided in the 2012 Form 10-K. In addition to these risk factors, see also "Forward-Looking Statements" for additional factors which could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

Item 4. Mine Safety Disclosures

Not applicable.

Item 6. Exhibits

12	Computation of ratio of earnings to fixed charges*
15	Letter Re: Unaudited Interim Financial Information*
31.1	Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002)*
31.2	Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002)*
32	Certification of Corporate Officers (Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)**
101	The following financial information from the Quarterly Report on Form 10−Q for the period ended March 31, 2013, formatted in XBRL (Extensible Business Reporting Language) and filed electronically herewith: (i) the Condensed Consolidated Statements of Income; (ii) Condensed Consolidated Statements of Comprehensive Income; (iii) the Condensed Consolidated Balance Sheets; (iv) the Condensed Consolidated Statements of Cash Flows; (v) the Condensed Consolidated Statements of Equity and Redeemable Noncontrolling Interests; and (vi) the Notes to Condensed Consolidated Financial Statements.*

* Filed herewith.

** Furnished herewith.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

AVISTA CORPORATION
(Registrant)

Date: May 3, 2013

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

Exhibit 12

AVISTA CORPORATION

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

	Three months ended March 31, 2013	Years Ended December 31 2012	2011	2010	2009	2008
Fixed charges, as defined:						
Interest charges	$ 18,863	$ 73,633	$ 69,591	$ 72,010	$ 61,361	$ 74,914
Amortization of debt expense and premium - net	947	3,803	4,617	4,414	5,673	4,673
Interest portion of rentals	613	2,717	2,154	2,027	1,874	1,601
Total fixed charges	$ 20,423	$ 80,153	$ 76,362	$ 78,451	$ 68,908	$ 81,188
Earnings, as defined:						
Pre-tax income from continuing operations	$ 68,337	$ 120,061	$ 160,171	$ 146,105	$ 134,971	$ 120,382
Add (deduct):						
Capitalized interest	(940)	(2,401)	(2,942)	(298)	(545)	(4,612)
Total fixed charges above	20,423	80,153	76,362	78,451	68,908	81,188
Total earnings	$ 87,820	$ 197,813	$ 233,591	$ 224,258	$ 203,334	$ 196,958
Ratio of earnings to fixed charges	4.30	2.47	3.06	2.86	2.95	2.43

Exhibit 15

May 3, 2013

Avista Corporation
Spokane, Washington

We have reviewed, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the unaudited interim financial information of Avista Corporation and subsidiaries for the periods ended March 31, 2013 and 2012, as indicated in our report dated May 3, 2013; because we did not perform an audit, we expressed no opinion on that information.

We are aware that our report referred to above, which is included in your Quarterly Report on Form 10-Q for the quarter ended March 31, 2013, is incorporated by reference in Registration Statement Nos. 2-81697, 2-94816, 033-54791, 333-03601, 333-22373, 333-33790, 333-47290, 333-126577, and 333-179042 on Form S-8; and in Registration Statement Nos. 333 -187306 and 333-177981 on Form S-3.

We are also aware that the aforementioned report, pursuant to Rule 436(c) under the Securities Act of 1933, is not considered a part of the Registration Statement prepared or certified by an accountant or a report prepared or certified by an accountant within the meaning of Sections 7 and 11 of that Act.

/s/ Deloitte & Touche LLP

Seattle, Washington
May 3, 2013

Exhibit 31.1

CERTIFICATION

I, Scott L. Morris, certify that:

1. I have reviewed this report on Form 10-Q of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2013

/s/ Scott L. Morris

Scott L. Morris
Chairman of the Board, President
and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Mark T. Thies, certify that:

1. I have reviewed this report on Form 10-Q of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2013

/s/ Mark T. Thies

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

Exhibit 32

AVISTA CORPORATION

CERTIFICATION OF CORPORATE OFFICERS

(Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the

Sarbanes-Oxley Act of 2002)

Each of the undersigned, Scott L. Morris, Chairman of the Board, President and Chief Executive Officer of Avista Corporation (the “Company”), and Mark T. Thies, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2013 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: May 3, 2013

/s/ Scott L. Morris

Scott L. Morris
Chairman of the Board, President
and Chief Executive Officer

/s/ Mark T. Thies

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