AVISTA CORP
Form 10-Q
November 04, 2011

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2011

OR

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

For the transition period from to

Commission file number 1-3701

AVISTA CORPORATION

(Exact name of registrant as specified in its charter)

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

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

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

None

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

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

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

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

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

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

As of October 31, 2011, 58,215,534 shares of Registrant s Common Stock, no par value (the only class of common stock), were outstanding.

AVISTA CORPORATION

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FORWARD-LOOKING STATEMENTS

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

financial performance,

cash flows,

capital expenditures,

dividends,

capital structure,

other financial items,

strategic goals and objectives, and

plans for operations.

These statements have underlying assumptions (many of which are based, in turn, upon further assumptions). Such statements are made both in our reports filed under the Securities Exchange Act of 1934, as amended (including this Quarterly Report on Form 10-Q), and elsewhere. Forward-looking statements are all statements except those of historical fact including, without limitation, those that are identified by the use of words that include will, may, could, should, intends, plans, seeks, anticipates, estimates, expects, forecasts, projects, p 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 and precipitation levels) and their effects on energy demand and electric generation, including the effect of precipitation and temperatures on the availability of hydroelectric resources, the effect of temperatures on customer demand, and similar impacts on supply and demand in the wholesale energy markets;

- the effect of state and federal regulatory decisions on our ability to recover costs and earn a reasonable return including, but not limited to, the disallowance of costs and investments, and delay in the recovery of capital investments and operating costs;

- changes in wholesale energy prices that can affect, among other things, the cash requirements to purchase electricity and natural gas, the value received for sales in the wholesale energy market, the necessity to request changes in rates that are subject to regulatory approval, collateral required of us by counterparties on wholesale energy transactions and credit risk to us from such transactions, and the market value of derivative assets and liabilities;

- global financial and economic conditions (including the impact on capital markets) and their effect on our ability to obtain funding at a reasonable cost;

- our ability to obtain financing through the issuance of debt and/or equity securities, which can be affected by various factors including our credit ratings, interest rates and other capital market conditions;

- economic conditions in our service areas, including the effect on the demand for, and customers payment for, our utility services;

- the potential effects of legislation or administrative rulemaking, including the possible adoption of national or state laws requiring our resources to meet certain standards and placing restrictions on greenhouse gas emissions to mitigate concerns over global climate changes;

- changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension plan, which can affect future funding obligations, pension expense and pension plan liabilities;

- volatility and illiquidity in wholesale energy markets, including the availability of willing buyers and sellers, and prices of purchased energy and demand for energy sales;

- unplanned outages at any of our generating facilities or the inability of facilities to operate as intended;

- the outcome of pending regulatory and legal proceedings arising out of the western energy crisis of 2000 and 2001, including possible refunds;

the outcome of legal proceedings and other contingencies;

changes in, and compliance with, environmental and endangered species laws, regulations, decisions and policies, including present and potential environmental remediation costs;

wholesale and retail competition including, but not limited to, alternative energy sources, suppliers and delivery arrangements;

the ability to comply with the terms of the licenses for our hydroelectric generating facilities at cost-effective levels;

natural disasters that can disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies and support services;

explosions, fires, accidents, or mechanical breakdowns that may occur while operating and maintaining our generation, transmission and distribution systems;

blackouts or disruptions of interconnected transmission systems;

disruption to information systems, automated controls and other technologies that we rely on for operations, communications and customer service;

the potential for terrorist attacks, cyber security attacks or other malicious acts, that cause damage to our utility assets, as well as the national economy in general; including the impact of acts of terrorism, cyber security attacks or vandalism that damage or disrupt information technology systems;

delays or changes in construction costs, and/or our ability to obtain required permits and materials for present or prospective facilities;

changes in the long-term climate of the Pacific Northwest, which can affect, among other things, customer demand patterns and the volume and timing of streamflows to our hydroelectric resources;

changes in industrial, commercial and residential growth and demographic patterns in our service territory or the loss of significant customers;

the loss of key suppliers for materials or services;

default or nonperformance on the part of any parties from which we purchase and/or sell capacity or energy;

deterioration in the creditworthiness of our customers and counterparties;

the effect of any potential decline in our credit ratings, including impeded access to capital markets, higher interest costs, and certain covenants with ratings triggers in our financing arrangements and wholesale energy contracts;

increasing health care costs and the resulting effect on health insurance provided to our employees and retirees;

increasing costs of insurance, more restricted coverage terms and our ability to obtain insurance;
work force issues, including changes in collective bargaining unit agreements, strikes, work stoppages 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, among other things, costly litigation and a decline in our common stock price;

changes in technologies, possibly making some of the current technology obsolete;

- changes in tax rates and/or policies; 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 factors emerge from time to time, and it is not possible for us to predict all such factors, nor can we assess the effect of each such factor on our business or the extent that any such factor or combination of factors may cause actual results to differ materially from those contained in any forward-looking statement.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Three Months Ended September 30

Dollars in thousands, except per share amounts

(Unaudited)

	2011	2010
Operating Revenues:		
Utility revenues	$ 301,551	$ 331,092
Non-utility revenues	42,159	36,080
Total operating revenues	343,710	367,172
Operating Expenses:		
Utility operating expenses:		
Resource costs	171,393	201,113
Other operating expenses	60,579	59,961
Depreciation and amortization	26,341	24,918
Taxes other than income taxes	16,829	15,842
Non-utility operating expenses:		
Other operating expenses	31,726	25,862
Depreciation and amortization	1,964	1,732
Total operating expenses	308,832	329,428
Income from operations	34,878	37,744
Interest expense	18,703	18,830
Interest expense to affiliated trusts	152	175
Capitalized interest	(957)	(432)
Other expense-net	1,626	807
Income before income taxes	15,354	18,364
Income tax expense	3,717	5,030
Net income	11,637	13,334
Less: Net income attributable to noncontrolling interests	(935)	(988)
Net income attributable to Avista Corporation	$ 10,702	$ 12,346
Weighted-average common shares outstanding (thousands), basic	58,057	55,616
Weighted-average common shares outstanding (thousands), diluted	58,232	55,801
Earnings per common share attributable to Avista Corporation:		
Basic	$ 0.18	$ 0.22
Diluted	$ 0.18	$ 0.22
Dividends paid per common share	$ 0.275	$ 0.25

The Accompanying Notes are an Integral Part of These Statements.

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CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Nine Months Ended September 30

Dollars in thousands, except per share amounts

(Unaudited)

	2011	2010
Operating Revenues:		
Utility revenues	$ 1,059,221	$ 1,080,340
Non-utility revenues	121,632	103,980
Total operating revenues	1,180,853	1,184,320
Operating Expenses:		
Utility operating expenses:		
Resource costs	575,290	628,864
Other operating expenses	188,961	174,044
Depreciation and amortization	78,600	73,890
Taxes other than income taxes	61,521	54,879
Non-utility operating expenses:		
Other operating expenses	95,581	80,024
Depreciation and amortization	5,673	5,302
Total operating expenses	1,005,626	1,017,003
Income from operations	175,227	167,317
Interest expense	55,415	57,058
Interest expense to affiliated trusts	455	480
Capitalized interest	(2,209)	(1,126)
Other expense-net	3,061	3,475
Income before income taxes	118,505	107,430
Income tax expense	40,937	38,732
Net income	77,568	68,698
Less: Net income attributable to noncontrolling interests	(1,947)	(2,002)
Net income attributable to Avista Corporation	$ 75,621	$ 66,696
Weighted-average common shares outstanding (thousands), basic	57,731	55,175
Weighted-average common shares outstanding (thousands), diluted	57,934	55,384
Earnings per common share attributable to Avista Corporation:		
Basic	$ 1.31	$ 1.21
Diluted	$ 1.30	$ 1.20
Dividends paid per common share	$ 0.825	$ 0.75

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

For the Three Months Ended September 30

Dollars in thousands

(Unaudited)

	2011	2010
Net income	$ 11,637	$ 13,334
Other Comprehensive Income:		
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $66 and $19, respectively	123	36
Total other comprehensive income	123	36
Comprehensive income	11,760	13,370
Comprehensive income attributable to noncontrolling interests	(935)	(988)
Comprehensive income attributable to Avista Corporation	$ 10,825	$ 12,382

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

	2011	2010
Net income	$ 77,568	$ 68,698
Other Comprehensive Income (Loss):		
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $(7) and $58, respectively	(13)	108
Total other comprehensive income (loss)	(13)	108
Comprehensive income	77,555	68,806
Comprehensive income attributable to noncontrolling interests	(1,947)	(2,002)
Comprehensive income attributable to Avista Corporation	$ 75,608	$ 66,804

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands

(Unaudited)

	September 30, 2011	December 31, 2010
Assets:		
Current Assets:		
Cash and cash equivalents	$ 78,103	$ 69,413
Accounts and notes receivable-less allowances of $43,750 and $44,883	155,072	230,229
Utility energy commodity derivative assets	489	2,592
Regulatory asset for utility derivatives	52,784	48,891
Investments and funds held for customers	104,521	100,543
Materials and supplies, fuel stock and natural gas stored	64,878	48,530
Deferred income taxes	23,470	28,822
Income taxes receivable	34,376	19,069
Other current assets	34,560	31,476
Total current assets	548,253	579,565
Net Utility Property:		
Utility plant in service	3,832,705	3,713,885
Construction work in progress	67,393	62,051
Total	3,900,098	3,775,936
Less: Accumulated depreciation and amortization	1,098,579	1,061,699
Total net utility property	2,801,519	2,714,237
Other Non-current Assets:		
Investment in exchange power-net	19,396	21,233
Investment in affiliated trusts	11,547	11,547
Goodwill	26,112	25,935
Long-term energy contract receivable of Spokane Energy	65,013	62,525
Other intangibles, property and investments-net	64,585	74,553
Total other non-current assets	186,653	195,793
Deferred Charges:		
Regulatory assets for deferred income tax	86,586	90,025
Regulatory assets for pensions and other postretirement benefits	185,412	178,985
Other regulatory assets	116,093	112,830
Non-current utility energy commodity derivative assets	5,595	15,261
Non-current regulatory asset for utility derivatives	16,802	15,724
Power deferrals	593	18,305
Other deferred charges	21,080	19,370
Total deferred charges	432,161	450,500
Total assets	$ 3,968,586	$ 3,940,095

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

Dollars in thousands

(Unaudited)

	September 30, 2011	December 31, 2010
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 154,249	$ 171,707
Customer fund obligations	104,521	100,543
Current portion of long-term debt	7,370	358
Current portion of nonrecourse long-term debt of Spokane Energy	13,357	12,463
Short-term borrowings	96,500	110,000
Utility energy commodity derivative liabilities	53,267	51,483
Natural gas deferrals	8,036	22,074
Other current liabilities	139,252	110,547
Total current liabilities	576,552	579,175
Long-term debt	1,084,661	1,101,499
Nonrecourse long-term debt of Spokane Energy	36,319	46,471
Long-term debt to affiliated trusts	51,547	51,547
Regulatory liability for utility plant retirement costs	226,206	223,131
Pensions and other postretirement benefits	162,548	161,189
Deferred income taxes	516,300	495,474
Other non-current liabilities and deferred credits	91,995	109,703
Total liabilities	2,746,128	2,768,189
Commitments and Contingencies (See Notes to Condensed Consolidated Financial Statements)		
Redeemable Noncontrolling Interests	52,070	46,722
Equity:		
Avista Corporation Stockholders Equity:		
Common stock, no par value; 200,000,000 shares authorized; 58,200,997 and 57,119,723 shares outstanding	848,709	827,592
Accumulated other comprehensive loss	(4,339)	(4,326)
Retained earnings	326,548	302,518
Total Avista Corporation stockholders equity	1,170,918	1,125,784
Noncontrolling Interests	(530)	(600)
Total equity	1,170,388	1,125,184
Total liabilities and equity	$ 3,968,586	$ 3,940,095

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

For the Nine Months Ended September 30

Dollars in thousands

(Unaudited)

	2011	2010
Operating Activities:		
Net income	$ 77,568	$ 68,698
Non-cash items included in net income:		
Depreciation and amortization	84,273	79,192
Provision for deferred income taxes	30,783	10,490
Power and natural gas cost amortizations (deferrals), net	9,470	(16,804)
Amortization of debt expense and premium	3,186	3,214
Equity-related AFUDC	(1,655)	(1,436)
Other	32,958	36,524
Contributions to defined benefit pension plan	(26,000)	(21,000)
Changes in working capital components:		
Accounts and notes receivable	76,285	50,944
Materials and supplies, fuel stock and natural gas stored	(16,260)	(19,146)
Other current assets	(28,167)	13,746
Accounts payable	(11,994)	(10,064)
Other current liabilities	9,977	7,351
Net cash provided by operating activities	240,424	201,709
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(169,598)	(138,083)
Other capital expenditures	(2,730)	(1,300)
Federal grant payments received	13,398	4,634
Cash paid by subsidiary for acquisition, net of cash received	(199)	
Decrease (increase) in funds held for customers	43,321	(16,366)
Purchase of securities available for sale	(47,299)	
Other	(4,604)	(1,296)
Net cash used in investing activities	(167,711)	(152,411)
Financing Activities:		
Net decrease in short-term borrowings	(13,500)	(12,000)
Borrowings from Ecova line of credit		2,300
Repayment of borrowings from Ecova line of credit		(8,000)
Redemption and maturity of long-term debt	(204)	(10,236)
Maturity of nonrecourse long-term debt of Spokane Energy	(9,258)	(8,447)
Long-term debt and short-term borrowing issuance costs	(2,362)	(258)
Cash paid for settlement of interest rate swap agreements	(10,557)	
Issuance of common stock	21,216	34,677
Cash dividends paid	(47,685)	(41,385)
Purchase of subsidiary noncontrolling interest	(6,179)	(2,593)
Increase in customer fund obligations	3,978	16,366
Other	528	(75)
Net cash used in financing activities	(64,023)	(29,651)

Net increase in cash and cash equivalents	8,690	19,647
Cash and cash equivalents at beginning of period	69,413	37,035
Cash and cash equivalents at end of period	$ 78,103	$ 56,682
Supplemental Cash Flow Information:		
Cash paid during the period:		
Interest	$ 41,582	$ 44,985
Income taxes	24,506	11,161
Non-cash financing and investing activities:		
Accounts payable for capital expenditures	2,642	6,279
Utility property acquired under capital leases		5,300
Redeemable noncontrolling interests	5,147	7,458

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

AND REDEEMABLE NONCONTROLLING INTERESTS

Avista Corporation

For the Nine Months Ended September 30

Dollars in thousands

(Unaudited)

	2011	2010
Common Stock, Shares:		
Shares outstanding at beginning of period	57,119,723	54,836,781
Issuance of common stock	1,081,274	1,733,788
Shares outstanding at end of period	58,200,997	56,570,569
Common Stock, Amount:		
Balance at beginning of period	$ 827,592	$ 778,647
Equity compensation expense	2,718	2,308
Issuance of common stock, net of issuance costs	21,216	34,677
Equity transactions of consolidated subsidiaries	(2,817)	(621)
Balance at end of period	848,709	815,011
Accumulated Other Comprehensive Loss:		
Balance at beginning of period	(4,326)	(2,350)
Other comprehensive income (loss)	(13)	108
Balance at end of period	(4,339)	(2,242)
Retained Earnings:		
Balance at beginning of period	302,518	274,990
Net income attributable to Avista Corporation	75,621	66,696
Cash dividends paid (common stock)	(47,685)	(41,385)
Valuation adjustments and other noncontrolling interests activity	(3,906)	(6,580)
Balance at end of period	326,548	293,721
Total Avista Corporation stockholders equity	1,170,918	1,106,490
Noncontrolling Interests:		
Balance at beginning of period	(600)	(673)
Net income attributable to noncontrolling interests	95	48
Other	(25)	6
Balance at end of period	(530)	(619)
Total equity	$ 1,170,388	$ 1,105,871
Redeemable Noncontrolling Interests:		
Balance at beginning of period	$ 46,722	$ 34,833

Net income attributable to noncontrolling interests	1,852	1,954
Purchase of subsidiary noncontrolling interests	(6,179)	(2,593)
Valuation adjustments and other noncontrolling interests activity	9,675	8,959
Balance at end of period	$ 52,070	$ 43,153

The Accompanying Notes are an Integral Part of These Statements.

AVISTA CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

The accompanying condensed consolidated financial statements of Avista Corporation (Avista Corp. or the Company) for the interim periods ended September 30, 2011 and 2010 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, 2010 (2010 Form 10-K). Please refer to the section Acronyms and Terms in the 2010 Form 10-K for definitions of terms. The acronyms and terms are an integral part of these condensed consolidated financial statements.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corp. is an energy company engaged in the generation, transmission and distribution of energy, as well as other energy-related businesses. Avista Utilities is an operating division of Avista Corp., comprising the regulated utility operations. Avista Utilities generates, transmits and distributes electricity in parts of eastern Washington and northern Idaho. In addition, Avista Utilities has electric generating facilities in Montana and northern Oregon. Avista Utilities also provides natural gas distribution service in parts of eastern Washington and northern Idaho, as well as parts of northeast and southwest Oregon. Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility businesses, except Spokane Energy, LLC (Spokane Energy). Avista Capital s subsidiaries include Ecova, Inc. (Ecova), formerly Advantage IQ, Inc. (Advantage IQ), a 79.2 percent owned subsidiary as of September 30, 2011. Ecova is a provider of energy efficiency and other facility information and cost management programs and services for multi-site customers and utilities throughout North America. See Note 12 for business segment information.

Basis of Reporting

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

Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on net income. These taxes are generally based on revenues or the value of property. Utility related taxes collected from customers (primarily state excise taxes and city utility taxes) are recorded as operating revenue and expense and totaled the following amounts for the three and nine months ended September 30 (dollars in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Utility taxes	$ 10,270	$ 9,742	$ 41,551	$ 37,453

Other Expense - Net

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

	Three months ended September 30		, Nine months ended September 30,	
	2011	2010	2011	2010
Interest income	$ (455)	$ (393)	$ (1,029)	$ (991)
Interest on regulatory deferrals	(15)	(58)	(83)	(188)
Equity-related AFUDC	(421)	(552)	(1,655)	(1,436)
Net loss on investments	560	137	597	766
Other expense	1,957	1,676	5,466	5,718
Other income		(3)	(235)	(394)
Total	$ 1,626	$ 807	$ 3,061	$ 3,475

AVISTA CORPORATION

Investments and Funds Held for Customers and Customer Fund Obligations

In connection with the bill paying services, Ecova (formerly Advantage IQ) collects funds from its customers and remits the funds to the appropriate utility or other service provider. The funds collected are invested and classified as investments and funds held for customers and a related liability for customer fund obligations is recorded. Investments and funds held for customers include cash and cash equivalent investments and beginning in the three months ended September 30, 2011, investment securities classified as available for sale. Investments and funds held for customers as of September 30, 2011 are as follows (dollars in thousands):

	Amortized Cost	Unrealized Gain (Loss)	Fair Value
Money market funds	$ 57,323	$	$ 57,323
Securities available for sale:			
U.S. government agency	34,800	17	34,817
Municipal	429		429
Corporate fixed income - financial	7,214	(12)	7,202
Corporate fixed income - industrial	4,771	(21)	4,750
Total securities available for sale	47,214	(16)	47,198
Total investments and funds held for customers	$ 104,537	$ (16)	$ 104,521

All investments and funds held for customers at December 31, 2010 were in money market funds. The Company has classified investments and funds held for customers as a current asset since these funds are held solely for the purpose of satisfying the customer fund obligations. Approximately 92 percent of the investment portfolio is rated AA or higher as of September 30, 2011 by Nationally Recognized Statistical Rating Organizations. All fixed income securities were rated as investment grade as of September 30, 2011. Based on the Company s analysis, securities available for sale do not meet the criteria for other-than-temporary impairment as of September 30, 2011. Contractual maturities of securities available for sale as of September 30, 2011 are as follows (dollars in thousands):

	One year or less	One year to two years	Two years to three years	Three years to four years	Four years to five years	After five years
Maturity date	$ 16,034	$ 2,529	$ 11,486	$ 4,142	$ 8,022	$ 4,985

Goodwill

Goodwill arising from acquisitions represents the excess of the purchase price over the estimated fair value of net assets acquired. The Company evaluates goodwill for impairment using a discounted cash flow model on at least an annual basis or more frequently if impairment indicators arise. The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2010 for the other businesses and as of December 31, 2010 for Ecova and determined that goodwill was not impaired at that time. The changes in the carrying amount of goodwill are as follows (dollars in thousands):

	Ecova	Other	Accumulated Impairment Losses	Total
Balance as of the December 31, 2010	$ 20,689	$ 12,979	$ (7,733)	$ 25,935
Adjustments	177			177

Balance as of the September 30, 2011	$ 20,866	$ 12,979	$ (7,733)	$ 26,112

Accumulated impairment losses are attributable to the other businesses.

Other Intangibles

Other Intangibles primarily represent the amounts assigned to client relationships related to the Ecova acquisition of Cadence Network in 2008 (estimated amortization period of 12 years), Ecos in 2009 (estimated amortization period of 3 years) and The Loyalton Group in 2010 (estimated amortization period of 6 years), software development costs (estimated amortization period of 5 to 7 years) and other. Other Intangibles are included in other intangibles, property and investments - net on the Condensed Consolidated Balance Sheets. Amortization expense related to Other Intangibles was as follows for the three and nine months ended September 30 (dollars in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Other intangible amortization	$ 1,145	$ 933	$ 3,298	$ 2,840

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

	2011	2012	2013	2014	2015
Estimated amortization expense	$ 1,290	$ 4,709	$ 3,980	$ 3,077	$ 1,690

The gross carrying amount and accumulated amortization of Other Intangibles as of September 30, 2011 and December 31, 2010 are as follows (dollars in thousands):

	September 30, 2011	December 31, 2010
Client relationships	$ 11,459	$ 11,459
Software development costs	21,368	19,139
Other	1,501	1,450
Total other intangibles	34,328	32,048
Client relationships accumulated amortization	(3,225)	(2,156)
Software development costs accumulated amortization	(11,110)	(8,985)
Other accumulated amortization	(910)	(806)
Total accumulated amortization	(15,245)	(11,947)
Total other intangibles - net	$ 19,083	$ 20,101

Derivative Assets and Liabilities

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

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

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If at some point in the future the Company determines that it no longer meets the criteria for continued application of regulatory accounting practices for all or a portion of its regulated operations, the Company could be:

- required to write off its regulatory assets, and
- precluded from the future deferral of costs not recovered through rates at the time such costs are incurred, even if the Company expected to recover such costs in the future.

Contingencies

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

NOTE 2. NEW ACCOUNTING STANDARDS

Effective January 1, 2010, the Company adopted Accounting Standards Update (ASU) No. 2010-06, Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements. This ASU amends guidance related to the disclosures of fair value measurements. In particular, it amends Accounting Standards Codification (ASC) 820-10 to clarify existing disclosures and

provides for further disaggregation within classes of assets and liabilities, and further disclosure about inputs and valuation techniques. It also requires disclosure of significant transfers between Level 1 and Level 2 within the fair value hierarchy and separate disclosure of purchases, sales, issuances and settlements in the reconciliation of Level 3 activity (this is required beginning in 2011). See Note 9 for the Company s fair value disclosures. In May 2011, the Financial Accounting Standards Board (FASB) issued ASU No. 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs. This ASU will require enhanced disclosures for fair value measurements, including quantitative sensitivity analysis of unobservable inputs used in Level 3 fair value measurements. The ASU also clarifies the FASB s intent about the application of existing fair value measurement requirements. The Company will be required to adopt this ASU effective January 1, 2012. The Company is evaluating the impact this ASU will have on its financial condition, results of operations and disclosures.

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

NOTE 3. VARIABLE INTEREST ENTITIES

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

Avista Corp. has a variable interest in the PPA. Accordingly, Avista Corp. made an evaluation of which interest holders have the power to direct the activities that most significantly impact the economic performance of the entity and which interest holders have the obligation to absorb losses or receive benefits that could be significant to the entity. Avista Corp. pays a fixed capacity and operations and maintenance payment and certain monthly variable costs under the PPA. Under the terms of the PPA, Avista Corp. makes the dispatch decisions, provides all natural gas fuel and receives all of the electric energy output from the Lancaster Plant. However, Rathdrum Power LLC (the owner) controls the daily operation of the Lancaster Plant and makes operating and maintenance decisions. Rathdrum Power LLC controls all of the rights and obligations of the Lancaster Plant after the expiration of the PPA in 2026. It is estimated that the plant will have 15 to 25 years of useful life after that time. Rathdrum Power LLC bears the maintenance risk of the plant and will receive the residual value of the Lancaster Plant. Avista Corp. has no debt or equity investments in the Lancaster Plant and does not provide financial support through liquidity arrangements or other commitments (other than the PPA). Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Lancaster Plant. Accordingly, neither the Lancaster Plant nor Rathdrum Power LLC is included in Avista Corp. s condensed consolidated financial statements. The Company has a future contractual obligation of approximately $346 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.

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Spokane Energy is a special purpose limited liability company and all of its membership capital is owned by Avista Corp. Spokane Energy was formed in December 1998 to assume ownership of a fixed rate electric capacity contract between Avista Corp. and Portland General Electric Company.

Spokane Energy borrowed $145.0 million from a funding trust and paid $143.4 million to Avista Corp. to acquire its rights under the contract. The loan, which matures in January 2015, is structured so that Spokane Energy is the sole obligor. Avista Corp. has no obligation or liability related to this loan.

The cost of acquiring the energy contract is being amortized and matched with sales revenue over the life of the contract using the effective interest method. Avista Corp. acts as the servicer under the contract and performs scheduling, billing and collection functions.

Pursuant to orders from the WUTC and the IPUC, Avista Corp. fully amortized the $143.4 million received by the end of 2002.

Prior to 2010, Avista Corp. did not consolidate Spokane Energy because Spokane Energy met the definition of a qualified special purpose entity (QSPE). As the amendments to ASC 810 and 860 eliminated the concept of a QSPE, Avista Corp. evaluated Spokane Energy for consolidation as a variable interest entity and determined that it was required to consolidate the entity. This determination was based primarily on Avista Corp. controlling the significant activities of Spokane Energy, owning all of the member capital of Spokane Energy, and receiving the majority of the residual benefits upon liquidation of the entity.

NOTE 4. REDEEMABLE NONCONTROLLING INTERESTS AND SUBSIDIARY ACQUISITIONS

The acquisition of Cadence Network in July 2008 was funded with the issuance of Ecova (formerly Advantage IQ) common stock. Under the transaction agreement, the previous owners of Cadence Network can exercise a right to have their shares of Ecova common stock redeemed during July 2011 or July 2012 if Ecova is not liquidated through either an initial public offering or sale of the business to a third party. These rights were not exercised during July 2011. Their redemption rights expire July 31, 2012. The redemption price would be determined based on the fair market value of Ecova at the time of the redemption election as determined by certain independent parties. Additionally, certain minority shareholders and option holders of Ecova have the right to put their shares back to Ecova at their discretion during an annual put window. The following details redeemable noncontrolling interests as of September 30, 2011 and December 31, 2010 (dollars in thousands):

	September 30, 2011	December 31, 2010
Previous owners of Cadence Network	$ 39,048	$ 38,098
Stock options and other outstanding redeemable stock	13,022	8,624
Total redeemable noncontrolling interests	$ 52,070	$ 46,722

In January 2011, Avista Capital purchased shares held by one of the previous owners of Cadence Network for $5.6 million.

On December 31, 2010, Ecova acquired substantially all of the assets and liabilities of The Loyalton Group (Loyalton), a Minneapolis-based energy management firm providing energy procurement and price risk management solutions. The acquisition of Loyalton was funded primarily through available cash at Ecova plus contingent consideration based on revenue targets over the next three years. The acquired assets and liabilities assumed of Loyalton were recorded at their respective estimated fair values as of the date of acquisition. The results of operations of Loyalton are included in the condensed consolidated financial statements beginning January 1, 2011.

In January 2011, Ecova acquired substantially all of the assets and liabilities of Building Knowledge Networks (BKN), a Seattle-based real-time building energy management services provider. The acquisition of BKN was funded through available cash at Ecova.

Pro forma disclosures reflecting the effects of the acquisitions of Loyalton and BKN 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. Market risk may also be influenced by market participants nonperformance of their contractual obligations and commitments, which affects the supply of, or demand for, the commodity. 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 risk assessment and risk management policies, including the Company s material financial and accounting risk exposures and the steps management has undertaken to control them.

As part of its resource procurement and management operations in the electric business, Avista Utilities engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Utilities load obligations and the use of these resources to capture available economic value. Avista Utilities sells and purchases wholesale electric capacity and energy and fuel as part of the process of acquiring and balancing resources to serve its load obligations. These transactions range from terms of one hour up to multiple years.

Avista Utilities makes continuing projections of:

- electric loads at various points in time (ranging from one 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, Avista Utilities makes purchases and sales of electric capacity and energy and fuel to match expected resources to expected electric load requirements. Resource optimization involves generating plant dispatch and scheduling available resources and also includes transactions such as:

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

Avista Utilities optimization process includes entering into hedging transactions to manage risks.

As part of its resource procurement and management operations in the 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
- sales of excess natural gas storage capacity.

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The following table presents the underlying energy commodity derivative volumes as of September 30, 2011 that are expected to settle in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical MWH	Financial MWH	Physical mmBTUs	Financial mmBTUs	Physical MWH	Financial MWH	Physical mmBTUs	Financial mmBTUs
2011	609	343	12,539	29,225	184	113	5,407	26,983
2012	950	2,150	17,802	61,266	377	656	2,893	61,260
2013	398	1,751	7,105	52,155	254	1,013	1,533	49,428
2014	366		2,933	8,513	286	123	1,050	3,900
2015	379		675	1,125	286			
Thereafter	1,315				1,017			

Foreign Currency Exchange Contracts

A significant portion of Avista Utilities natural gas supply (including fuel for power generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of Avista Utilities short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices and settled within sixty days with U.S. dollars. Avista Utilities economically hedges a portion of the foreign currency risk by purchasing Canadian currency contracts when such commodity transactions are initiated. This risk has not had a material effect on the Company s financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations were included with natural gas supply costs for ratemaking. The following table summarizes the foreign currency hedges that the Company has entered into as of September 30, 2011 and December 31, 2010 (dollars in thousands):

	September 30, 2011	December 31, 2010
Number of contracts	30	29
Notional amount (in United States dollars)	$ 11,310	$ 10,916
Notional amount (in Canadian dollars)	11,208	10,989
Derivative in other current assets (liabilities)	(523)	116

Interest Rate Swap Agreements

Avista Corp. enters into forward-starting interest rate swap agreements to manage the risk associated with changes in interest rates and the impact on future interest payments. These interest rate swap agreements relate to the interest payments for anticipated debt issuances. These interest rate swap agreements are considered economic hedges against fluctuations in future cash flows associated with changes in interest rates. The following table summarizes the interest rate swaps that the Company has entered into as of September 30, 2011 and December 31, 2010 (dollars in thousands):

	September 30, 2011	December 31, 2010
Number of contracts	3	2
Notional amount	$ 75,000	$ 50,000
Mandatory cash settlement date	July 2012	July 2012
Number of contracts	2	
Notional amount	$ 85,000	
Mandatory cash settlement date	June 2013	

Derivative asset		127
Derivative liability	(14,225)	(53)

In September 2011, the Company cash settled interest rate swap contracts (notional amount of $85.0 million) and paid a total of $10.6 million. The interest rate swap contracts were entered during the third quarter of 2011 and were settled in connection with the pricing of $85.0 million of First Mortgage Bonds (see Note 8). Upon settlement of the interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the life of the forecasted interest payments.

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Derivative Instruments Summary

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of September 30, 2011 (in thousands):

		Fair Value		
Derivative	Balance Sheet Location	Asset	Liability	Net Asset (Liability)
Foreign currency contracts	Other current liabilities	$	$ (523)	$ (523)
Interest rate contracts	Other current liabilities		(14,077)	(14,077)
Interest rate contracts	Other non-current liabilities and deferred credits		(148)	(148)
Commodity contracts	Current utility energy commodity derivative assets	1,478	(989)	489
Commodity contracts	Non-current utility energy commodity derivative assets	12,345	(6,750)	5,595
Commodity contracts	Current utility energy commodity derivative liabilities	24,668	(77,935)	(53,267)
Commodity contracts	Other non-current liabilities and deferred credits	20,643	(43,040)	(22,397)
Total derivative instruments recorded on the balance sheet		$ 59,134	$ (143,462)	$ (84,328)

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of December 31, 2010 (in thousands):

		Fair Value		
Derivative	Balance Sheet Location	Asset	Liability	Net Asset (Liability)
Foreign currency contracts	Other current assets	$ 116	$	$ 116
Interest rate contracts	Other intangibles, property and investments-net	127		127
Interest rate contracts	Other non-current liabilities and deferred credits		(53)	(53)
Commodity contracts	Current utility energy commodity derivative assets	6,293	(3,701)	2,592
Commodity contracts	Non-current utility energy commodity derivative assets	21,249	(5,988)	15,261
Commodity contracts	Current utility energy commodity derivative liabilities	5,934	(57,417)	(51,483)
Commodity contracts	Other non-current liabilities and deferred credits	1,386	(32,371)	(30,985)
Total derivative instruments recorded on the balance sheet		$ 35,105	$ (99,530)	$ (64,425)

Exposure to Demands for Collateral

The Company s derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement, in the event of a downgrade in the Company s credit ratings or changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against the Company s credit facilities and cash. The Company actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements. As of September 30, 2011, the Company had cash deposited as collateral of $10.2 million and letters of credit of $7.2 million outstanding related to its energy derivative contracts.

Certain of the Company s derivative instruments contain provisions that require the Company to maintain an investment grade credit rating from the major credit rating agencies. If the Company s credit ratings were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position as of September 30, 2011 was $98.6 million. If the credit-risk-related contingent features underlying these agreements were triggered on September 30, 2011, the Company would be required to post $48.4 million of collateral to its counterparties.

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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. Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established. 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.

Should a counterparty, customer or supplier fail to perform, the Company may be required to honor the underlying commitment or to replace existing contracts with contracts at then-current market prices. The Company seeks to mitigate credit risk by:

- entering into bilateral contracts that specify credit terms and protections against default,
- applying credit limits and duration criteria to existing and prospective counterparties,
- actively monitoring current credit exposures, and
- conducting transactions on exchanges with clearing arrangements that essentially eliminate counterparty default risk.

These credit policies include an evaluation of the financial condition and credit ratings of counterparties, collateral requirements or other credit enhancements, such as letters of credit or parent company guarantees. The Company also uses standardized agreements that allow for the netting or offsetting of positive and negative exposures associated with a single counterparty or affiliated group.

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

- electric utilities,
- electric generators and transmission providers,
- natural gas producers and pipelines,
- financial institutions, 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 margin agreements with certain counterparties and margin calls are periodically made and/or received. Margin calls are triggered when exposures exceed predetermined 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 $21 million in cash to the pension plan in 2010. The Company contributed $26 million in cash to the pension plan in 2011 (with no further contributions planned for the remainder of 2011).

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.

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

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

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

	Pension Benefits		Other Post-retirement Benefits	
	2011	2010	2011	2010
Three months ended September 30:				
Service cost	$ 3,303	$ 2,878	$ 433	$ 219
Interest cost	6,017	5,823	1,005	631
Expected return on plan assets	(5,775)	(5,347)	(400)	(341)
Transition obligation recognition			125	126
Amortization of prior service cost	125	163	(37)	(37)
Net loss recognition	2,506	1,857	960	297
Net periodic benefit cost	$ 6,176	$ 5,374	$ 2,086	$ 895
Nine months ended September 30:				
Service cost	$ 9,548	$ 8,634	$ 1,299	$ 640
Interest cost	18,143	17,469	3,015	1,881
Expected return on plan assets	(17,141)	(16,041)	(1,200)	(1,023)
Transition obligation recognition			375	378
Amortization of prior service cost	369	489	(111)	(111)
Net loss recognition	6,909	5,490	2,634	825
Net periodic benefit cost	$ 17,828	$ 16,041	$ 6,012	$ 2,590

NOTE 7. SHORT-TERM BORROWINGS

Avista Corp.

In February 2011, Avista Corp. entered into a new committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2015 that replaced its $320.0 million and $75.0 million committed lines of credit.

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

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of consolidated total debt to consolidated total capitalization of Avista Corp. to be greater than 65 percent at any time. As of September 30, 2011, the Company was in compliance with this covenant.

Balances outstanding under the Company s revolving committed lines of credit were as follows as of September 30, 2011 and December 31, 2010 (dollars in thousands):

	September 30, 2011	December 31, 2010
Balance outstanding at end of period	$ 96,500	$ 110,000
Letters of credit outstanding at end of period	$ 14,883	$ 27,126

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Ecova

In April 2011, Ecova entered into a new $40.0 million three-year committed line of credit agreement with a financial institution that replaced its $15.0 million committed credit agreement that had an expiration date of May 2011. The credit agreement is secured by substantially all of Ecova s assets. There were no borrowings outstanding under Ecova s credit agreements as of September 30, 2011 and December 31, 2010.

NOTE 8. LONG-TERM DEBT

The following details long-term debt outstanding as of September 30, 2011 and December 31, 2010 (dollars in thousands):

Maturity Year	Description	Interest Rate	September 30, 2011	December 31, 2010
2012	Secured Medium-Term Notes	7.37%	$ 7,000	$ 7,000
2013	First Mortgage Bonds	1.68%	50,000	50,000
2018	First Mortgage Bonds	5.95%	250,000	250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2020	First Mortgage Bonds	3.89%	52,000	52,000
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (2)	(2)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
	Total secured long-term debt		1,178,700	1,178,700
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Capital leases and other long-term debt		5,447	5,500
	Settled interest rate swaps		(10,849)	(951)
	Unamortized debt discount		(1,667)	(1,792)
	Total		1,175,731	1,185,557
	Secured Pollution Control Bonds held by Avista Corporation (1) (2)		(83,700)	(83,700)
	Current portion of long-term debt		(7,370)	(358)
	Total long-term debt		$ 1,084,661	$ 1,101,499

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

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

In October 2011, the Company entered into a bond purchase agreement with certain institutional investors in the private placement market for the purpose of issuing $85.0 million of 4.45 percent First Mortgage Bonds due in 2041. The new First Mortgage Bonds will be issued under and in accordance with the Mortgage and Deed of Trust, dated as of June 1, 1939, from the Company to Citibank, N.A., trustee, as amended and supplemented by various supplemental indentures and other instruments. The issuance of the bonds will occur at closing in December 2011. The total net proceeds from the sale of the new bonds will be used to repay a portion of the borrowings outstanding under the Company s $400.0 million committed line of credit.

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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 following table sets forth the carrying value and estimated fair value of the Company s financial instruments not reported at estimated fair value on the Condensed Consolidated Balance Sheets as of September 30, 2011 and December 31, 2010 (dollars in thousands):

	September 30, 2011		December 31, 2010	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt	$ 1,099,100	$ 1,302,447	$ 1,099,100	$ 1,139,765
Nonrecourse long-term debt	49,676	55,725	58,934	64,795
Long-term debt to affiliated trusts	51,547	43,805	51,547	37,114

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

The 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.

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The following table discloses by level within the fair value hierarchy the Company s assets and liabilities measured and reported on the Condensed Consolidated Balance Sheets as of September 30, 2011 and December 31, 2010 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty Netting (1)	Total
September 30, 2011					
Assets:					
Energy commodity derivatives	$	$ 46,744	$ 12,388	$ (53,048)	$ 6,084
Investments and funds held for customers:					
Money market funds (2)	57,323				57,323
Securities available for sale:					
U.S. government agency		34,817			34,817
Municipal		429			429
Corporate fixed income financial		7,202			7,202
Corporate fixed income industrial -		4,750			4,750
Funds held in trust account of Spokane Energy	1,600				1,600
Deferred compensation assets:					
Fixed income securities (3)	2,299				2,299
Equity securities (3)	5,355				5,355
Total	$ 66,577	$ 93,942	$ 12,388	$ (53,048)	$ 119,859
Liabilities:					
Energy commodity derivatives	$	$ 116,564	$ 12,148	$ (53,048)	$ 75,664
Foreign currency derivatives		523			523
Interest rate swaps		14,225			14,225
Energy commodity derivatives	$	$ 131,312	$ 12,148	$ (53,048)	$ 90,412
December 31, 2010					
Assets:					
Energy commodity derivatives	$	$ 15,124	$ 19,739	$ (17,010)	$ 17,853
Interest rate swaps		127			127
Foreign currency derivatives		116			116
Investments and funds held for customers (2)	100,543				100,543
Funds held in trust account of Spokane Energy	1,600				1,600
Deferred compensation assets:					
Fixed income securities (3)	1,854				1,854
Equity securities (3)	6,211				6,211
Total	$ 110,208	$ 15,367	$ 19,739	$ (17,010)	$ 128,304
Liabilities:					
Energy commodity derivatives	$	$ 93,198	$ 6,280	$ (17,010)	$ 82,468
Interest rate swaps		53			53
Total	$	$ 93,251	$ 6,280	$ (17,010)	$ 82,521

(1) The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a legally enforceable master netting agreement exists.

(2) Represents amounts held in money market funds.

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

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

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For securities available for sale (held at Ecova) the Company uses a nationally recognized third party to obtain fair value and reviews these prices for accuracy using a variety of market tools and analysis. The Company s pricing vendor uses a generic model which uses standard inputs, 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. Further, the model uses Option Adjusted Spread and is a multidimensional relational model. All bonds valued using these techniques are classified as Level 2. All securities available for sale were deemed Level 2.

The Company also has certain contracts that, primarily due to the length of the respective contract, require the use of internally developed forward price estimates, which include significant inputs that may not be observable or corroborated in the market. These derivative contracts are included in Level 3. Refer to Note 5 for further discussion of the Company s energy commodity derivative assets and liabilities.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an Executive Deferral Plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $1.4 million as of September 30, 2011 and $1.2 million as of December 31, 2010.

The following table presents activity for energy commodity derivative assets and (liabilities) measured at fair value using significant unobservable inputs (Level 3) for the three and nine months ended September 30 (dollars in thousands):

	Assets		Liabilities	
	2011	2010	2011	2010
Three months ended September 30:				
Balance as of July 1	$ 17,032	$ 33,851	$ (9,687)	$ (4,381)
Total gains or losses (realized/unrealized):				
Included in net income				
Included in other comprehensive income				
Included in regulatory assets/liabilities (1)	(4,644)	(22,105)	(2,461)	(2,788)
Purchases				
Issuances				
Settlements				
Transfers from other categories				
Ending balance as of September 30	$ 12,388	$ 11,746	$ (12,148)	$ (7,169)
Nine months ended September 30:				
Balance as of January 1	$ 19,739	$ 57,276	$ (6,280)	$ (7,806)
Total gains or losses (realized/unrealized):				
Included in net income				
Included in other comprehensive income				
Included in regulatory assets/liabilities (1)	(7,351)	(43,181)	(3,409)	556
Purchases				
Issuances				
Settlements		(2,349)	1,945	81
Transfers from other categories (2)			(4,404)	
Ending balance as of September 30	$ 12,388	$ 11,746	$ (12,148)	$ (7,169)

(1)

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

(2) A derivative contract was reclassified from Level 2 to Level 3 during the nine months ended September 30, 2011 due to a particular unobservable input becoming more significant to the fair value measurement.

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NOTE 10. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORPORATION

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corporation for the three and nine months ended September 30 (in thousands, except per share amounts):

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Numerator:				
Net income attributable to Avista Corporation	$ 10,702	$ 12,346	$ 75,621	$ 66,696
Subsidiary earnings adjustment for dilutive securities	(170)	(92)	(340)	(170)
Adjusted net income attributable to Avista Corporation for computation of diluted earnings per common share	$ 10,532	$ 12,254	$ 75,281	$ 66,526
Denominator:				
Weighted-average number of common shares outstanding-basic	58,057	55,616	57,731	55,175
Effect of dilutive securities:				
Contingent stock awards	131	113	149	134
Stock options	44	72	54	75
Weighted-average number of common shares outstanding-diluted	58,232	55,801	57,934	55,384
Potential shares excluded in calculation (1)		198		198
Earnings per common share attributable to Avista Corporation:				
Basic	$ 0.18	$ 0.22	$ 1.31	$ 1.21
Diluted	$ 0.18	$ 0.22	$ 1.30	$ 1.20

(1) Certain stock options were excluded from the calculation because they were antidilutive, as the exercise price of the stock options was higher 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 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.

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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 adverse 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 adverse 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 at 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 directs both the CalISO and the CalPX to prepare and submit to the FERC their final refund rerun compliance filings. The FERC s order also directs the CalPX to pay past due principal amounts to governmental entities. As of September 30, 2011, Avista Energy s accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from the defaulting parties.

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

In September 2005, the Ninth Circuit held that the FERC did not have the authority to order refunds for sales made by municipal utilities in the California refund proceeding. In August 2006, the Ninth Circuit upheld October 2, 2000 as the refund effective date for the FPA section 206 refund proceeding, but remanded to the FERC its decision not to consider an FPA section 309 remedy for tariff violations prior to that date. A FERC hearing on that issue is scheduled to commence in March 2012. A May 2011 FERC order denied a motion filed by Avista Energy and Avista Utilities asking that the companies be dismissed from any further proceedings involving alleged tariff violations under FPA section 309. Avista Energy and Avista Utilities sought rehearing of that ruling in June 2011. As noted above, in Docket No. EL02-115, Avista Energy and Avista Utilities were absolved of any wrongdoing related to allegations of tariff violations during 2000 and 2001 and have argued that the doctrines of *res judicata* and collateral estoppel preclude relitigation of the same issues. The California AG, the CPUC, PG&E and SCE also 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. They also filed a petition for review of the May 2011 order at the Ninth Circuit.

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 will have a material adverse effect on its financial condition, results of operations or cash flows. 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.

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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 Department of Water Resources (CERS) in the Pacific Northwest and ultimately consumed in California. The Ninth Circuit expressly declined to direct the FERC to grant refunds. The Ninth Circuit denied petitions for rehearing by various parties, and remanded the case to the FERC in April 2009.

On October 3, 2011, the FERC issued an Order on Remand, finding that, in light of the Ninth Circuit s remand order, additional procedures are needed to address possible unlawful activity that may have influenced prices in the Pacific Northwest spot market during the period from December 25, 2000 through June 20, 2001. The Order establishes an evidentiary, trial-type hearing before an ALJ, and reopens the record to permit parties to present evidence of unlawful market activity during the relevant period. The Order also allows participants to supplement the record with additional evidence on CERS transactions in the Pacific Northwest spot market from January 18, 2001 to June 20, 2001. The Order states that parties seeking refunds must submit evidence demonstrating that specific unlawful market activity occurred, and must demonstrate that such activity directly affected 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.

Both Avista Utilities and Avista Energy were buyers and sellers of energy in the Pacific Northwest energy market during the period between December 25, 2000 and June 20, 2001 and, are subject to potential claims in this proceeding, and if refunds are ordered by the FERC with regard to any particular contract, could be liable to make payments. The Company cannot predict the outcome of this proceeding or the amount of any refunds that Avista Utilities or Avista Energy could be ordered to make. Therefore, the Company cannot predict the potential impact the outcome of this matter could ultimately have on the Company s results of operations, financial condition or cash flows.

California Attorney General Complaint (the Lockyer Complaint)

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

In March 2008, the FERC issued an order establishing a trial-type hearing to address whether any individual public utility seller s violation of the FERC s market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period. Purchasers in the California markets were given the opportunity to present evidence that any seller that violated the quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus cause its market-based rates to be unjust and unreasonable. In March 2010, the Presiding Administrative Law Judge (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.

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Based on information currently known to the Company s management, and the ALJ s granting of Avista Utilities and Avista Energy s summary disposition motion, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

Colstrip Generating Project Complaint

In March 2007, two families that own property near the holding ponds from Units 3 & 4 of the Colstrip Generating Project (Colstrip) filed a complaint against the owners of Colstrip and Hydrometrics, Inc. in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs allege that the holding ponds and remediation activities have adversely impacted their property. They allege contamination, decrease in water tables, reduced flow of streams on their property and other similar impacts to their property. They also seek punitive damages, attorney s fees, an order by the court to remove certain ponds, and the forfeiture of profits earned from the generation of Colstrip. In September 2010, the owners of Colstrip filed a motion with the court to enforce a settlement agreement that would resolve all issues between the parties. In October 2011, the court issued an order, which enforces the settlement agreement. The plaintiffs have the opportunity to appeal the court s decision. 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. Based on the court s enforcement of the settlement agreement, the Company does not expect this complaint will have a material adverse effect on its financial condition, results of operations or cash flows.

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), which is expected to be finalized in 2011. The actual cleanup, if any, will not occur until the RI/FS is complete. Based on the review of its records related to Harbor Oil, the Company does not believe it is a major contributor to this potential environmental contamination based on the small volume of waste oil it delivered to the Harbor Oil site. However, there is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred. 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 under one 50-year FERC license issued in June 2009 and are referred to as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. The license incorporated the 4(e) conditions that were included in the December 2008 Settlement Agreement with the United States Department of Interior and the Coeur d Alene Tribe, as well as the mandatory conditions that were agreed to in the Idaho 401 Water Quality Certifications and in the amended Washington 401 Water Quality Certification.

As part of the Settlement Agreement with the Washington Department of Ecology (DOE), the Company participated in the Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On May 20, 2010, the EPA approved the TMDL and on May 27, 2010, the DOE filed an amended 401 Water Quality Certification with the FERC for inclusion into the license. The amended 401 Water Quality Certification includes the Company s level of responsibility, as defined in the TMDL, for low dissolved oxygen levels in Lake Spokane. The Company has until May 27, 2012 to develop mitigation strategies to address the low levels of dissolved oxygen. It is not possible to provide cost estimates at this time because the mitigation measures have not been fully identified or approved by the DOE. 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.

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

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels in the Clark Fork River exceed state of Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during periods when excess river flows must be diverted over the spillway. In 2002, the Company submitted a Gas Supersaturation Control Program (GSCP) to the Idaho Department of Environmental Quality (Idaho DEQ) and U.S. Fish and Wildlife Service (USFWS). This submission was part of the Clark Fork Settlement Agreement for licensing the use of Cabinet Gorge. The GSCP provided for the opening and modification of possibly two diversion tunnels around Cabinet Gorge to allow streamflow to be diverted when flows are in excess of powerhouse capacity. In 2007, engineering studies determined that the tunnels would not sufficiently reduce Total Dissolved Gas (TDG). In consultation with the Idaho DEQ and the USFWS, the Company developed an addendum to the GSCP. The GSCP addendum abandons the concept to reopen the two diversion tunnels and requires the Company to evaluate a variety of different options to abate TDG. In March 2010, the FERC approved the GSCP addendum of preliminary design for alternative abatement measures. In the second quarter of 2011, the Company completed preliminary feasibility assessments for several alternative abatement measures and determined that two alternatives will be considered for continued development. Further analysis and review of these alternatives is expected to be completed through early 2012. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the USFWS listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company is evaluating the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies will help the Company and other parties determine the best use of funds toward continuing fish passage efforts or other bull trout population enhancement measures. In 2009, the Company selected a contractor to design a permanent upstream passage facility at Cabinet Gorge. The Company anticipates that the design and cost estimates will be completed by the end of 2012 with construction taking place in 2013 and 2014.

In January 2010, the USFWS proposed to revise its 2005 designation of critical habitat for the bull trout. The proposed revisions include the lower Clark Fork River as critical habitat. In April 2010, the Company submitted comments recommending the lower Clark Fork River be excluded from critical habitat designation based in part on the bull trout recovery efforts the Company is already undertaking. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to fish passage at Cabinet Gorge and Noxon Rapids.

Aluminum Recycling Site

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

Injury from Overhead Electric Line (Munderloh v. Avista)

On March 4, 2010, the plaintiff and his wife filed a complaint against Avista Corp. in Spokane County Superior Court. Plaintiffs allege that while the plaintiff was employed by a third party as a laborer at their construction site, he came into contact with Avista Corp. s electric line, was injured and suffered economic and non-economic damages. Plaintiffs further allege that Avista Corp. was at fault for failing to relocate the overhead electric line which it controlled and operated adjacent to the construction site. In addition to economic and non-economic damages, plaintiffs also seek other damages, attorney s fees and costs, prejudgment interest and punitive damages. In September 2011, Avista Corp. s Motion for Summary Judgment was denied, and Avista Corp. appealed this decision. Trial has been scheduled to begin in February 2012. The plaintiffs have not yet provided a statement specifying damages. Because the resolution of this claim remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company s liability. However, based on information currently known to the Company s management, the Company does not expect this complaint will have a material adverse effect on its financial condition, results of operations or cash flows.

Damages from Fire in Stevens County, Washington

In August 2010, a fire in Stevens County, Washington occurred during a wind storm. The apparent cause of the fire may be a tree located outside of Avista Corp. s right-of-way that came in contact with an electric line owned by Avista Corp. The fire area is a rural farm and timber landscape. The fire destroyed two residences and six outbuildings. The Company is not aware of any personal injuries resulting from the fire. Although no lawsuits have been filed, Avista Corp. has received several claims and it is possible that additional claims may be made and lawsuits may be filed against the Company. Because the resolution of this issue remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company s liability. However, based on information currently known to the Company s management, the Company does not expect this complaint will have a material adverse 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 adverse impact on its financial condition, results of operations or cash flows. It is possible that a change could occur in the Company s estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant.

NOTE 12. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company s management to analyze performance and determine the allocation of resources. Avista Utilities business is managed based on the total regulated utility operation. Ecova (formerly Advantage IQ) is a provider of energy efficiency and cost management programs and services for multi-site customers throughout North America. The Other category, which is not a reportable segment, includes sheet metal fabrication, venture fund investments and real estate investments, Spokane Energy, as well as certain other operations of Avista Capital.

AVISTA CORPORATION

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

	Avista Utilities	Ecova	Other	Total Non-Utility	Intersegment Eliminations (1)	Total
For the three months ended September 30, 2011:						
Operating revenues	$ 302,001	$ 32,228	$ 9,931	$ 42,159	$ (450)	$ 343,710
Resource costs	171,393					171,393
Other operating expenses	60,579	23,790	8,386	32,176	(450)	92,305
Depreciation and amortization	26,341	1,784	180	1,964		28,305
Income from operations	26,859	6,654	1,365	8,019		34,878
Interest expense (2)	17,639	71	1,150	1,221	(5)	18,855
Income taxes	1,546	2,416	(245)	2,171		3,717
Net income (loss) attributable to Avista Corporation	7,582	3,467	(347)	3,120		10,702
Capital expenditures	69,716	897	233	1,130		70,846
For the three months ended September 30, 2010:						
Operating revenues	$ 331,542	$ 25,568	$ 16,813	$ 42,381	$ (6,751)	$ 367,172
Resource costs	201,113					201,113
Other operating expenses	59,961	18,021	14,592	32,613	(6,751)	85,823
Depreciation and amortization	24,918	1,498	234	1,732		26,650
Income from operations	29,708	6,049	1,987	8,036		37,744
Interest expense (2)	17,708	15	1,348	1,363	(66)	19,005
Income taxes	2,616	2,238	176	2,414		5,030
Net income attributable to Avista Corporation	9,058	2,936	352	3,288		12,346
Capital expenditures	57,798	293	57	350		58,148
For the nine months ended September 30, 2011:						
Operating revenues	$ 1,060,571	$ 91,207	$ 30,425	$121,632	$ (1,350)	$ 1,180,853
Resource costs	575,290					575,290
Other operating expenses	188,961	72,220	24,711	96,931	(1,350)	284,542
Depreciation and amortization	78,600	5,086	587	5,673		84,273
Income from operations	156,199	13,901	5,127	19,028		175,227
Interest expense (2)	52,134	206	3,912	4,118	(382)	55,870
Income taxes	35,857	5,005	75	5,080		40,937
Net income (loss) attributable to Avista Corporation	68,733	7,016	(128)	6,888		75,621
Capital expenditures	169,598	2,173	557	2,730		172,328
For the nine months ended September 30, 2010:						
Operating revenues	$ 1,081,690	$ 74,725	$ 47,337	$122,062	$ (19,432)	$ 1,184,320
Resource costs	628,864					628,864
Other operating expenses	174,044	57,732	41,724	99,456	(19,432)	254,068
Depreciation and amortization	73,890	4,522	780	5,302		79,192
Income from operations	150,013	12,471	4,833	17,304		167,317
Interest expense (2)	53,415	68	4,243	4,311	(188)	57,538
Income taxes	34,243	4,576	(87)	4,489		38,732
Net income (loss) attributable to Avista Corporation	60,898	5,895	(97)	5,798		66,696
Capital expenditures	138,083	994	306	1,300		139,383
Total Assets:						
As of September 30, 2011	$ 3,607,397	$ 246,220	$ 114,969	$ 361,189	$	$ 3,968,586
As of December 31, 2010	$ 3,589,235	$ 221,086	$ 129,774	$ 350,860	$	$ 3,940,095

(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.

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 Corporation) as of September 30, 2011, and the related condensed consolidated statements of income and of comprehensive income for the three-month and nine-month periods ended September 30, 2011 and 2010, and of equity and redeemable noncontrolling interests, and cash flows for the nine-month periods ended September 30, 2011 and 2010. These interim financial statements are the responsibility of the Corporation 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, 2010, 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 25, 2011, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of accounting guidance for variable interest entities. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2010 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP

Seattle, Washington

November 4, 2011

AVISTA CORPORATION

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 (formerly Advantage IQ)** an indirect subsidiary of Avista Corp. (79.2 percent owned as of September 30, 2011) provides energy efficiency and cost management programs and services for multi-site customers and utilities throughout North America. Ecova s primary product lines include expense management services for utility, telecom and lease needs as well as strategic energy management and efficiency services that include procurement, conservation, performance reporting, financial planning and energy efficiency program management for commercial enterprises and utilities.

We have other businesses, including sheet metal fabrication, venture fund investments and real estate investments, Spokane Energy (see Note 3), 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 Advanced Manufacturing and Development (AM&D), doing business as METALfx.

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

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Avista Utilities	$ 7,582	$ 9,058	$ 68,733	$ 60,898
Ecova	3,467	2,936	7,016	5,895
Other	(347)	352	(128)	(97)
Net income attributable to Avista Corporation	$ 10,702	$ 12,346	$ 75,621	$ 66,696

Executive Level Summary

Overall

Net income attributable to Avista Corp. was $10.7 million for the three months ended September 30, 2011, a decrease from $12.3 million for the three months ended September 30, 2010. The decrease in net income was primarily due to lower earnings at Avista Utilities (primarily due to an increase in other operating expenses, depreciation and amortization, and taxes other than income taxes) and a net loss at the other businesses, partially offset by an increase in earnings at Ecova.

Net income attributable to Avista Corp. was $75.6 million for the nine months ended September 30, 2011, an increase from $66.7 million for the nine months ended September 30, 2010. The increase in year-to-date net income was primarily due to an increase in earnings at Avista Utilities (primarily due to colder weather during the heating season, lower power supply costs and the implementation of general rate increases, partially offset by an increase in other operating expenses, depreciation and amortization, and taxes other than income taxes) and partially due to an increase in earnings at Ecova. The first quarter of 2011 was significantly colder than the first quarter of 2010, which was one of the warmest January to March periods on record in our service territory.

Avista Utilities

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

- weather conditions,
- regulatory decisions, allowing our utility to recover costs, including purchased power and fuel costs, on a timely basis, and to earn a reasonable return on investment,
- the price of natural gas in the wholesale market, including the effect on the price of fuel for generation,
- the price of electricity in the wholesale market, including the effects of weather conditions, natural gas prices and other factors affecting supply and demand, and
- the ability to obtain financing through the issuance of debt and/or equity securities, which can be affected by various factors including our credit ratings, interest rates and other capital market conditions.

AVISTA CORPORATION

In our utility operations, we continue to regularly review the need for rate changes in each jurisdiction to improve the recovery of costs and capital investments in our generation, transmission and distribution systems. General rate increases went into effect in Idaho on October 1, 2011 and October 1, 2010, in Washington effective December 1, 2010 and in Oregon effective March 15, 2011 and June 1, 2011. In September 2011, we entered into a settlement agreement in our Washington general rate cases (filed in May 2011) that, if approved by the WUTC, will provide for electric and natural gas rate increases effective January 1, 2012.

Our utility net income was $7.6 million for the three months ended September 30, 2011, a decrease from $9.1 million for the three months ended September 30, 2010. The decrease in utility net income was due to an increase in other operating expenses, depreciation and amortization, and taxes other than income taxes.

Our utility net income was $68.7 million for the nine months ended September 30, 2011, an increase from $60.9 million for the nine months ended September 30, 2010. Earnings for the nine months ended September 30, 2011 were positively impacted by an increase in gross margin (operating revenues less resource costs). The increase in gross margin was primarily due to higher retail loads caused by colder weather during the heating season and power supply costs below the amount included in base retail rates, as well as general rate increases. The increase in gross margin was partially offset by an increase in other operating expenses, depreciation and amortization, and taxes other than income taxes. The increase in other operating expenses was primarily due to increased maintenance expenses (including planned major maintenance at Colstrip), pensions and other postretirement benefits, and labor.

We are continuing to invest in generation, transmission and distribution systems to enhance service reliability for our customers and replace aging infrastructure. Utility capital expenditures were $169.6 million for the nine months ended September 30, 2011. We expect utility capital expenditures to be about $235 million for the full year of 2011. These estimates of capital expenditures are subject to continuing review and adjustment (see discussion at Avista Utilities Capital Expenditures).

Ecova (formerly Advantage IQ)

Ecova had net income attributable to Avista Corp. of $3.5 million for the three months ended September 30, 2011, an increase from $2.9 million for the three months ended September 30, 2010. Ecova had net income attributable to Avista Corp. of $7.0 million for the nine months ended September 30, 2011, an increase from $5.9 million for the nine months ended September 30, 2010. This increase for 2011 as compared to 2010 was primarily due to strong growth in energy management services, moderate growth from expense management, as well as the acquisition of The Loyalton Group (Loyalton) effective December 31, 2010. The acquisition of Loyalton was funded primarily through available cash at Ecova plus contingent consideration based on revenue targets over the next three years. Ecova s earnings potential continues to be moderated by low short-term interest rates, which limits interest revenue on funds held for customers.

The acquisition of Cadence Network in July 2008 was funded with the issuance of Ecova common stock. Under the transaction agreement, the previous owners of Cadence Network can exercise a right to have their shares of Ecova common stock redeemed by Ecova during July 2011 or July 2012 if Ecova is not liquidated through either an initial public offering or sale of the business to a third party. These redemption rights were not exercised in July 2011. Their redemption rights expire July 31, 2012. The redemption price would be determined based on the fair market value of Ecova at the time of the redemption election as determined by certain independent parties. As of September 30, 2011, there were redeemable noncontrolling interests of $39.0 million related to these redemption rights. Should the previous owners of Cadence Network exercise their redemption rights, Ecova will seek the necessary funding through its credit facility, a capital request from existing owners, an infusion of capital from potential new investors or a combination of these sources. In January 2011, Avista Capital purchased shares held by one of the previous owners of Cadence Network for $5.6 million.

We may seek to monetize all or part of our investment in Ecova in the future, regardless of whether Ecova s minority owner redemption rights are exercised. The value of a potential monetization depends on future market conditions, growth of the business and other factors. This may provide access to public market capital and provide potential liquidity to Avista Corp. and the other owners of Ecova. There can be no assurance that such a transaction will be completed.

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 are unable to obtain capital on reasonable terms, it may 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 CORPORATION

In February 2011, we entered into a new committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2015 that replaced our $320.0 million and $75.0 million committed lines of credit that had expiration dates in April 2011. As of September 30, 2011, there were $96.5 million of cash borrowings and $14.9 million in letters of credit outstanding. As of September 30, 2011, we had $288.6 million of available liquidity under our committed line of credit.

In October 2011, we entered into a bond purchase agreement with certain institutional investors in the private placement market for the purpose of issuing $85.0 million of 4.45 percent First Mortgage Bonds due in 2041. The issuance of the bonds will occur at closing in December 2011. The total net proceeds from the sale of the new bonds will be used to repay a portion of the borrowings outstanding under our $400.0 million committed line of credit.

In September 2011, we cash settled interest rate swap contracts (notional amount of $85.0 million) and paid a total of $10.6 million. The interest rate swap contracts were entered during the third quarter of 2011 and were settled in connection with the pricing of $85.0 million of First Mortgage Bonds as described above. Upon settlement of the interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the life of the forecasted interest payments.

Based on current market conditions, we are not planning to remarket $83.7 million of Pollution Control Bonds in 2011. We are currently the holder of the bonds and they may be remarketed in the future.

In the nine months ended September 30, 2011, we issued $21.2 million of common stock, including $15.8 million under a sales agency agreement. As of September 30, 2011, we had 0.4 million shares available to be issued under this agreement.

We expect to issue up to $25 million of common stock in 2011 (including issuances during the first nine months of the year) in order to maintain our capital structure at an appropriate level for our business. After considering the issuances of common stock and $85.0 million of First Mortgage Bonds in the fourth quarter of 2011, 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
- move our earned returns closer to those allowed by regulators.

With regards to the timing and plans for future filings, the assessment of our need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include, but are not limited to, in-service dates of major capital investments and the timing of changes in major revenue and expense items. We filed general rate cases in Washington in May 2011 (with a settlement agreement in September 2011 subject to WUTC approval) and in Idaho in July 2011 (which was settled with new rates effective October 1, 2011). The following is a summary of our authorized rates of return in each jurisdiction:

Jurisdiction and service	Implementation Date	Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
Washington electric and natural gas	December 2010	7.9%	10.2%	46.5%
Idaho electric and natural gas	October 2011	(1)	(1)	(1)
Oregon natural gas	March 2011	8.0%	10.1%	50.0%

(1) The rate adjustment implemented on October 1, 2011 resulting from the Idaho electric and natural gas general rate case settlement did not have a specific authorized rate of return, return on equity or equity level.

Washington General Rate Cases

In November 2010, the WUTC approved an all-party settlement stipulation in our general rate case filed in March 2010. As agreed to in the settlement stipulation, electric rates for Washington customers increased by an average of 7.4 percent, which was designed to increase annual revenues by $29.5 million. Natural gas rates for Washington customers increased by an average of 2.9 percent, which was designed to increase annual revenues by $4.6 million. The new electric and natural gas rates became effective on December 1, 2010.

On September 30, 2011, we entered into a settlement agreement in our electric and natural gas general rate cases that were filed with the WUTC in May 2011. Parties to the settlement agreement include the staff of the WUTC, the Public Counsel Section of the Washington Office of the Attorney General, Northwest Industrial Gas Users, Industrial Customers of Northwest Utilities and The Energy Project. The Northwest Energy Coalition (NWEC), the only party that did not sign the settlement agreement, has indicated that it plans to pursue approval of an electric decoupling mechanism in this case. NWEC has also indicated, however, that it does not oppose other terms of the settlement. This settlement agreement is subject to approval by the WUTC. Hearings are scheduled for November 2011.

As agreed to in the settlement stipulation, base electric rates for our Washington customers would increase by an average of 4.6 percent, which is designed to increase annual revenues by $20.0 million. Base natural gas rates for our Washington customers would increase by an average of 2.4 percent, which is designed to increase annual revenues by $3.75 million. The new electric and natural gas rates would become effective on January 1, 2012.

Our original request filed with the WUTC in May 2011 was for an electric rate increase of 9.1 percent, which was designed to increase annual revenues by $38.3 million. The difference between the original request and the amount in the settlement agreement is due to several factors including a decrease in natural gas fuel costs for our thermal generation plants, removal of the proposed Energy Efficiency Load Adjustment, a reduction in certain operating expenses and adjustments for administrative and general expenses. The original request also included an increase in the common equity ratio from 46.5 percent to 48.04 percent and the return on equity from 10.2 percent to 10.9 percent. No capital structure ratios or cost of capital components were specified in the settlement agreement.

In our May 2011 filing, we also requested to increase natural gas rates by an average of 4.0 percent, which was designed to increase annual revenues by $6.2 million. As part of the settlement agreement, we agreed to not file a general rate case in Washington prior to April 1, 2012.

The settlement agreement also provides 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 would be allowed to defer changes in maintenance costs related to our Coyote Spring 2 natural gas-fired generation plant and our 15 percent ownership interest in Units 3&4 of the Colstrip generation plant. We would compare actual, non-fuel, maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of baseline maintenance expenses used to establish base retail rates, and defer the difference. The deferral would occur annually, with no carrying charge, with deferred costs being amortized over a four-year period, beginning in January of 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.

Idaho General Rate Cases

In September 2010, the IPUC approved a settlement agreement in our general rate case filed in March 2010. The new electric and natural gas rates became effective on October 1, 2010. As agreed to in the settlement, base electric rates for our Idaho customers increased by an average of 9.3 percent, which was designed to increase annual revenues by $21.2 million. Base natural gas rates for our Idaho customers increased by an average of 2.6 percent, which was designed to increase annual revenues by $1.8 million.

The settlement agreement included a rate mitigation plan under which the impact on customers of the new rates is reduced by amortizing $11.1 million ($17.5 million when grossed up for income taxes and other revenue-related items) of previously deferred state income taxes over a two-year period as a credit to customers. While our cash collections from customers are reduced by this amortization during the two-year period, the mitigation plan has no impact on our net income. Retail rates increased on October 1, 2011 and will increase on October 1, 2012 as the previous deferred state income tax balance is amortized.

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

When combined with our other rate adjustments, effective October 1, 2011, electric rates for Idaho customers decreased by 2.4 percent and natural gas rates for Idaho customers decreased by 0.8 percent. Other rate adjustments include the annual Power Cost Adjustment (PCA) and Purchased Gas Adjustment (PGA), as well as the Bonneville Power Administration Residential Exchange credit and Demand-Side Management adjustments, which have no impact on our net income.

Our original request filed with the IPUC was for an electric rate increase of 3.7 percent, which was designed to increase annual revenues by $9.0 million. We also requested to increase natural gas rates by an average of 2.7 percent, which was designed to increase annual revenues by $1.9 million.

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

As previously disclosed, in June 2011, we entered into a 30-year power purchase agreement (PPA) to acquire all of the power produced by a wind project. It is expected that the wind project will have a nameplate capacity of approximately 100 megawatts and produce approximately 40 average megawatts with deliveries beginning in the second half of 2012. Under the terms of the settlement agreement, we will include all of the costs (Idaho portion) associated with the PPA through the PCA mechanism until such costs, subject to prudence review, are reflected in general rates.

The settlement agreement also provides for the deferral of certain generation plant operation and maintenance costs. In order to address the variability in year-to-year operation and maintenance costs, beginning in 2011, we will defer changes in operation and maintenance costs related to the Coyote Spring 2 natural gas-fired generation plant and our 15 percent ownership interest in Units 3&4 of the Colstrip generation plant. We will compare actual, non-fuel, operation and maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of expenses authorized for recovery in base rates in the applicable deferral year, and defer the difference from that currently authorized. The deferral will occur annually, with no carrying charge, with deferred costs being amortized over a three-year period, beginning in January of 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.

Oregon General Rate Cases

In March 2011, the OPUC approved an all-party settlement stipulation in our general rate case that was filed in September 2010. The settlement provides for an overall rate increase of 3.1 percent for our Oregon customers, designed to increase annual revenues by $3.0 million. Part of the rate increase became effective March 15, 2011, with the remaining increase effective June 1, 2011. An additional rate adjustment designed to increase revenues by $0.6 million will occur on June 1, 2012 to recover capital costs associated with certain reinforcement and replacement projects upon a demonstration that such projects are complete and the costs were prudently incurred.

Purchased Gas Adjustments

Effective October 1, 2011, natural gas rates increased 1.0 percent in Idaho. Effective November 1, 2011, natural gas rates increased 1.0 percent in Washington, while decreasing 0.2 percent in Oregon. Effective November 1, 2010, natural gas rates increased 4.6 percent in Washington and 4.3 percent in Idaho, while decreasing 3.2 percent in Oregon. PGAs are designed to pass through changes in natural gas costs to our customers with no change in gross margin (operating revenues less resource costs) or net income. In Oregon, we absorb (gain or loss) 10 percent of the difference between actual and projected gas costs for supply that are not hedged. Total net deferred natural gas costs were a liability of $8.0 million as of September 30, 2011, a decrease from $22.1 million as of December 31, 2010.

Power Cost Deferrals and Recovery Mechanisms

The Energy Recovery Mechanism (ERM) is an accounting method used to track certain differences between actual power supply costs, net of the margin on wholesale sales and sales of fuel, and the amount included in base retail rates for our Washington customers. In the 2010 Washington general rate case settlement, the parties agreed that there would be no deferrals under the ERM in 2010. Deferrals under the ERM resumed in 2011. Total net deferred power costs under the ERM were a liability of $6.2 million as of September 30, 2011.

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

short-term wholesale market prices and sales and purchase volumes,

the level of hydroelectric generation,

the level of thermal generation (including changes in fuel prices), and

retail loads.

AVISTA CORPORATION

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

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
+/- $0 - $4 million	0%	100%
+ between $4 million - $10 million	50%	50%
- between $4 million - $10 million	75%	25%
+/- excess over $10 million	90%	10%

Under the ERM, we make an annual filing on or before April 1 of each year to provide the opportunity for the WUTC staff and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. In 2011, we made our filing indicating that there were not any deferrals under the ERM for 2010. The ERM provides for a 90-day review period for the filing; however, the period may be extended by agreement of the parties or by WUTC order. Additionally, we must make a filing (no sooner than June 2011) to allow all interested parties the opportunity to review the ERM, and make recommendations to the WUTC related to the continuation, modification or elimination of the ERM.

We have a Power Cost Adjustment (PCA) mechanism in Idaho that allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. The October 1 rate adjustments recover or rebate power supply costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a regulatory asset of $0.6 million as of September 30, 2011, compared to $18.3 million as of December 31, 2010.

Natural Gas Transmission

In response to natural gas pipeline incidents (not within our service territory), members of the United States Congress are proposing various additional regulations to address public safety concerns. Regulations have been proposed to require automatic shut-off valves on pipeline mains; increase installation of excess flow valves on gas service piping, increase high consequence area boundaries as well as to provide additional 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.

In addition, the Pipeline and Hazardous Materials Safety Administration issued an Advisory Bulletin in January 2011 to remind operators of gas and hazardous liquid pipeline facilities of their responsibilities, under federal integrity management regulations, to perform detailed threat and risk analyses especially with regards to their pipelines maximum allowable operating pressures. While we believe that we operate our pipeline systems in a safe manner, we cannot predict the impact of any future regulations or inspections of our natural gas system.

<u>Results of Operations</u>

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

Three months ended September 30, 2011 compared to the three months ended September 30, 2010

Utility revenues decreased $29.5 million, after elimination of intracompany revenues of $30.9 million. Including intracompany revenues, electric revenues increased $2.4 million and natural gas revenues decreased $1.1 million. Retail electric revenues increased $12.5 million primarily due to general rate increases. In addition, sales of fuel increased $16.1 million (reflecting lower usage of our thermal generating plants and sales of natural gas fuel not used in generation). These increases in electric revenues were partially offset by a decrease in wholesale electric revenues of $26.0 million (due to a decrease in wholesale prices and volumes). Changes in natural gas revenues were not significant to the Condensed Consolidated Statements of Income.

Non-utility revenues increased $6.1 million to $42.2 million primarily as a result of Ecova s revenues increasing $6.7 million due to moderate growth in expense management and energy management services, as well as the acquisition of Loyalton effective December 31, 2010. Revenues from our other businesses decreased $0.6 million (excluding intercompany revenues).

Utility resource costs decreased $29.7 million, after elimination of intracompany resource costs of $30.9 million. Including intracompany resource costs, electric resource costs increased $2.8 million and natural gas resource costs decreased $1.6 million. The increase in electric resource costs was primarily due to an increase in other fuel costs (reflecting an increase in thermal generation optimization and lower usage of our thermal plants) and the amortization of deferred power supply costs, partially offset by a decrease in fuel costs (due to lower thermal generation) and power purchased (due in part to higher hydroelectric generation).

Utility depreciation and amortization increased $1.4 million driven by additions to utility plant.

Utility taxes other than income taxes increased $1.0 million primarily reflecting higher retail revenue related taxes, as well as increased property taxes.

Non-utility other operating expenses increased $5.9 million primarily reflecting an increase of $5.8 million for Ecova reflecting increased costs necessary for current and future business growth and the acquisition of Loyalton.

Other expense-net increased $0.8 million primarily due to an increase in net losses on investments, which were $0.6 million in 2011 compared to $0.1 million in 2010. The increase was also partially due to a decrease in equity-related AFUDC.

Income taxes decreased $1.3 million and our effective tax rate was 24.2 percent for the third quarter of 2011 compared to 27.4 percent for the third quarter of 2010. The decrease in income tax expense was primarily due to a decrease in income before income taxes. In the third quarter of 2011, we increased our estimate of pension plan contributions for 2012 (which is tax deductible in the 2011 tax year). This change in estimate reduced income tax expense through September 30, 2011 by $1.8 million representing the portion of the difference between pension costs recorded in the financial statements and the tax deductible cash contributions allocated to capital expenditures. Without this change in estimate, our effective tax rate would have been 36.0 percent for the three months ended September 30, 2011. Adjustments associated with reconciling the 2009 federal income tax return to the amount included in the financial statements for 2009 and prior year income tax return amendments decreased income tax expense by $1.7 million for the three months ended September 30, 2010.

Nine months ended September 30, 2011 compared to the nine months ended September 30, 2010

Utility revenues decreased $21.1 million, after elimination of intracompany revenues of $71.7 million. Including intracompany revenues, electric revenues increased $26.0 million and natural gas revenues increased $24.5 million. Retail electric revenues increased $50.6 million due to general rate increases and an increase in volumes caused by colder weather in the heating season. In addition, sales of fuel increased $51.2 million (reflecting lower usage of our thermal generating plants and sales of natural gas fuel not used in generation). These increases in electric revenues were partially offset by a decrease in wholesale electric revenues of $76.5 million (due to a decrease in wholesale prices and volumes). Retail natural gas revenues increased $35.0 million due to an increase in volumes caused by colder weather and prices from rate increases, while wholesale natural gas revenues decreased $9.4 million.

Non-utility revenues increased $17.7 million to $121.6 million primarily as a result of Ecova s revenues increasing $16.5 million due to moderate growth in expense management and energy management services, as well as the acquisition of Loyalton effective December 31, 2010. Revenues from our other businesses increased $1.2 million (excluding intercompany revenues) primarily due to increased sales at METALfx.

Utility resource costs decreased $53.6 million, after elimination of intracompany resource costs of $71.7 million. Including intracompany resource costs, electric resource costs increased $9.4 million and natural gas resource costs increased $8.7 million. The increase in electric resource costs was primarily due to an increase in other fuel costs (reflecting an increase in thermal generation optimization and lower usage of our thermal plants) and the amortization of deferred power supply costs, partially offset by a decrease in fuel costs (due to lower thermal generation) and power purchased (due in part to higher hydroelectric generation). The increase in natural gas resource costs was primarily due to an increase in natural gas purchased due to an increase in retail sales.

Utility other operating expenses increased $14.9 million primarily due to increased maintenance expenses (including planned major maintenance at Colstrip), pensions and other postretirement benefits, and labor.

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

Utility taxes other than income taxes increased $6.6 million primarily reflecting higher retail revenue related taxes, as well as increased property taxes.

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Non-utility other operating expenses increased $15.6 million primarily reflecting an increase of $14.5 million for Ecova reflecting increased costs necessary for current and future business growth and the acquisition of Loyalton.

Interest expense decreased $1.6 million primarily due to refinancing transactions completed in December 2010 that lowered our effective rate on long-term debt. This was partially offset by higher interest rates on short-term borrowings.

Income taxes increased $2.2 million and our effective tax rate was 34.5 percent for the nine months ended September 30, 2011 compared to 36.1 percent for the nine months ended September 30, 2010. This increase in expense was primarily due to an increase in income before income taxes. In the third quarter of 2011, we increased our estimate of pension plan contributions for 2012 (which is tax deductible in the 2011 tax year). This change in estimate reduced income tax expense through September 30, 2011 by $1.8 million representing the portion of the difference between pension costs recorded in the financial statements and the tax deductible cash contributions allocated to capital expenditures. Adjustments associated with reconciling the 2009 federal income tax return to the amount included in the financial statements for 2009 and prior year income tax return amendments decreased income tax expense by $1.7 million for the nine months ended September 30, 2010.

Avista Utilities

Three months ended September 30, 2011 compared to the three months ended September 30, 2010

Net income for Avista Utilities was $7.6 million for the three months ended September 30, 2011, a decrease from $9.1 million for the three months ended September 30, 2010. Avista Utilities income from operations was $26.9 million for the three months ended September 30, 2011 compared to $29.7 million for the three months ended September 30, 2010. The decrease in net income and income from operations was primarily due to an increase in other operating expenses, depreciation and amortization, and taxes other than income taxes.

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

	Electric		Natural Gas		Intracompany		Total	
	2011	2010	2011	2010	2011	2010	2011	2010
Operating revenues	$ 248,592	$ 246,198	$ 84,277	$ 85,344	$ (30,868)	$	$ 302,001	$ 331,542
Resource costs	134,277	131,504	67,984	69,609	(30,868)		171,393	201,113
Gross margin	$ 114,315	$ 114,694	$ 16,293	$ 15,735	$	$	$ 130,608	$ 130,429

Avista Utilities operating revenues decreased $29.5 million and resource costs decreased $29.7 million, which resulted in an increase of $0.2 million in gross margin. The gross margin on electric sales decreased $0.4 million and the gross margin on natural gas sales increased $0.6 million. For the three months ended September 30, 2011, we recognized a benefit of $1.0 million under the ERM in Washington. For the three months ended September 30, 2010, power supply costs were $3.8 million below the level included in base retail rates in Washington.

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). The magnitude of these transactions in prior years was immaterial, but increased significantly in 2010 with the addition of the natural gas-fired Lancaster Plant to our electric resource mix. All transactions for 2010 were recorded in the fourth quarter of 2010. These transactions are eliminated in the presentation of Avista Utilities total results and in the consolidated financial statements.

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

	Electric Operating Revenues		Electric Energy MWh sales	
	2011	2010	2011	2010
Residential	$ 66,437	$ 61,176	758	764
Commercial	73,264	68,658	825	822
Industrial	32,847	30,292	567	555
Public street and highway lighting	1,728	1,653	6	6
Total retail	174,276	161,779	2,156	2,147
Wholesale	21,455	47,478	752	984
Sales of fuel	46,366	30,254		
Other	6,495	6,687		
Total	$ 248,592	$ 246,198	2,908	3,131

Retail electric revenues increased $12.5 million due to an increase in total MWhs sold (increased revenues $0.7 million) and an increase in revenue per MWh (increased revenues $11.8 million). The increase in revenue per MWh was primarily due to the Washington and Idaho general rate increases.

Wholesale electric revenues decreased $26.0 million due to a decrease in sales prices (decreased revenues $19.4 million) and a decrease in sales volumes (decreased revenues $6.6 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 as sales of fuel. These revenues increased $16.1 million due to an increase in sales of natural gas fuel as part of thermal generation resource optimization and lower usage of our thermal generation plants in 2011 as compared to 2010. This was due in part to increased hydroelectric generation. In the third quarter of 2011, $14.7 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs.

The net margin on wholesale sales and sales of fuel is applied to reduce or increase resource costs as accounted for under the ERM, the PCA mechanism, and in general rate cases as part of base power supply costs.

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

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2011	2010	2011	2010
Residential	$ 17,353	$ 17,624	12,712	13,877
Commercial	10,506	10,752	10,931	11,732
Interruptible	458	513	823	828
Industrial	900	878	1,162	1,158
Total retail	29,217	29,767	25,628	27,595
Wholesale	52,001	51,877	149,833	134,619
Transportation	1,473	1,367	31,874	29,589
Other	1,586	2,333	14	18
Total	$ 84,277	$ 85,344	207,349	191,821

Retail natural gas revenues decreased $0.6 million due to a decrease in volumes (decreased revenues $2.3 million), partially offset by higher retail rates (increased revenues $1.7 million). We sold less retail natural gas in the third quarter of 2011 as compared to third quarter of 2010 primarily due to warmer weather (particularly in September). The increase in retail rates reflects purchased gas adjustments, as well as general rate increases.

Wholesale natural gas revenues increased $0.1 million. Wholesale sales reflect the sale of natural gas in excess of load requirements as part of the natural gas procurement and resource optimization process. Additionally, we engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas. In the third quarter of 2011, $16.1 million of these sales were made to our electric generation operations and are reflected as intracompany revenues and resource costs. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.

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

	Electric Customers		Natural Gas Customers	
	2011	2010	2011	2010
Residential	316,106	314,858	283,381	281,958
Commercial	39,608	39,459	33,406	33,351
Interruptible			41	39
Industrial	1,387	1,380	259	254
Public street and highway lighting	456	449		
Total retail customers	357,557	356,146	317,087	315,602

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

	2011	2010
Electric resource costs:		
Power purchased	$ 39,783	$ 45,860
Power cost amortizations, net	10,842	(762)
Fuel for generation	25,156	40,347
Other fuel costs	49,778	33,000
Other regulatory amortizations, net	4,001	5,207
Other electric resource costs	4,717	7,852
Total electric resource costs	134,277	131,504

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	2011	2010
Natural gas resource costs:		
Natural gas purchased	$ 72,580	$ 68,432
Natural gas cost amortizations, net	(5,369)	(107)
Other regulatory amortizations, net	773	1,284
Total natural gas resource costs	67,984	69,609
Intracompany resource costs	(30,868)	
Total resource costs	$ 171,393	$ 201,113

Power purchased decreased $6.1 million due to a decrease in the volume of power purchases (decreased costs $17.9 million), partially offset by an increase in wholesale prices (increased costs $11.8 million). The decrease in the volume of the power purchases was due in part to an increase in hydroelectric generation.

Net amortization of deferred power costs was $10.8 million for the third quarter of 2011 compared to net deferrals of $0.8 million for the third quarter of 2010. During the third quarter of 2011, we recovered (collected as revenue) $4.3 million of previously deferred power costs in Idaho through the PCA surcharge. The Washington ERM surcharge was eliminated in February 2010, since the previous balance of deferred power costs had been recovered. During the third quarter of 2011 actual power supply costs were below the amount included in base retail rates in both Washington and Idaho. As such, we deferred $2.6 million in Idaho and $4.0 million in Washington for potential future rebate to customers.

Fuel for generation decreased $15.2 million primarily due to a decrease in thermal generation. This was due in part to an increase in hydroelectric generation.

Other fuel costs increased $16.8 million. This represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation as part of the resource optimization process. The associated revenues are reflected as sales of fuel.

The expense for natural gas purchased increased $4.1 million primarily due to an increase in the price of natural gas. During the third quarter of 2011, natural gas resource costs were reduced by $5.4 million reflecting the rebate of a deferred liability for natural gas costs through the purchased gas adjustments.

Nine months ended September 30, 2011 compared to the nine months ended September 30, 2010

Net income for Avista Utilities was $68.7 million for the nine months ended September 30, 2011, an increase from $60.9 million for the nine months ended September 30, 2010. Avista Utilities income from operations was $156.2 million for the nine months ended September 30, 2011 compared to $150.0 million for the nine months ended September 30, 2010. The increase in net income and income from operations was primarily due to an increase in gross margin (operating revenues less resource costs), partially offset by an increase in other operating expenses, depreciation and amortization, and taxes other than income taxes.

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

	Electric		Natural Gas		Intracompany		Total	
	2011	2010	2011	2010	2011	2010	2011	2010
Operating revenues	$ 746,821	$ 720,811	$ 385,410	$ 360,879	$ (71,660)	$	$ 1,060,571	$ 1,081,690
Resource costs	362,935	353,549	284,015	275,315	(71,660)		575,290	628,864

Gross margin	$ 383,886	$ 367,262	$ 101,395	$ 85,564	$	$	$ 485,281	$ 452,826

Avista Utilities operating revenues decreased $21.1 million and resource costs decreased $53.6 million, which resulted in an increase of $32.5 million in gross margin. The gross margin on electric sales increased $16.6 million and the gross margin on natural gas sales increased $15.8 million. The increase in electric gross margin was due to colder weather during the heating season that increased retail loads, power supply costs below the amount included in base retail rates (due to improved hydroelectric generation and lower purchased power and fuel costs) and general rate increases. For the nine months ended September 30, 2011, we recognized a benefit of $5.7 million under the ERM in Washington. For the nine months ended September 30, 2010, power supply costs were $1.0 million below the level included in base retail rates in Washington. The increase in our natural gas gross margin was primarily due to colder weather that increased retail loads and partially due to general rate increases.

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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). The magnitude of these transactions in prior years was immaterial, but increased significantly in 2010 with the addition of the natural gas-fired Lancaster Plant to our electric resource mix. All transactions for 2010 were recorded in the fourth quarter of 2010. These transactions are eliminated in the presentation of Avista Utilities total results and in the consolidated financial statements.

The following table presents our utility electric operating revenues and megawatt-hour (MWh) sales for the nine months ended September 30 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2011	2010	2011	2010
Residential	$ 236,818	$ 208,599	2,699	2,572
Commercial	209,452	195,327	2,331	2,293
Industrial	92,896	84,841	1,615	1,564
Public street and highway lighting	5,200	5,025	19	19
Total retail	544,366	493,792	6,664	6,448
Wholesale	55,197	131,679	2,121	2,950
Sales of fuel	131,359	80,181		
Other	15,899	15,159		
Total	$ 746,821	$ 720,811	8,785	9,398

Retail electric revenues increased $50.6 million due to an increase in total MWhs sold (increased revenues $17.7 million) primarily due to an increase in use per customer as a result of colder weather, and an increase in revenue per MWh (increased revenues $32.9 million). Compared to 2010, residential electric use per customer increased 4 percent and commercial use per customer increased 1 percent. The increase in revenue per MWh was primarily due to the Washington and Idaho general rate increases.

Wholesale electric revenues decreased $76.5 million due to a decrease in sales prices (decreased revenues $54.9 million) and a decrease in sales volumes (decreased revenues $21.6 million). The decrease in sales volumes was primarily due to decreased wholesale power optimization and higher than expected retail sales caused by colder weather in the heating season.

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 as sales of fuel. These revenues increased $51.2 million due to an increase in sales of natural gas fuel as part of thermal generation resource optimization and lower usage of our thermal generation plants in 2011 as compared to 2010. This was due in part to increased hydroelectric generation. In the nine months ended September 30, 2011, $27.6 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs.

The net margin on wholesale sales and sales of fuel is applied to reduce or increase resource costs as accounted for under the ERM, the PCA mechanism, and in general rate cases as part of base power supply costs.

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

	Natural Gas Operating Revenues	Natural Gas Therms Delivered

	2011	2010	2011	2010
Residential	$ 145,138	$ 122,659	134,502	118,461
Commercial	75,427	63,111	83,316	72,453
Interruptible	1,885	2,008	3,321	3,197
Industrial	3,243	2,888	4,212	3,949
Total retail	225,693	190,666	225,351	198,060
Wholesale	149,039	158,453	389,352	372,522
Transportation	4,914	4,686	111,996	102,068
Other	5,764	7,074	347	299
Total	$ 385,410	$ 360,879	727,046	672,949

Retail natural gas revenues increased $35.0 million due to an increase in volumes (increased revenues $27.3 million) and higher retail rates (increased revenues $7.7 million). We sold more retail natural gas in 2011 as compared to 2010 primarily due to colder weather in the heating season. Compared to 2010, residential natural gas use per customer increased 13 percent and commercial use per customer increased 15 percent. The increase in retail rates reflects purchased gas adjustments, as well as general rate increases.

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Wholesale natural gas revenues decreased $9.4 million due to a decrease in prices (decreased revenues $15.8 million), partially offset by an increase in volumes (increased revenues $6.4 million). Wholesale sales reflect the sale of natural gas in excess of load requirements as part of the natural gas procurement and resource optimization process. Additionally, we engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas. In the nine months ended September 30, 2011, $44.0 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.

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

	Electric Customers		Natural Gas Customers	
	2011	2010	2011	2010
Residential	316,402	314,762	284,238	282,337
Commercial	39,580	39,470	33,527	33,427
Interruptible			37	38
Industrial	1,375	1,376	254	253
Public street and highway lighting	454	448		
Total retail customers	357,811	356,056	318,056	316,055

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

	2011	2010
Electric resource costs:		
Power purchased	$ 123,580	$ 134,810
Power cost amortizations, net	23,886	(1,901)
Fuel for generation	53,999	106,639
Other fuel costs	136,303	85,146
Other regulatory amortizations, net	11,686	14,784
Other electric resource costs	13,481	14,071
Total electric resource costs	362,935	353,549
Natural gas resource costs:		
Natural gas purchased	289,157	282,439
Natural gas cost amortizations, net	(14,264)	(14,902)
Other regulatory amortizations, net	9,122	7,778
Total natural gas resource costs	284,015	275,315
Intracompany resource costs	(71,660)	
Total resource costs	$ 575,290	$ 628,864

Power purchased decreased $11.2 million due to a decrease in the volume of power purchases (decreased costs $25.7 million), partially offset by an increase in wholesale prices (increased costs $14.5 million). The decrease in the volume of the power purchases was due in part to an increase in hydroelectric generation.

Net amortization of deferred power costs was $23.9 million for the nine months ended September 30, 2011 compared to $1.9 million of net deferrals for the nine months ended September 30, 2010. During the nine months ended September 30, 2011, we recovered (collected as revenue) $13.7 million of previously deferred power costs in Idaho through the PCA surcharge. The Washington ERM surcharge was eliminated in February 2010, since the previous balance of deferred power costs had been recovered. During the nine months ended September 30, 2011 actual power supply costs were below the amount included in base retail rates in both Washington and Idaho. This was due to improved hydroelectric generation and lower purchased power and fuel costs. As such, we deferred $4.1 million in Idaho and $6.1 million in Washington for potential future rebate to customers.

Fuel for generation decreased $52.6 million primarily due to a decrease in thermal generation. This was due in part to an increase in hydroelectric generation.

Other fuel costs increased $51.2 million. This represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation as part of the resource optimization process. The associated revenues are reflected as sales of fuel.

The expense for natural gas purchased increased $6.7 million due to an increase in total therms purchased (increased costs $20.7 million), partially offset by a decrease in the price of natural gas (decreased costs $14.0 million). Total therms purchased increased due to an increase in retail loads (resulting from colder weather in the heating season) and an increase in wholesale sales with the balancing of loads and resources as part of the natural gas procurement process. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas. During the nine months ended September 30, 2011, natural gas resource costs were reduced by $14.3 million reflecting the rebate of a deferred liability for natural gas costs through the purchased gas adjustments.

Ecova (formerly Advantage IQ)

Three months ended September 30, 2011 compared to the three months ended September 30, 2010

Ecova s net income attributable to Avista Corp. was $3.5 million for the three months ended September 30, 2011 compared to $2.9 million for the three months ended September 30, 2010. Operating revenues increased $6.7 million and total operating expenses increased $6.1 million. The increase in net income attributable to Avista Corp. and operating revenues was primarily due to strong growth in energy management services, moderate growth in expense management, as well as the acquisition of Loyalton effective December 31, 2010. The increase in operating expenses primarily reflects increased costs necessary for current and future business growth and the acquisition of Loyalton. In the third quarter of 2011, we recorded an adjustment for state sales taxes, which had a positive impact on net income of $0.7 million. Results for the third quarter of 2010 were positively impacted $0.5 million for a business and occupation tax refund. As of September 30, 2011, Ecova had 533 customers representing 369,000 billed sites in North America. In the three months ended September 30, 2011, Ecova managed bills totaling $4.8 billion, a decrease of $60 million, or 1 percent, as compared to the three months ended September 30, 2010.

Nine months ended September 30, 2011 compared to the nine months ended September 30, 2010

Ecova s net income attributable to Avista Corp. was $7.0 million for the nine months ended September 30, 2011 compared to $5.9 million for the nine months ended September 30, 2010. Operating revenues increased $16.5 million and total operating expenses increased $15.1 million. The increase in net income attributable to Avista Corp. and operating revenues was primarily due to strong growth in energy management services, moderate growth in expense management, as well as the acquisition of Loyalton effective December 31, 2010. The increase in operating expenses primarily reflects increased costs necessary for current and future business growth and the acquisition of Loyalton. In the nine months ended September 30, 2011, Ecova managed bills totaling $14.2 billion, an increase of $1.1 billion, or 8 percent, as compared to the nine months ended September 30, 2010. The increase was due to an increase in both the average value of each bill processed and the number of accounts managed.

Other Businesses

Three months ended September 30, 2011 compared to the three months ended September 30, 2010

The net loss from these operations was $0.3 million for the three months ended September 30, 2011 compared to net income of $0.4 million for the three months ended September 30, 2010. Operating revenues decreased $6.9 million and total operating expenses decreased $6.3 million. The decrease in operating revenues and operating expenses was primarily due to the assignment of the Lancaster power purchase agreement (PPA) to Avista Corp. in December 2010. The net loss for the third quarter of 2011 was primarily due to losses on investments of $0.6 million compared to losses of $0.1 million for the third quarter of 2010.

Nine months ended September 30, 2011 compared to the nine months ended September 30, 2010

The net loss from these operations was $0.1 million for the nine months ended September 30, 2011 and 2010. Operating revenues decreased $16.9 million and total operating expenses decreased $17.2 million. The decrease in operating revenues and operating expenses was primarily due to the assignment of the Lancaster PPA to Avista Corp. in December 2010. Earnings from METALfx increased to $1.1 million for the nine months ended September 30, 2011 compared to $0.6 million for the nine months ended September 30, 2010. Losses on investments were $0.6 million for 2011 compared to losses of $0.8 million for 2010.

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 2010 Form 10-K and have not changed materially from that discussion.

AVISTA CORPORATION

Liquidity and Capital Resources

Review of Cash Flow Statement

Overall During the nine months ended September 30, 2011, positive cash flows from operating activities of $240.4 million were used to fund the majority of our cash requirements. These cash requirements included utility capital expenditures of $169.6 million and dividends of $47.7 million. We were also able to reduce short-term borrowings by $13.5 million.

Operating Activities Net cash provided by operating activities was $240.4 million for the nine months ended September 30, 2011 compared to $201.7 million for the nine months ended September 30, 2010. Net cash provided by working capital components was $29.8 million for the nine months ended September 30, 2011, compared to $42.8 million for the nine months ended September 30, 2010. The net cash provided during the nine months ended September 30, 2011 primarily reflects positive cash flows from accounts receivable (representing a seasonal decrease in receivables outstanding). These positive cash flows were partially offset by net cash outflows related to an increase in natural gas stored, other current assets (primarily representing an increase in income taxes receivable) and accounts payable (primarily related to a seasonal decrease in accounts payable for natural gas purchases and power purchased).

The net cash provided during the nine months ended September 30, 2010 primarily reflected positive cash flows from:

- accounts receivable (representing a seasonal decrease in receivables outstanding), and
- other current assets (primarily representing a decrease in income taxes receivable).

These positive cash flows were partially offset by net cash outflows from accounts payable (primarily related to a seasonal decrease in accounts payable for natural gas purchases and power purchased), an increase in natural gas stored and an increase in construction materials and supplies.

Net amortization of deferred power and natural gas costs was $9.5 million for the nine months ended September 30, 2011 compared to net deferrals of $16.8 million for the nine months ended September 30, 2010. The provision for deferred income taxes was $30.8 million for the nine months ended September 30, 2011 compared to $10.5 million for the nine months ended September 30, 2010. Contributions to our defined benefit pension plan were $26.0 million for the nine months ended September 30, 2011 compared to $21.0 million for the nine months ended September 30, 2010. Cash paid for interest decreased to $41.6 million for the nine months ended September 30, 2011, compared to $45.0 million for the nine months ended September 30, 2010.

Investing Activities Net cash used in investing activities was $167.7 million for the nine months ended September 30, 2011, an increase compared to $152.4 million for the nine months ended September 30, 2010. Utility property capital expenditures increased for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. Beginning in the third quarter of 2011, a portion of Ecova s funds held for customers are held as securities available for sale (purchases of $47.3 million). The remaining funds held for customers are in money market funds.

Financing Activities Net cash used in financing activities was $64.0 million for the nine months ended September 30, 2011 compared to $29.7 million for the nine months ended September 30, 2010. During the nine months ended September 30, 2011, our short-term borrowings decreased $13.5 million. Cash dividends paid increased to $47.7 million (or 82.5 cents per share) for the nine months ended September 30, 2011 from $41.4 million (or 75 cents per share) for the nine months ended September 30, 2010. We issued $21.2 million of common stock during the nine months ended September 30, 2011, including $15.8 million under a sales agency agreement. In September 2011, we cash settled interest rate swap agreements for $10.6 million related to the pricing of $85.0 million of long-term debt (the issuance will occur in December 2011).

During the nine months ended September 30, 2010, our short-term borrowings decreased $12.0 million. We issued $34.7 million of common stock during the nine months ended September 30, 2010, including $33.3 million under a sales agency agreement.

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.

AVISTA CORPORATION

We design operating and capital budgets to control operating costs and optimize capital expenditures, 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.

Over time, our operating cash flows usually do not fully support the amount required for utility capital expenditures. As such, from time to time, we need to access 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 move our earned returns closer to those 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 (either due to 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 increasing energy commodity prices and other increased operating costs for our utility operations. We believe that we have adequate liquidity to meet the increased cash needs of higher energy commodity prices and other increased operating costs through our $400.0 million committed line of credit.

As of September 30, 2011, we had $288.6 million of available liquidity under our committed line of credit. With our $400.0 million credit facility that expires in February 2015, 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 will increase, which will negatively affect our cash flow and liquidity until such costs, with interest, are recovered from customers.

Credit and Nonperformance Risk

Our contracts for the purchase and sale of energy commodities can require collateral in the form of cash or letters of credit. Price movements and/or a downgrade in our credit ratings may 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 and energy prices decreased by 15 percent in the first year and 20 percent in subsequent years, we estimate, based on our positions outstanding at September 30, 2011, that we would potentially be required to post additional collateral of up to $128 million. The additional collateral amount is higher than the amount disclosed in Note 5 of the Notes to Condensed Consolidated Financial Statements because this analysis includes contracts that are not considered derivatives and due to the assumptions about potential energy price changes.

Under the terms of interest rate swap agreements that we enter into periodically, we may be required to post cash collateral depending on fluctuations in the fair value of the instrument. This has not historically been significant to our liquidity position. As of September 30, 2011, we had interest rate swap agreements outstanding with a notional amount totaling $160 million and we had posted collateral of $0.3 million (in the form of a letter of credit). If our credit ratings were lowered to below investment grade based on our interest rate swap agreements outstanding at September 30, 2011, we would potentially be required to post additional collateral of up to $5.1 million.

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 the users of such swaps, that previously had been largely exempted from regulation.

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

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Under the Dodd-Frank Act, Swap Dealers and Major Swap Participants generally will be required to collect minimum initial and variation margin from their counterparties for non-cleared swaps. However the requirement varies with the type of counterparty and the regulator of the Major Swap Participant or Swap Dealer. Avista Corp. should be categorized as a counterparty that is a non-financial end user for the purposes of Dodd-Frank, i.e., as a non-financial entity that engages in derivatives to hedge commercial risk. Under a proposed rule issued by the CFTC, swap dealers and major swap participants subject to regulation by the CFTC would not be required to collect initial or variation margin from counterparties that are non-financial end users. The SEC has not yet issued a proposed rule with respect to security-based swap dealers or security-based major swap participants. However, notwithstanding levels of margin required by regulation (or the lack thereof), concern remains that swap dealer and major swap participant counterparties will pass along their increased capital and interdealer margin costs through higher prices and reductions in thresholds for posting.

The Dodd-Frank Act also requires swaps to be cleared and traded on exchanges or swap execution facilities. Such clearing requirements would result in a significant change from our current practice of bilaterally negotiated credit terms. An exemption to mandatory clearing is available under Dodd-Frank for counterparties that are non-financial end users; however, the cost of entering into a non-cleared swap that is available as a cleared swap may be greater.

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

Capital Resources

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings, and excluding noncontrolling interests, consisted of the following as of September 30, 2011 and December 31, 2010 (dollars in thousands):

	September 30, 2011		December 31, 2010	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 7,370	0.3%	$ 358	%
Current portion of nonrecourse long-term debt	13,357	0.5	12,463	0.5
Short-term borrowings	96,500	3.9	110,000	4.5
Long-term debt to affiliated trusts	51,547	2.1	51,547	2.1
Nonrecourse long-term debt	36,319	1.5	46,471	1.9
Long-term debt	1,084,661	44.1	1,101,499	45.0
Total debt	1,289,754	52.4	1,322,338	54.0
Total Avista Corporation stockholders equity	1,170,918	47.6	1,125,784	46.0
Total	$ 2,460,672	100.0%	$ 2,448,122	100.0%

We need to finance capital expenditures and additional funds for operations from time to time. The cash requirements needed to service our indebtedness, both short-term and long-term, reduces the amount of cash flow available to fund capital expenditures, purchased power, fuel and natural gas costs, dividends and other requirements. Our stockholders equity increased $45.1 million during the nine months ended September 30, 2011 primarily due to net income and the issuance of common stock, partially offset by dividends.

In October 2011, we entered into a bond purchase agreement with certain institutional investors in the private placement market for the purpose of issuing $85.0 million of 4.45 percent First Mortgage Bonds due in 2041. The issuance of the bonds will occur at closing in December 2011. The total net proceeds from the sale of the new bonds will be used to repay a portion of the borrowings outstanding under our $400.0 million committed line of credit.

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 and the $85.0 million debt issuance are expected to be the primary sources of funds for operating needs, dividends and capital expenditures for the fourth quarter of 2011. Borrowings under our $400.0 million committed line of credit will supplement these funds to the extent necessary.

We are planning to issue up to $25 million of common stock in 2011 (including issuances during the first nine months of the year) in order to maintain our capital structure at an appropriate level for our business. In the nine months ended September 30, 2011, we issued $21.2 million of common stock, including $15.8 million under a sales agency agreement. As of September 30, 2011, we had 0.4 million shares available to be issued under this agreement.

In February 2011, we entered into a new committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2015 that replaced our $320.0 million and $75.0 million committed lines of credit that had expiration dates in April 2011.

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Our committed line of credit agreement contains customary covenants and default provisions, including a covenant which does not permit our ratio of consolidated total debt to consolidated total capitalization to be greater than 65 percent at any time. As of September 30, 2011, we were in compliance with this covenant with a ratio of 52.4 percent.

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

	2011	2010
Balance outstanding at end of period	$ 96,500	$ 75,000
Letters of credit outstanding at end of period	$ 14,883	$ 34,533
Maximum balance outstanding during the period	$ 110,000	$ 100,000
Average balance outstanding during the period	$ 68,934	$ 71,223
Average interest rate during the period	1.38%	0.61%
Average interest rate at end of period	1.54%	0.56%

Any default on the line of credit or other financing arrangements of Avista Corp. or any of our significant subsidiaries could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Any defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock. Avista Corp. does not guarantee the indebtedness of any of its subsidiaries. As of September 30, 2011, Avista Corp. and its subsidiaries were in compliance with all of the covenants of their financing agreements.

Avista Utilities Capital Expenditures

We expect utility capital expenditures to be $235 million for 2011, and $250 million for each of 2012 and 2013. These estimates of capital expenditures are subject to continuing review and adjustment. Actual capital expenditures may vary from our estimates due to factors such as changes in business conditions, construction schedules and environmental requirements.

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

Ecova (formerly Advantage IQ) Credit Agreement

In April 2011, Ecova entered into a new $40.0 million three-year committed line of credit agreement with a financial institution that replaced its $15.0 million committed credit agreement that had an expiration date of May 2011. The credit agreement is secured by substantially all of Ecova s assets. There were no borrowings outstanding under Ecova s credit agreements as of September 30, 2011 and December 31, 2010.

Ecova Redeemable Stock

In 2007, Ecova amended its employee stock incentive plan to provide an annual window at which time holders of common stock can put their shares back to Ecova providing the shares are held for a minimum of six months. Stock is reacquired at fair market value at the date of reacquisition. As the repurchase feature is at the discretion of the minority shareholders and option holders, there were redeemable noncontrolling interests of $13.0 million as of September 30, 2011 for the intrinsic value of stock options outstanding, as well as outstanding redeemable stock. In 2009, the Ecova employee stock incentive plan was amended such that, on a prospective basis, not all options granted under the plan have the put right. Additionally, there were redeemable noncontrolling interests of $39.0 million related to the Cadence Network acquisition, as the previous owners can exercise a right to put their stock back to Ecova in July 2011 or July 2012 if Ecova is not liquidated through either an initial public offering or sale of the business to a third party. These redemption rights were not exercised in July 2011. Their redemption rights expire July 31, 2012. Should the previous owners of Cadence Network exercise their redemption rights, Ecova will seek the necessary funding through its credit facility, a capital request from existing owners, an infusion of capital from potential new investors or a combination of these sources. In January 2011, Avista Capital purchased shares held by one of the previous owners of Cadence Network for $5.6 million.

Pension Plan

As of September 30, 2011, our pension plan had assets with a fair value that was less than the benefit obligation under the plan. We contributed $26 million to the pension plan in 2011 (with no further contributions planned for the fourth quarter of 2011). We expect to contribute a total of $176 million (or $44 million per year) to the pension plan in the period 2012 through 2015. Our estimate of pension plan contributions in this period increased significantly during the third quarter of 2011 (from the previous estimate of $110 million) due to a decline in the fair value of pension plan assets and a decrease in the discount rate used in determining the benefit obligation. The final determination of pension plan contributions for future periods is subject to multiple variables, most of which are beyond our control, including further changes to the fair value of pension plan assets and changes in actuarial assumptions (in particular the discount rate used in determining the benefit obligation).

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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 Credit and Nonperformance Risk and Note 5 of the Notes to Condensed Consolidated Financial Statements. The following table summarizes our credit ratings as of November 4, 2011:

	Standard & Poor s (1)	Moody s (2)
Avista Corporation		
Corporate/Issuer rating	BBB	Baa2
Senior secured debt	A-	A3
Senior unsecured debt	BBB	Baa2
Rating outlook	Stable	Stable

(1) Standard & Poor s lowest level of investment grade credit rating is BBB-. Ratings were upgraded in March 2011. Senior secured debt rating was upgraded in August 2011.

(2) Moody s lowest level of investment grade credit rating is Baa3. Ratings were upgraded in March 2011.

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

Contractual Obligations

Our future contractual obligations have not changed materially from the amounts disclosed in the 2010 Form 10-K, with the following exceptions:

In June 2011, we entered into (through a request for proposals issued in February 2011) a 30-year power purchase agreement (PPA) to acquire all of the power produced by a wind project being developed in Whitman County, Washington. It is expected that the wind project will have a nameplate capacity of approximately 100 megawatts and produce approximately 40 average megawatts with deliveries beginning in the second half of 2012. The power purchased from the project will help to meet our renewable portfolio standards requirements under Washington state law, as well as provide a new energy resource to serve our system retail load requirements. This contract was entered in the ordinary course of our utility business and we believe the cost of the PPA will be recovered through retail rates.

As of September 30, 2011, we had $96.5 million of borrowings outstanding under our committed line of credit. There were $110.0 million in borrowings outstanding as of December 31, 2010.

In the 2010 Form 10-K, we estimated cash contributions to the pension plan of $30 million in 2012, $33 million in 2013, $28 million in 2014 and $21 million in 2015. We have revised these estimates to $44 million each year in the period 2012 through 2015.

Redeemable noncontrolling interests increased to $52.1 million as of September 30, 2011 from $46.7 million as of December 31, 2010 due to the increase in the value, partially offset by the redemption of noncontrolling interests.

Economic Conditions

The general economic data, on both national and local levels, contained in this section are 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.

Economic growth in the region we serve has slowed significantly since it peaked four years ago, yet we continue to experience customer growth. We have three distinct metropolitan areas in our service area and are tracking three separate economic indicators which impact our business: employment change, unemployment rates and foreclosure rates. We have observed mixed results during the economic downturn. The September 2011 employment indicators have turned negative except for Medford, unemployment rates are lower in all three areas while foreclosure rates have increased compared to early periods. Compared to the U.S. our economy is broadly weaker than the national average. We expect our economy to underperform compared to the U.S. in 2012.

Employment in our eastern Washington and northern Idaho service area recently has reversed the gains seen this year, although our southwestern Oregon area continues to improve. Non-farm employment growth for September 2011 compared to September 2010 was 2.9 percent in Medford, Oregon with large gains in manufacturing, health services and retail trade offset by modest declines in government. However, we observed employment declines of 1.2 percent in the Spokane area with losses in professional services and government offset by gains in manufacturing. Employment declined by 0.5 percent in Coeur d Alene, Idaho largely due to government job reductions. The U.S. nonfarm sector jobs grew by 1.1 percent in the same twelve-month period.

The unemployment rate went down in September 2011 from the year earlier level in Spokane, Medford, and Coeur d Alene. The Spokane rate was 8.9 percent in September 2010 but declined to 8.5 percent in September 2011. Medford declined from 11.6 percent to 10.2 percent while Coeur d Alene went from 10.0 percent to 9.2 percent. The U.S. rate declined from 9.2 percent to 8.8 percent in the same period.

The housing market in our service area is weak when measured by foreclosure rates with two of our three metropolitan areas worse than the national average. The September 2011 national rate was 0.16 percent with 0.44 percent in Kootenai County, Idaho and 0.27 percent in Jackson County, Oregon. The Spokane housing market was 0.12 percent.

Environmental Issues and Other Contingencies

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

We monitor legislative and regulatory developments at all levels of government for environmental issues, particularly those with the potential to alter 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, 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.

Climate Change and Greenhouse Gas Emission Reduction Initiatives

Concerns about long-term global climate changes could have a significant effect on our business. Our operations could also be affected by changes in laws and regulations intended to mitigate the risk of 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 impacts hydroelectric generation. Extreme weather events could increase service interruptions, outages and maintenance costs. Changing temperatures could also increase or decrease customer demand.

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

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

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

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

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

National Legislation

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

Recent EPA Initiatives Related to Climate Change

After a public comment and review period, in December 2009, the EPA issued an endangerment finding regarding GHG emissions from motor vehicles under section 202(a) of Clean Air Act (CAA). The EPA found that the current and projected concentrations of the six key well-mixed greenhouse gases - carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride - in the atmosphere threaten the public health and welfare of current and future generations. The EPA also found that the combined emissions of these well-mixed greenhouse gases from new motor vehicles and new motor vehicle engines contribute to the GHG pollution which threatens public health and welfare. The EPA s findings are currently being challenged in the U.S. Court of Appeals for the District of Columbia Circuit. On April 1, 2010, the EPA and the Department of Transportation s National Highway Safety Administration announced a joint final rule establishing GHG emission standards for mobile sources. The GHG emission standards for mobile sources became effective on January 2, 2011. The EPA has concluded that the CAA requires the agency to regulate GHG emissions from stationary sources through its preconstruction and operating permit programs on the date when EPA regulations require any source (mobile or stationary) to meet GHG emission limits. In May 2010, the EPA finalized a rule establishing an applicability threshold for regulating GHG emissions from stationary sources through the preconstruction and operating permit programs.

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

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

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In September 2009, the EPA finalized the Mandatory Reporting Rule (MRR) that requires facilities emitting over 25,000 metric tons of GHG a year to report their emissions to the EPA beginning in January 2011 for 2010 emissions On March 18, 2011, the EPA issued a rule extending the deadline for reporting 2010 GHG emissions data to September 30, 2011. Based on rule applicability criteria, Colstrip, Coyote Springs 2, and the Rathdrum CT recently reported GHGs to the EPA. The rule also required that natural gas distribution system throughput to be reported along with the development of a GHG Monitoring Plan. On March 22, 2010, the EPA proposed to further amend its reporting rule to include several new source categories, including reporting of GHG fugitive emissions from electric power transmission and distribution systems, fugitive emissions from natural gas distribution systems, and fugitive emissions from natural gas storage facilities. Reporting for these additional sources is required by March 31, 2012 for 2011 emissions.

State Activities

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

Washington and Oregon continue to participate in the Western Climate Initiative (WCI), along with the states of Arizona, California, New Mexico, Utah and Montana, and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. The WCI has adopted a regional cap-and-trade program with an overall regional goal for reducing GHG emissions to 15 percent below 2005 levels by 2020. The WCI s program design includes cap-and-trade regulation of the electricity sector in 2012 and of emissions associated with the distribution of natural gas by 2015. Neither Washington, nor Oregon have enacted legislation establishing the WCI s program requirements.

In 2009, the Governor of Washington issued an Executive Order (09-05) directing the Washington Department of Ecology to estimate GHG emissions by sector and source and to identify potential reduction requirements for them in preparation for the eventual imposition of state and/or federal GHG regulations. The Department of Ecology has identified facilities that emit more than 25,000 metric tons of GHG annually and has forecasted that those facilities will need to reduce their emissions by 9.2 percent in order for the state to achieve its GHG emissions reduction target for 2020. Our natural gas distribution system has been specifically identified as a facility along with our thermal plants and contracts with thermal plants. Fossil-fueled generation outside of the state has also been generically identified as a facility for the purposes of potentially regulating emissions associated with the importation of power to serve our Washington loads. The state of Washington has yet to identify how it might impose and enforce emission reductions. Nevertheless, the State will make significant progress in meeting its greenhouse gas emission targets in light of the enactment of SB 5769, which requires the only coal-fired generation facility operating in the state (which we are not involved with) to completely cease coal-fired operations in 2025. In addition, the Department of Ecology has adopted regulations to ensure that Washington s State Implementation Plan comports with the requirements of the EPA s regulation of GHG emissions. We will continue to monitor actions by the department as it may proceed to adopt additional regulations under its Clean Air Act authorities.

Washington and Oregon apply a GHG emissions performance standard to electric generation facilities used to serve loads in their jurisdiction. The emissions performance standard prevents utilities from constructing or purchasing generation facilities, or entering into long-term contracts (five years or more) to purchase energy produced by plants that have emission levels higher than 1,100 pounds of GHG per MWh until 2012, at which time it will be reviewed and may be lowered by administrative rule to reflect the emissions profile of the latest commercially available combined-cycle combustion turbine.

Initiative Measure 937 (I-937), the Energy Independence Act, was passed into law through the 2006 General Election in Washington. I-937 requires investor-owned, cooperative, and government-owned electric utilities with over 25,000 customers to acquire qualified renewable energy resources and/or renewable energy credits in incremental amounts until those resources or credits equal 15 percent of the utility s total retail load in 2020. I-937 also requires these utilities to meet biennial energy conservation targets, the first of which must be met in 2012. Furthermore, by January 1, 2012, electric utilities subject to I-937 s mandates must have acquired enough incremental renewable energy and/or renewable energy credits to meet 3 percent of their load. Failure to comply with renewable energy and energy efficiency standards will result in penalties of at least $50 per MWh being assessed against a utility for each MWh it is deficient in meeting a standard. A utility would be deemed to comply with the renewable energy standard if it invests at least 4 percent of its total annual retail revenue requirement on the incremental costs of renewable energy resources and/or renewable energy credits.

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Electric Integrated Resource Plan

In August 2011, we filed our 2011 Electric Integrated Resource Plan (IRP) with the WUTC and the IPUC. We are required to file an IRP every two years. The IRP details projected load growth and the new resources needed to serve customers over the next 20 years. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project. Highlights of the 2011 IRP include:

- A contract for the 100 megawatt wind project, which is expected to help meet the 2016 requirements in Washington state s Energy Independence Act, as well as provide a new resource to serve our customers increasing energy needs.
- An additional 42 aMW of wind or qualifying renewable energy credits are required annually by 2021.
- Energy efficiency measures are expected to save 310 aMW of cumulative energy over the 20-year IRP timeframe. This aggressive effort could reduce load growth to half of what it would be without these measures.
- 750 MW of new natural gas-fired generation facilities are required between 2018 and 2031.
- Three grid modernization programs are projected to save 5 aMW of energy by 2013.
- Transmission upgrades will be needed to deliver the energy from new generation resources to the distribution lines serving customers. We will continue to participate in regional efforts to expand the region s transmission system.

In June 2011, we entered (through a request for proposals issued in February 2011) into a 30-year power purchase agreement (PPA) with Palouse Wind, LLC (Palouse Wind), an affiliate of First Wind Energy, LLC. Under the PPA, we will acquire all of the power and renewable attributes produced by a wind project being developed by Palouse Wind in Whitman County, Washington. It is expected that the wind project will have a nameplate capacity of approximately 100 megawatts and produce approximately 40 average megawatts with deliveries beginning in the second half of 2012. We decided to enter into this PPA due, in part, to recent market changes reducing the cost of renewable resource projects and tax incentives for the construction of renewable resource projects that remain in effect through 2012. We acquired the development rights for a separate wind generation site near Reardan, Washington in 2008 and continue to study that site in preparation for later development. We plan to meet the state of Washington s renewable energy standards until 2016 with a combination of qualified upgrades at our existing hydroelectric generation plants and the purchase of a small amount of renewable energy credits from 2012 through 2015. The power purchased from Palouse Wind will help to meet our Washington renewable energy requirements beginning in 2016, as well as provide a new energy resource to serve our system retail load requirements. The amount of renewable resources in our future IRPs could change if the cost effectiveness of those resources changes or if a new or modified renewable energy standards are enacted at either the state or federal levels.

As part of our IRP, we included estimates of climate change into the retail load forecast. The recent trend has been a warming climate compared to the 30-year normal. Trends in heating and cooling degree days for Spokane are roughly equal to the scientific community s predictions for this geographic area, implying one degree of warming every 25 years. We do not expect this trend to have a material impact on our results of operations. Estimated costs of GHG emissions were also included in the development of the IRP market prices.

Clean Air Act

We must comply with the requirements under the Clean Air Act (CAA) in operating our thermal generating plants. The CAA currently requires a Title V operating permit for Colstrip (which is in the process of being renewed and is expected to be completed in 2011), Coyote Springs 2 (which will expire in 2013), the Kettle Falls GS (which will be renewed in 2012), and the Rathdrum CT (which was renewed in 2011). Boulder

Park and the Northeast CT currently require only minor source operating permits based on their limited operation and emissions. The CAA also requires Acid Rain Program monitoring, reporting and emissions trading for Colstrip, Coyote Springs 2 and the Rathdrum CT. We continue to monitor legislative and regulatory developments for several programs within the CAA such as the National Ambient Air Quality Standards (NAAQS), New Source Performance Standards and the National Emission Standards for Hazardous Air Pollutants (NESHAPs or MACT).

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Mercury and the proposed EPA Utility MACT

In 2006, the Montana Department of Environmental Quality (Montana DEQ) adopted final rules for the control of mercury emissions from coal-fired plants. The new rules set strict mercury emission limits by 2010, and establish a recurring ten-year review process to ensure facilities are keeping pace with advancing technology in mercury emission control. The rules also provide for temporary alternate emission limits provided certain provisions are met, and they allocate mercury emission credits in a manner that rewards the cleanest facilities. The joint owners of Colstrip believe, based upon current results, that the plant will be able to comply with the Montana law without utilizing the temporary alternate emissions limit provision. The EPA has issued a proposed MACT standard to control hazardous air pollutants including mercury from coal-fired power plants that is expected to become final on December 16, 2011. As currently proposed, the federal standard is slightly less stringent than the Montana DEQ mercury rule. However, due to the uncertainty surrounding the limitations and timing in the final rule, we have not determined to what extent or if there will be any material impacts to Colstrip at this time.

National Ambient Air Quality Standards

We continue to monitor legislative and regulatory developments at both the state and national levels for potential further restrictions on National Ambient Air Quality Standards. New, more stringent ambient air quality standards may be adopted by the EPA for nitrogen dioxide, ozone and particulate matter. We have thermal power plants in Washington, Idaho, Montana and Oregon. Since the EPA has designated most of the western states in which we operate as attainment areas, we do not anticipate any material impacts on our thermal plants from the required updates of these new standards at this time.

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. Should the EPA determine to regulate CCBs as a hazardous waste under the RCRA, such action could have a significant impact on future operations of Colstrip. The EPA has not indicated a clear schedule for final rulemaking.

Fisheries

A number of species of fish in the Northwest, including the Snake River sockeye salmon and fall chinook salmon, the Kootenai River white sturgeon, the upper Columbia River steelhead, the upper Columbia River spring chinook salmon and the bull trout, are listed as threatened or endangered under the Federal Endangered Species Act. Thus far, measures that were adopted and implemented to save the Snake River sockeye salmon and fall chinook salmon have not directly impacted generation levels at any of our hydroelectric facilities (which are on different river systems with the greater Columbia River Basin). We purchase power under long-term contracts with certain PUDs with hydroelectric generation projects on the Columbia River that are directly impacted by ongoing mitigation measures for salmon and steelhead. The reduction in generation at these projects is relatively minor, resulting in minimal economic impact on our operations at this time. We cannot predict the economic costs to us resulting from future mitigation measures. We received a 45-year FERC operating license for Cabinet Gorge and Noxon Rapids in March 2001 that incorporates a comprehensive settlement agreement. The restoration of native salmonid fish, particularly bull trout, is a key part of the agreement. The result is a collaborative bull trout recovery 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, and is currently developing a final Bull Trout Recovery Plan under the ESA. Issues related to these activities are expected to be worked out through the ongoing collaborative effort of our Clark Fork FERC license. See Hydroelectric Licensing and Fish Passage at Cabinet Gorge and Noxon Rapids in Note 11 of the Notes to Condensed Consolidated Financial Statements for further information.

Western Power Market Issues

The FERC continues to conduct proceedings and investigations related to market controls within the western United States that include proposals by certain parties to impose refunds, and some of the FERC s decisions have been appealed in Federal Courts. Certain parties have asserted claims for significant refunds from us, which could result in liabilities for refunding revenues recognized in prior periods. We have joined other parties in opposing these proposals. We believe that we have adequate reserves established for refunds that may be ordered. The refund proceedings provide that any refunds would be offset against unpaid energy debts due to the same party. As of September 30, 2011, our accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from defaulting parties. See California Refund Proceeding and Pacific Northwest Refund Proceeding in Note 11 of the Notes to Condensed Consolidated Financial Statements for further information on the refund proceedings.

Other

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

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

General

Our qualitative general market risk disclosures have not materially changed during the nine months ended September 30, 2011. Please refer to the 2010 Form 10-K.

Commodity Price Risk

Our qualitative commodity price risk disclosures have not materially changed during the nine months ended September 30, 2011. Please refer to the 2010 Form 10-K.

The following table presents energy commodity derivative fair values as a net asset or (liability) as of September 30, 2011 that are expected to settle in each respective year (dollars in thousands):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical	Financial	Physical	Financial	Physical	Financial	Physical	Financial
2011	$ (3,573)	$ (2,841)	$ (13,095)	$ 1,128	$ 1,473	$ 1,103	$ 428	$ (2,752)
2012	(7,827)	(17,865)	(21,510)	(2,864)	413	4,207	(345)	87
2013	(616)	(3,831)	(7,552)	(2,402)	(25)	5,149	(966)	178
2014	296		(1,003)	(595)	(79)	379	(774)	(176)
2015	1,124		39	76	(145)			
Thereafter	6,513				(1,337)			

Credit Risk

Our credit risk has not materially changed during the nine months ended September 30, 2011. Please refer to the 2010 Form 10-K.

Interest Rate Risk

Our qualitative interest rate risk disclosures have not materially changed during the nine months ended September 30, 2011. Please refer to the 2010 Form 10-K.

We enter into forward-starting interest rate swap agreements to manage the risk associated with changes in interest rates and the impact on future interest payments. These interest rate swap agreements relate to the interest payments for anticipated debt issuances. These interest rate swap agreements are considered economic hedges against fluctuations in future cash flows associated with changes in interest rates.

In September 2011, we cash settled interest rate swap contracts (notional amount of $85.0 million) and paid a total of $10.6 million. The interest rate swap contracts were entered during the third quarter of 2011 and were settled in connection with the pricing of $85.0 million of First Mortgage Bonds.

As of September 30, 2011, we had outstanding interest rate swap agreements with a total notional amount of $75.0 million and a mandatory cash settlement date of July 2012. We also have interest rate swap agreements with a notional amount of $85.0 million and a mandatory cash settlement date of June 2013.

As of September 30, 2011, we had a derivative liability of $14.2 million and an offsetting regulatory asset on the Condensed Consolidated Balance Sheets in accordance with regulatory accounting practices. Upon settlement of the interest rate swaps, the regulatory asset or liability (included as part of long-term debt) will be amortized as a component of interest expense over the life of the forecasted interest payments.

Foreign Currency Risk

Our qualitative foreign currency risk disclosures have not materially changed during the nine months ended September 30, 2011. Please refer to the 2010 Form 10-K. As of September 30, 2011, we had a current derivative liability for foreign currency hedges of $0.5 million included in other current assets on the Condensed Consolidated Balance Sheet. As of September 30, 2011, we had entered into 30 Canadian currency forward contracts with a notional amount of $11.3 million ($11.2 million Canadian).

Risk Management

We use a variety of techniques to manage risks for energy resources and wholesale energy market activities. We have an energy resources risk policy and control procedures to manage these risks, both qualitative and quantitative. Please refer to the 2010 Form 10-K for discussion of risk management policies and procedures.

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.

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Item 4. Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended) to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company s management, including its principal executive and principal financial officers as appropriate to allow timely decisions regarding required disclosure. Under the supervision and with the participation of the Company s management, including the Company s principal executive officer and principal financial officer, the Company has evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives. Based upon the Company s evaluation, the Company s principal executive officer and principal financial officer have concluded that the Company s disclosure controls and procedures are effective at a reasonable assurance level as of September 30, 2011.

There have been no changes in the Company s internal control over financial reporting that occurred during the third quarter of 2011 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Please refer to the 2010 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 2010 Form 10-K. In addition to these risk factors, please also see 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 6. Exhibits

12	Computation of ratio of earnings to fixed charges*
15	Letter Re: Unaudited Interim Financial Information*
31.1	Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002)*
31.2	Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002)*
32	Certification of Corporate Officers (Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)**

101	The following financial information from the Quarterly Report on Form 10 Q for the period ended September 30, 2011, formatted in XBRL (Extensible Business Reporting Language) and furnished electronically herewith: (i) the Condensed Consolidated Statements of Income; (ii) Condensed Consolidated Statements of Comprehensive Income; (iii) the Condensed Consolidated Balance Sheets; (iv) the Condensed Consolidated Statements of Cash Flows; (v) the Condensed Consolidated Statements of Equity and Redeemable Noncontrolling Interests; and (vi) the Notes to Condensed Consolidated Financial Statements.**
*	Filed herewith.
**	Furnishedherewith.

SIGNATURE

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

AVISTA CORPORATION
(Registrant)

Date: November 4, 2011

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