FORWARD WITH **FOCUS** | **TOGETHER** WE WILL

AVISTA Corp.

2011 ANNUAL REPORT

WE'RE A GEM OF A COMPANY

SET IN THE PACIFIC NORTHWEST,

MOVING FORWARD

WHILE TAKING CARE OF

TODAY'S BUSINESS.

« ON THE COVER

Together with our customers, investors and retirees, Avista employees are focused on the future while providing excellence in energy services and energy management today.

Scott Morris Chairman, President and Chief Executive Officer

DEAR FELLOW SHAREHOLDERS

AROUND THE WORLD AND IN OUR OWN BACKYARD, PEOPLE SPOKE OUT THIS YEAR.

The messages were different, but the essence was similar: we must work together to achieve common goals. At Avista Corp., we continue to be active listeners and proactive doers in meeting the needs and expectations of our stakeholders.

The customers served by Avista – our utility – need more power every day to energize the ever-growing number of electronics and appliances in their homes and businesses. And we are delivering it – safely, reliably and at a reasonable cost.

Saving money and saving resources are critical business goals for the utilities and facilities served by Ecova (formerly Advantage IQ), our energy and sustainability management business. Ecova helps clients ensure they have the right data, technology and expertise to improve efficiency and lower expenses in their operations.

More than ever, customers' expectations for service quality have been shaped by the dynamic technology of smart phones and tablets that put information instantly at their fingertips. We recognize that the information enabled by advancing technology will continue to drive the change occurring now and in the future. Without a crystal ball, I can't tell you exactly what that change will be, but I can tell you that with our regional utility and our North American energy and sustainability management business, Avista is moving forward with a focus on tomorrow; we're not waiting for it to come to us.

To that end, we've worked hard to refine and shape our strategic initiatives across the company this year, clarifying our objectives and the steps we will take to attain them. You'll read more about these in the following pages. Our goal, as always, is to provide enhanced value for our investors, our customers, our employees and the communities we serve.

TOGETHER WE WILL STRENGTHEN OUR FINANCIAL PERFORMANCE

Avista continued to show a solid financial performance in 2011. Our earnings were $1.72 per diluted share, an increase from $1.65 in 2010. Colder and wetter first-quarter conditions contributed to increased electric and natural gas loads and revenues. In addition, above-average mountain snowpack led to one of the best river run-offs in memory and produced excellent hydroelectric generation for our core business – Avista Utilities.

Continued customer growth – both organically and through strategic acquisitions – at Ecova, our primary unregulated subsidiary, contributed to a 30 percent growth in earnings as compared to 2010.

We are targeting long-term corporate earnings growth of 5 percent to 7 percent. However, our utility earnings in 2011 were limited by slower customer growth than we'd like due to the continued effects of a weak economy in our service area and increased operating expenses, including pension and other post-retirement benefit costs.

Our utility capital expenditures in 2011 totaled approximately $240 million, and we anticipate investing approximately $250 million in each of 2012 and 2013 in electric and natural gas transmission and distribution updates, hydroelectric generation plant upgrades and technology enhancements.

The timely recovery of the costs of capital investments remains one of the biggest challenges in today's utility environment. In 2011, we were able to successfully settle rate cases in Washington and Idaho, which we believe provide a fair and reasonable outcome for our customers and our shareholders. We expect to file rate cases in Washington and Idaho in 2012 to recover ongoing capital investments and the growing cost of assuring reliable energy delivery.

We remain focused on maintaining a healthy balance sheet and strong credit rating. At year-end, Avista had $310 million of available liquidity under our $400 million committed line of credit. We issued $26.5 million of common stock in 2011, including $19.5 million under a sales agency agreement. Plans call for us to issue up to $45 million in equity in 2012 to maintain an appropriate capital structure.

For the ninth consecutive year, the Board of Directors raised the common stock dividend, bringing the annualized dividend to $1.10 per share. With these positive indicators, coupled with upgrades to our credit ratings from Standard & Poor's and Moody's in 2011, Avista continues to be in sound financial shape and a good investment.

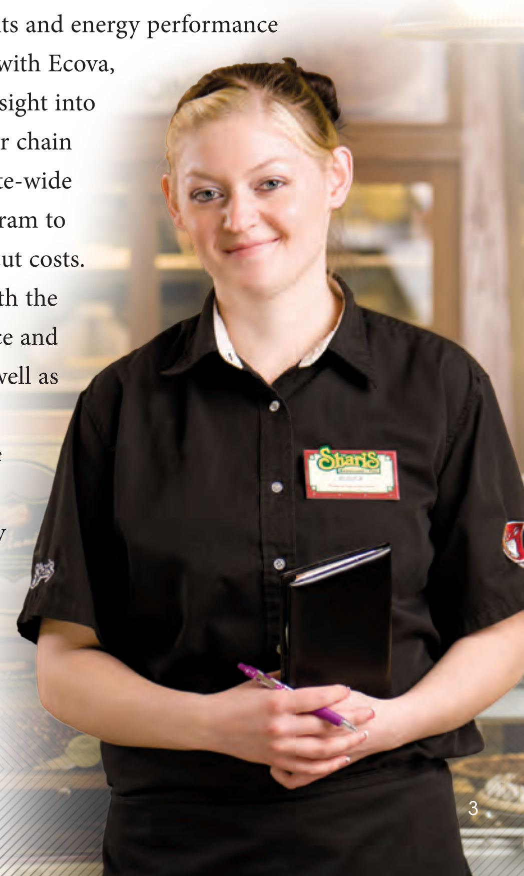
TOGETHER WE WILL DEVELOP NEW WAYS TO DELIVER VALUE TO OUR CUSTOMERS

It's no longer enough to merely meet customers' expectations for service delivery. Today's energy customers want – and demand – products and services to meet their evolving expectations. Throughout our company, we are focused on the intentional design of each customer interaction.

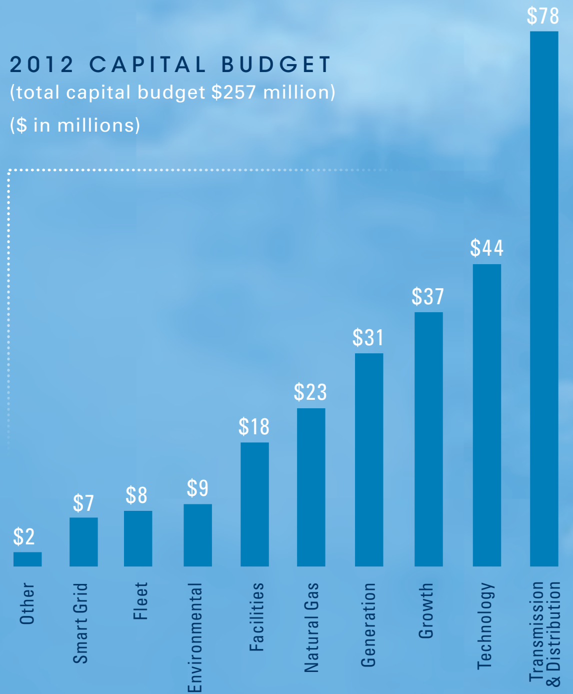
ecova™ For instance, at Ecova we are setting the standard for enhancing the value clients get from their energy and sustainability dollars. We're providing the tools to help them see more – gain visibility and precise insight into inefficiencies; save more – reduce expenses and increase the return on capital investments; and sustain more – build lasting advantages for the bottom line and the environment.

A series of strategic acquisitions over the past 18 months has broadened Ecova's client base and expanded the mix of products, services and expertise we can offer to our clients – primarily large, multi-site companies such as CVS Caremark, Office Depot and Alaska Airlines. In fact, we now count 24 percent of the Fortune 500 companies as our clients. Together with these clients, we processed over $18 billion in energy and resource expenditures in 2011. And these clients see real value from working with Ecova as reflected by our 95 percent retention rate.

Here's an example. When CEO Bruce MacDiarmid joined Shari's Restaurants in 2008, he challenged them to evaluate any operational costs that didn't directly enhance their guests' restaurant dining experience. A financial evaluation identified utility charges as the third-largest controllable expense, making them one of the primary targets for this efficiency initiative. Through a combination of data management, audits and energy performance initiatives in partnership with Ecova, Shari's was able to gain insight into the energy use across their chain and implement a corporate-wide energy management program to improve efficiencies and cut costs. Ecova provided Shari's with the insight necessary to reduce and control consumption, as well as support to interpret and identify the most effective savings opportunities. Shari's was able to quantify the effectiveness of their efforts and reduce energy consumption by 16 percent year over year.



2012 CAPITAL BUDGET
(total capital budget $257 million)
($ in millions)



TOTAL SHAREHOLDER RETURN
(assumes $100 was invested in AVA and each index on Dec. 31, 2006, and that all dividends were reinvested when paid)

The innovative aesthetic spills project at the Upper Falls hydroelectric facility in downtown Spokane involved modifying the river channels to return them to a more natural state, looking more like they did before early 20th century developers cut into the bedrock to collect and funnel water during dry times. Working together with agencies, community members and non-profit organizations, we've enhanced the year-round beauty of the river and its falls, while maintaining adequate flows for power generation.

SPOKANE RIVER AESTHETIC SPILLS PROJECT

TOGETHER WE WILL LEARN

HOW NEW TECHNOLOGIES CAN EMPOWER CUSTOMERS

It seems the technologies we use in our everyday lives change as often as the pages on a calendar. And often those changes come before we even know that we want something newer and better. Who knew you needed a camera in your cell phone before the first one was introduced almost a decade ago? Technology in our everyday lives is driving customers' desire for immediate and accurate information with which to make choices and to take action. Effectively implementing technology is one of the keys to our business in the 21st century. At Avista we take a measured approach to ensuring the technology we are implementing is right for the job and at the right cost for our customers. We prefer to test, watch the technology mature a bit and bring our stakeholders along with us on that journey to assure we are in sync with their goals. That's the approach we're taking with our Smart Grid Demonstration Project in Pullman, Washington.

As we update our energy delivery system, we're committed to working with customers, regulators and project partners to ensure a positive customer experience. New smart grid technologies, enabled by two-way communications, can help customers actively monitor and manage their energy usage and make more informed decisions about choices that drive their energy costs. How these new technologies work in the field and with customers is the focus of our work now.

Customers like Pullman resident Dick Watters learned of our Smart Grid Demonstration Project through a community meeting we hosted. It was one of many Avista outreach efforts he noticed about the project. Watters gained a clear idea from these communications about what to expect from his new advanced meter, as well as how the switch from the old meter to the new meter would take place.

By the time the installation was scheduled, Watters was comfortable with the project and had many opportunities to have his questions answered.

The installation itself was completely unobtrusive. When Watters came home from his office one day, the meter was up and running. He found a note on his door stating that the work was completed and giving him an Avista phone number to call if he had any questions or concerns. Watters had a very positive experience and considers the automation of the meter reading process as a good thing, one that will give him tools to help him understand and manage his energy use.

TOGETHER WE WILL REINFORCE

A VALUES-DRIVEN CULTURE OF PEOPLE WHO DO THE RIGHT THING TO HELP US SUCCEED

In the 30 years I've been with this company, I've grown increasingly proud of the culture that is passed from generation to generation of employees. It fosters innovation and encourages our employees to search out and try new solutions and improvements in business processes, customer satisfaction and integration of new technologies.

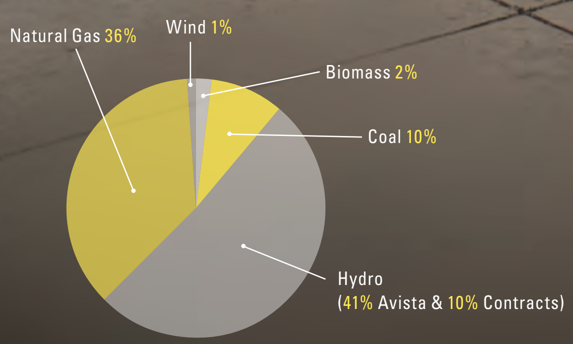
An example of this is the exemplary safety record racked up over the course of a major construction project at our Noxon Rapids Hydroelectric Development on the Clark Fork River in Montana. Built in 1959, this stalwart of power generation possesses the largest generating capacity of Avista's eight hydroelectric developments and boasts the second-largest generating capability of any hydro plant in the state of Montana. Over the last six years, we've invested $75 million to renovate, upgrade and enhance the five generating units at Noxon Rapids, increasing its output while enhancing the wildlife habitat and recreational opportunities along this scenic river. Managing about 150 Avista employees along with hundreds of contractors and vendors on site through the entire construction process was a monumental task. But it is one that has been accomplished with just two minor lost-time incidents in six years. The culture of employee decision-making to ingrain safety as an everyday value is what made this feat a reality.

NOXON RAPIDS ENHANCEMENTS »

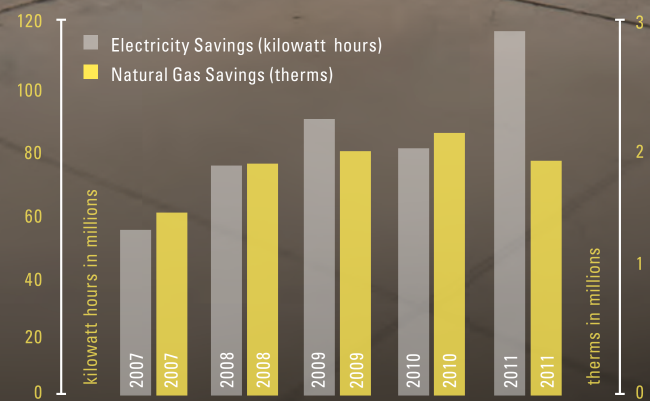
Removing the turbine from the fourth unit at our Noxon Rapids Hydroelectric Development marked the final phase of the six-year restoration project, replacing and upgrading 20th century equipment to meet the energy needs of 21st century customers.

New keyhole construction technology brings precision and cost efficiencies to some of our natural gas repair and maintenance work in neighborhoods throughout our service territory. A small circular section of street pavement is removed, the work is completed and the section is replaced, often with little indication that any underground work had occurred at the site. This eliminates the need for a backhoe and hot patching with asphalt, making it friendlier to the environment – working together to provide services more efficiently, at lower cost and with less impact to customers.

« NATURAL GAS KEYHOLE CONSTRUCTION

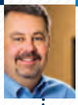


ELECTRICITY GENERATION RESOURCE MIX (as of Dec. 31, 2011)



CUSTOMER ENERGY EFFICIENCY ESTIMATED SAVINGS (as of Dec. 31, 2011)
Washington and Idaho



TOGETHER WE WILL ACT

THROUGH PARTNERSHIPS AND SERVICE TO ENHANCE COMMUNITY VITALITY

Avista is an active partner in building community vitality in the towns and cities throughout our service territory. We find that collaborating with others brings a wide range of voices to the table and engages many in finding the best solutions to the challenges faced in these difficult economic times.

In our hometown of Spokane, Wash., many of our employees are involved in the build-out of the University District – reclaiming a neighborhood of abandoned warehouses and railroad tracks out of which new buildings are rising from the dust. They are filling with classrooms and learning resources outfitted with state-of-the-art technology. Avista is collaborating with regional universities and health providers in the development of a new Academic Health Science Center. When it is complete in 2013, it will house a four-year medical program, pharmacy, nursing, dentistry and other allied health and research programs. We envision that it will be a catalyst for creating new and sustained growth throughout our utility service area and for the entire Pacific Northwest.

LOOKING AHEAD TO A BRIGHT FUTURE

In the short-term for our utility, we will continue to invest in our infrastructure – replacing aging equipment and integrating proven, new technology as it makes sense financially and operationally. By continuing this commitment, we ensure that our customers have the safe, reliable energy and value-added services they have come to expect.

In the long-term, we are focused on a strong and steady financial performance, bringing value to our shareholders and our customers through improved service delivery, operational efficiencies and effective regulatory outcomes, while seeking new innovations in energy for the future. Our goal is to achieve optimum life-cycle performance of our assets – the pipes, the poles and the wires – as well as sustain the institutional knowledge developed through years of experience in energy and its management.

In addition, we'll continue to grow Ecova through increasing our value for our clients, expanding our share of resources that are managed for them and extending our value across additional business opportunities.

As the demographics of our workforce shift with baby boomer retirements, I'm seeing incredible new talent in our company – the next generation of Avista. In planning for our future, we leave little to chance with succession plans and active leadership development in progress. I am confident the employees of Avista will continue the excellence our company is known for, providing reliable energy services and the choices that mean the most to our customers.

Sincerely,

Scott Morris

Scott L. Morris

Chairman, President and Chief Executive Officer

BOARD COMITTEES

Corporate Governance/ Nominating Committee
Kristianne Blake
Marc F. Racicot
R. John Taylor
John F. Kelly – Chair

Executive Committee
Kristianne Blake
John F. Kelly
R. John Taylor
Scott L. Morris – Chair

Audit Committee
Donald C. Burke
Michael L. Noël (Financial Expert)
Heidi B. Stanley
Kristianne Blake – Chair

Compensation & Organization Committee
John F. Kelly
Rebecca A. Klein
Michael L. Noël
R. John Taylor – Chair

Finance Committee
Donald C. Burke
Rick R. Holley
Heidi B. Stanley
Erik J. Anderson – Chair

Energy, Environmental & Operations Committee
Erik J. Anderson
Rick R. Holley
Marc F. Racicot
Rebecca A. Klein – Chair

CORPORATE & BUSINESS UNIT OFFICERS

Scott L. Morris, 54
Chairman of the Board,
President & CEO

Mark T. Thies, 48
Senior Vice President & CFO

Marian M. Durkin, 58
Senior Vice President,
General Counsel &
Chief Compliance Officer

Karen S. Feltes, 56
Senior Vice President &
Corporate Secretary

Dennis P. Vermillion, 50
Senior Vice President &
Environmental Compliance
Officer
President, Avista Utilities

Christy M. Burmeister-Smith, 55
Vice President, Controller &
Principal Accounting Officer

James M. Kensok, 53
Vice President & CIO

Don F. Kopczynski, 56
Vice President

David J. Meyer, 58
Vice President &
Chief Counsel for Regulatory
& Governmental Affairs

Kelly O. Norwood, 53
Vice President

Richard L. Storro, 61
Vice President

Jason R. Thackston, 42
Vice President

Roger D. Woodworth, 55
Vice President

Diane C. Thoren, 59
Treasurer

Jeffrey D. Heggedahl, 47
President & CEO, Ecova, Inc.

BOARD OF DIRECTORS

Erik J. Anderson, 53
President
Westriver Capital
Kirkland, Washington
Director since 2000

Kristianne Blake, 58
President
Kristianne Gates Blake, P.S.
Spokane, Washington
Director since 2000

Donald C. Burke, 51
CPA
Langhorne, Pennsylvania
Director since 2011

Rick R. Holley, 60
President & CEO
Plum Creek Timber Co., Inc.
Seattle, Washington
Director since 2011

John F. Kelly, 67
President & CEO
John F. Kelly & Associates
Coral Gables, Florida
Director since 1997

Rebecca A. Klein, 46
Principal
Klein Energy, LLC
Austin, Texas
Director since 2010

Scott L. Morris, 54
Chairman of the Board,
President & CEO
Avista Corp.
Spokane, Washington
Director since 2007

Michael L. Noël, 70
President
Noël Consulting Company
Prescott, Arizona
Director since 2004

Marc F. Racicot, 63
Bigfork, Montana
Director since 2009

Heidi B. Stanley, 55
Co-owner & Chair
Empire Bolt & Screw, Inc.
Spokane, Washington
Director since 2006

R. John Taylor, 62
Chairman & CEO
CropUSA Insurance Agency
Lewiston, Idaho
Director since 1985

Pictured left to right at the New York Stock Exchange

Front row: Rebecca Klein, Heidi Stanley and Kristianne Blake

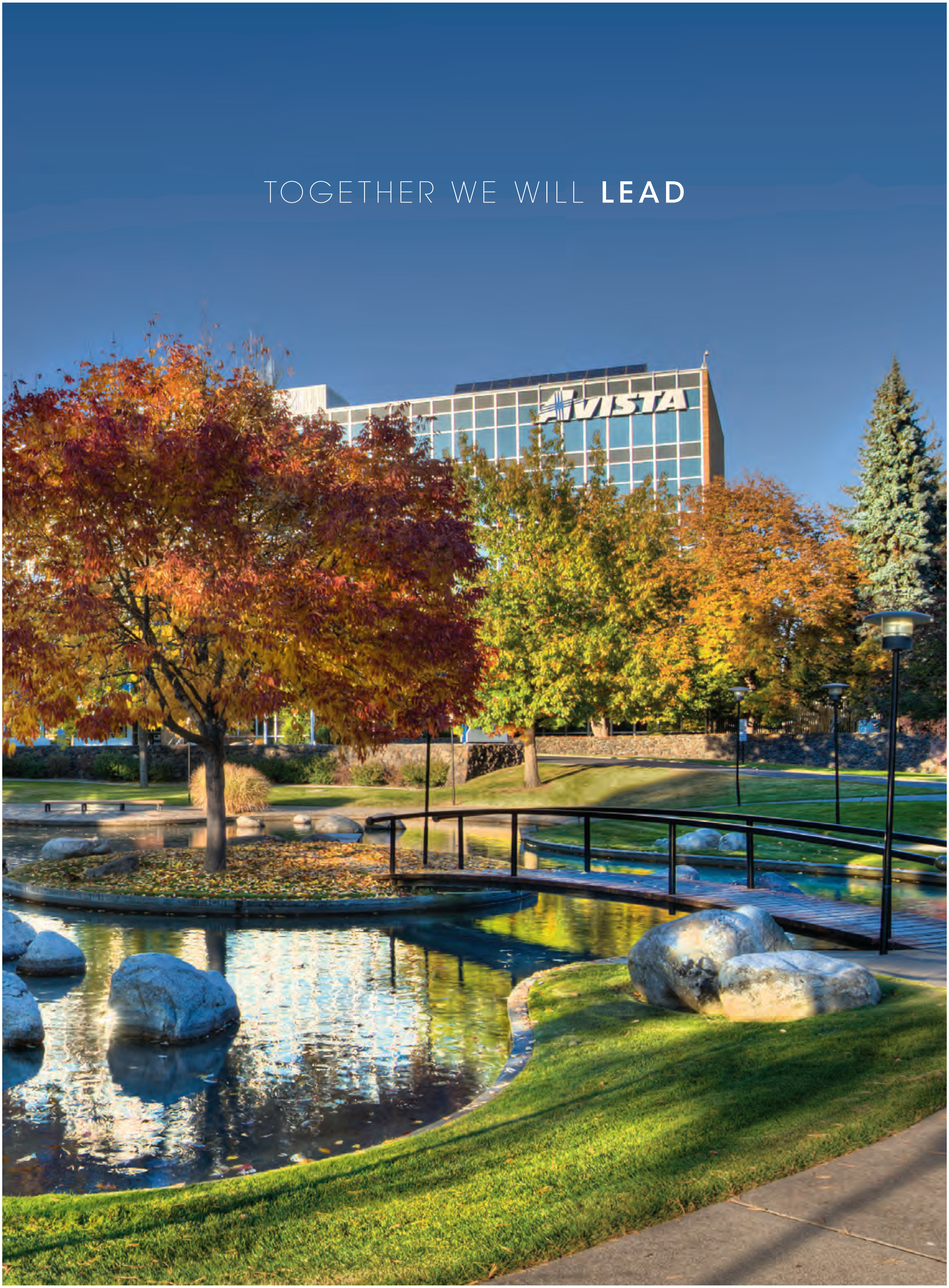
Back row: Marc Racicot, Don Burke, Erik Anderson, Scott Morris, John Taylor, Michael Noël and John Kelly

Not pictured: Rick Holley

FINANCIAL AND OPERATING HIGHLIGHTS

(dollars in thousands except statistics and per share amounts or as otherwise indicated)	**2011**	2010	2009
FINANCIAL RESULTS			
Operating revenues	**$ 1,619,780**	$ 1,558,740	$ 1,512,565
Operating expenses	**1,384,158**	1,328,552	1,311,907
Income from operations	**235,622**	230,188	200,658
Net income	**103,539**	94,948	88,648
Net income attributable to Avista Corporation	**100,224**	92,425	87,071
Earnings per common share attributable to Avista Corporation, diluted	**1.72**	1.65	1.58
Earnings per common share attributable to Avista Corporation, basic	**1.73**	1.66	1.59
Dividends paid per common share	**1.10**	1.00	0.81
Book value per common share	**$ 20.30**	$ 19.71	$ 19.17
Average common shares outstanding	**57,872**	55,595	54,694
Actual common shares outstanding	**58,423**	57,120	54,837
Return on average Avista Corporation stockholders' equity	**8.7%**	8.5%	8.5%
Common stock closing price	**$ 25.75**	$ 22.52	$ 21.59
OPERATING RESULTS			
Avista Utilities			
Retail electric revenues	**$ 734,475**	$ 683,340	$ 703,951
Retail kWh sales (in millions)	**9,023**	8,843	8,942
Retail electric customers at year-end	**360,361**	358,895	356,536
Wholesale electric revenues	**$ 78,305**	$ 165,553	$ 88,414
Wholesale kWh sales (in millions)	**2,796**	3,803	2,354
Sales of fuel	**$ 153,470**	$ 106,375	$ 32,992
Other electric revenues	**21,937**	19,015	15,426
Retail natural gas revenues	**338,220**	297,920	396,203
Wholesale natural gas revenues	**195,882**	197,364	143,524
Transportation and other natural gas revenues	**$ 14,123**	$ 15,965	$ 14,691
Total therms delivered (in thousands)	**1,006,413**	923,096	888,301
Retail natural gas customers at year-end	**320,592**	318,996	316,201
Net income attributable to Avista Corporation	**$ 90,902**	$ 86,681	$ 86,744
Ecova			
Revenues	**$ 137,848**	$ 102,035	$ 77,275
Net income attributable to Avista Corporation	**9,671**	7,433	5,329
Other			
Revenues	**$ 40,410**	$ 61,067	$ 40,089
Net loss attributable to Avista Corporation	**(349)**	(1,689)	(5,002)
FINANCIAL CONDITION			
Total assets	**$ 4,214,531**	$ 3,940,095	$ 3,606,959
Long-term debt (including current portion)	**1,177,300**	1,101,857	1,071,338
Nonrecourse long-term debt of Spokane Energy (including current portion)	**46,471**	58,934	—
Long-term debt to affiliated trusts	**51,547**	51,547	51,547
Total Avista Corporation stockholders' equity	**$ 1,185,701**	$ 1,125,784	$ 1,051,287

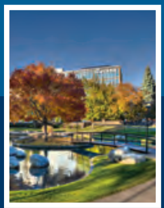
TOGETHER WE WILL **LEAD**



AVISTA CORP (AVA)

FORM 10-K

Filed: February 28, 2012
(Period: December 31, 2011)
Annual report which provides a comprehensive overview of the company for the past year.



TOGETHER WE WILL LEAD

Avista's headquarters building – constructed in 1958 – is undergoing renovation to ready it for at least another 50 years of service. For the work completed so far, the U.S. Green Building Council awarded Avista two LEED (Leadership in Energy and Environmental Design) Gold Certifications for Commercial Interiors and recognized Avista's work as "a pioneeering example of sustainable design."

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

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED **DECEMBER 31, 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

Securities registered pursuant to Section 12(b) of the Act:

Title of Class	Name of Each Exchange on Which Registered
Common Stock, no par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Title of Class
Preferred Stock, Cumulative, Without Par Value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
Yes ☐ No ☒

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

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

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

The aggregate market value of the Registrant's outstanding Common Stock, no par value (the only class of voting stock), held by non-affiliates is $1,489,452,508 based on the last reported sale price thereof on the consolidated tape on June 30, 2011.

As of January 31, 2012, 58, 554, 301 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

Documents Incorporated By Reference

Document	Part of Form 10-K into Which Document is Incorporated
Proxy Statement to be filed in connection with the annual meeting of shareholders to be held May 10, 2012	Part III, Items 10, 11, 12, 13 and 14

INDEX

ITEM NO.		PAGE NO.
	Acronyms and Terms	IV
	Forward-Looking Statements	1
	Available Information	2

PART I

1.	Business	2
	Company Overview	2
	Avista Utilities	3
	General	3
	Electric Operations	3
	Electric Requirements	3
	Electric Resources	3
	Hydroelectric Licensing	5
	Future Resource Needs	5
	Natural Gas Operations	6
	Regulatory Issues	6
	Federal Laws Related to Wholesale Competition	7
	Regional Transmission Organizations	7
	Reliability Standards	8
	Avista Utilities Operating Statistics	9
	Ecova (formerly known as Advantage IQ)	12
	Other Businesses	12
1A.	Risk Factors	13
1B.	Unresolved Staff Comments	16
2.	Properties	17
	Avista Utilities	17
3.	Legal Proceedings	18
4.	Mine Safety Disclosures	18*

PART II

5.	Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	18
6.	Selected Financial Data	20
7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	21
	Business Segments	21
	Executive Level Summary	21
	Avista Utilities — Regulatory Matters	22
	Results of Operations	25
	Avista Utilities	26
	Ecova	31
	Other Businesses	32
	Accounting Standards to Be Adopted in 2012	32
	Critical Accounting Policies and Estimates	32
	Liquidity and Capital Resources	35
	Review of Cash Flow Statement	35
	Overall Liquidity	35
	Credit and Nonperformance Risk	36
	Dodd-Frank Wall Street Reform and Consumer Protection Act	36
	Capital Resources	37
	Avista Utilities Capital Expenditures	38
	Ecova Credit Agreement	38

ITEM NO.		PAGE NO.
	Ecova Redeemable Stock	38
	Off-Balance Sheet Arrangements	38
	Pension Plan	39
	Credit Ratings	39
	Dividends	39
	Contractual Obligations	40
	Competition	40
	Economic Conditions and Utility Load Growth	41
	Environmental Issues and Other Contingencies	42
7A.	Quantitative and Qualitative Disclosures about Market Risk	45
8.	Financial Statements and Supplementary Data	49
	Report of Independent Registered Public Accounting Firm	50
	Financial Statements	51-57
	Consolidated Statements of Income	51
	Consolidated Statements of Comprehensive Income	52
	Consolidated Balance Sheets	53-54
	Consolidated Statements of Cash Flows	55-56
	Consolidated Statements of Equity and Redeemable Noncontrolling Interests	57
	Notes to Consolidated Financial Statements	58-96
	Note 1. Summary of Significant Accounting Policies	58
	Note 2. New Accounting Standards	63
	Note 3. Variable Interest Entities	64
	Note 4. Impairment of Assets	64
	Note 5. Redeemable Noncontrolling Interests and Subsidiary Acquisitions	64
	Note 6. Derivatives and Risk Management	65
	Note 7. Jointly Owned Electric Facilities	68
	Note 8. Property, Plant and Equipment	69
	Note 9. Asset Retirement Obligations	69
	Note 10. Pension Plans and Other Postretirement Benefit Plans	70
	Note 11. Accounting for Income Taxes	75
	Note 12. Energy Purchase Contracts	76
	Note 13. Short-Term Borrowings	78
	Note 14. Long-Term Debt	79
	Note 15. Long-Term Debt to Affiliated Trusts	80
	Note 16. Leases	80
	Note 17. Fair Value	81
	Note 18. Common Stock	83
	Note 19. Earnings per Common Share Attributable to Avista Corporation	84
	Note 20. Stock Compensation Plans	84
	Note 21. Commitments and Contingencies	87
	Note 22. Information Services Contracts	91
	Note 23. Avista Utilities Regulatory Matters	92
	Note 24. Information by Business Segments	95
	Note 25. Selected Quarterly Financial Data (Unaudited)	96
9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	97*
9A.	Controls and Procedures	97
9B.	Other Information	99

PART III

10.	Directors, Executive Officers and Corporate Governance	99
11.	Executive Compensation	100
12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	101

INDEX (CONTINUED)

ITEM NO.		PAGE NO.
13.	Certain Relationships and Related Transactions, and Director Independence	101
14.	Principal Accounting Fees and Services	101

PART IV

15.	Exhibits, Financial Statement Schedules	102
	Signatures	103
	Exhibit Index	104

** = not an applicable item in the 2011 calendar year for Avista Corporation*

ACRONYMS AND TERMS

(The following acronyms and terms are found in multiple locations within the document)

Acronym/Term	Meaning
aMW	– Average Megawatt — a measure of the average rate at which a particular generating source produces energy over a period of time
AFUDC	– Allowance for Funds Used During Construction; represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period
AM&D	– Advanced Manufacturing and Development, does business as METALfx
ASC	– Accounting Standards Codification
Avista Capital	– Parent company to the Company's non-utility businesses
Avista Corp.	– Avista Corporation, the Company
Avista Energy	– Avista Energy, Inc., an electricity and natural gas marketing, trading and resource management business, subsidiary of Avista Capital
Avista Utilities	– Operating division of Avista Corp. comprising the regulated utility operations
BPA	– Bonneville Power Administration
Capacity	– The rate at which a particular generating source is capable of producing energy, measured in KW or MW
Cabinet Gorge	– The Cabinet Gorge Hydroelectric Generating Project, located on the Clark Fork River in Idaho
Colstrip	– The coal-fired Colstrip Generating Plant in southeastern Montana
Coyote Springs 2	– The natural gas-fired Coyote Springs 2 Generating Plant located near Boardman, Oregon
CT	– Combustion turbine
Deadband or ERM deadband	– The first $4.0 million in annual power supply costs above or below the amount included in base retail rates in Washington under the Energy Recovery Mechanism in the state of Washington
Dekatherm	– Unit of measurement for natural gas; a dekatherm is equal to approximately one thousand cubic feet (volume) or 1,000,000 BTUs (energy)
DOE	– The state of Washington's Department of Ecology
Ecos	– A Portland, Oregon-based energy efficiency solutions provider acquired by Ecova in 2009
Ecova	– Formerly known as Advantage IQ, Inc. (Advantage IQ), provider of facility information and cost management services for multi-site customers throughout North America, subsidiary of Avista Capital
Energy	– The amount of electricity produced or consumed over a period of time, measured in kWh or MWh
EPA	– Environmental Protection Agency
ERM	– The Energy Recovery Mechanism in the state of Washington
FASB	– Financial Accounting Standards Board

Acronym/Term	Meaning
FERC	– Federal Energy Regulatory Commission
GHG	– Greenhouse gas
IPUC	– Idaho Public Utilities Commission
IRP	– Integrated Resource Plan
Jackson Prairie	– Jackson Prairie Natural Gas Storage Project, an underground natural gas storage field located near Chehalis, Washington
kV	– Kilovolt or 1000 volts, a measure of capacity on transmission lines
kW, kWh	– Kilowatt or 1000 watts a measure of generating output, kilowatt-hour or 1000 watt hours a measure of energy produced
Lancaster Plant	– A natural gas-fired combined cycle combustion turbine plant located in Idaho
MW, MWh	– Megawatt or 1000 kW, megawatt-hour or 1000 kWh
NERC	– North American Electricity Reliability Corporation
Noxon Rapids	– The Noxon Rapids Hydroelectric Generating Project, located on the Clark Fork River in Montana
OPUC	– The Public Utility Commission of Oregon
PCA	– The Power Cost Adjustment mechanism in the state of Idaho
PGA	– Purchased Gas Adjustment
PLP	– Potentially liable party
PUD	– Public Utility District
PURPA	– The Public Utility Regulatory Policies Act of 1978, as amended
RTO	– Regional Transmission Organization
Spokane Energy	– Spokane Energy, LLC, a special purpose limited liability company and all of its membership capital is owned by Avista Corp.
Spokane River Project	– The five hydroelectric plants operating under one FERC license on the Spokane River (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls)
Therm	– Unit of measurement for natural gas; a therm is equal to approximately one hundred cubic feet (volume) or 100,000 BTUs (energy)
Watt	– Unit of measurement for electricity; a watt is equal to the rate of work represented by a current of one ampere under a pressure of one volt
WUTC	– Washington Utilities and Transportation Commission

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 Annual Report on Form 10-K), and elsewhere. Forward-looking statements are all statements except those of historical fact including, without limitation, those that are identified by the use of words that include "will," "may," "could," "should," "intends," "plans," "seeks," "anticipates," "estimates," "expects," "forecasts," "projects," "predicts," and similar expressions. Forward-looking statements (including those made in this Annual Report on Form 10-K) are subject to a variety of risks and uncertainties and other factors. Many of these factors are beyond our control and they could have a significant effect on our operations, results of operations, financial condition or cash flows. This could cause actual results to differ materially from those anticipated in our statements. Such risks, uncertainties and other factors include, among others:

- weather conditions (temperatures, precipitation levels and wind patterns) and their effects on energy demand and electric generation, including the effect of precipitation and temperatures on the availability of hydroelectric resources, the effect of wind patterns on the availability of wind resources, the effect of temperatures on customer demand, and similar impacts on supply and demand in the wholesale energy markets;
- the effect of state and federal regulatory decisions on our ability to recover costs and earn a reasonable return including, but not limited to, the disallowance of costs and investments, and delay in the recovery of capital investments and operating costs;
- changes in wholesale energy prices that can affect, among other things, the cash requirements to purchase electricity and natural gas, the value received for sales in the wholesale energy market, the necessity to request changes in rates that are subject to regulatory approval, collateral required of us by counterparties on wholesale energy transactions and credit risk to us from such transactions, and the market value of derivative assets and liabilities;
- economic conditions in our service areas, including the effect on the demand for, and customers' payment for, our utility services;
- global financial and economic conditions (including the impact on capital markets) and their effect on our ability to obtain funding at a reasonable cost;
- our ability to obtain financing through the issuance of debt and/or equity securities, which can be affected by various factors including our credit ratings, interest rates and other capital market conditions;
- the potential effects of legislation or administrative rulemaking, including the possible adoption of national or state laws requiring our resources to meet certain standards and placing restrictions on greenhouse gas emissions to mitigate concerns over global climate changes;
- changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension plan, which can affect future funding obligations, pension expense and pension plan liabilities;
- volatility and illiquidity in wholesale energy markets, including the availability of willing buyers and sellers, and prices of purchased energy and demand for energy sales;
- unplanned outages at any of our generating facilities or the inability of facilities to operate as intended;
- the outcome of pending regulatory and legal proceedings arising out of the "western energy crisis" of 2000 and 2001, including possible refunds;
- the outcome of legal proceedings and other contingencies;
- changes in, and compliance with, environmental and endangered species laws, regulations, decisions and policies, including present and potential environmental remediation costs;
- wholesale and retail competition including, but not limited to, alternative energy sources, suppliers and delivery arrangements;
- the ability to comply with the terms of the licenses for our hydroelectric generating facilities at cost-effective levels;
- natural disasters that can disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies and support services;
- explosions, fires, accidents, or mechanical breakdowns that may occur while operating and maintaining our generation, transmission and distribution systems;
- 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;
- changes in the payment acceptance policies of Ecova's client vendors that could reduce operating revenues;
- potential difficulties for Ecova in integrating acquired operations and in realizing expected opportunities, diversions of management resources and losses of key employees, challenges with respect to operating new businesses and other unanticipated risks and liabilities; and
- changes in our strategic business plans, which may be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses.

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

AVAILABLE INFORMATION

Our Web site address is www.avistacorp.com. We make annual, quarterly and current reports available at our Web site as soon as practicable after electronically filing these reports with the Securities and Exchange Commission. Information contained on our Web site is not part of this report.

PART I

ITEM 1. BUSINESS

COMPANY OVERVIEW

Avista Corporation (Avista Corp. or the Company), incorporated in the state of Washington in 1889, is an energy company engaged in the generation, transmission and distribution of energy as well as other energy-related businesses. As of December 31, 2011, we employed 1,594 people in our utility operations and 1,215 people in our subsidiary businesses. Our corporate headquarters are in Spokane, Washington, the second-largest city in Washington state. Spokane serves as the business, transportation, medical, industrial and cultural hub of the Inland Northwest region. Of all the forces that have shaped the Spokane County economy, none is more significant than Spokane's historic role as a regional center of services for the surrounding rural populations of eastern Washington and northern Idaho. Regional services include government and higher education, medical services, retail trade and finance. The Inland Northwest also coincides closely with our utility service area in Washington and Idaho but is separate from our service area in southwest Oregon.

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 known as Advantage IQ)** — an indirect subsidiary of Avista Corp. (79.2 percent owned as of December 31, 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 and telecom 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 a sheet metal fabrication business, emerging technology venture fund investments and commercial real estate investments, as well as Spokane Energy, LLC (Spokane Energy). These activities do not represent a reportable business segment and are conducted by various indirect subsidiaries of Avista Corp.

Ecova and various other companies are subsidiaries of Avista Capital, Inc. (Avista Capital) which is a direct, wholly owned subsidiary of Avista Corp. Total Avista Corp. stockholders' equity was $1,185.7 million as of December 31, 2011, of which $72.0 million represented our investment in Avista Capital.

See "Item 6. Selected Financial Data" and "Note 24 of the Notes to Consolidated Financial Statements" for information with respect to the operating performance of each business segment (and other subsidiaries).

AVISTA UTILITIES

General

Through our regulated utility operations, we generate, transmit and distribute electricity and distribute natural gas. Retail electric and natural gas customers include residential, commercial and industrial classifications. We also engage in wholesale purchases and sales of electricity and natural gas as an integral part of energy resource management and our load-serving obligation.

Our utility provides electric distribution and transmission, as well as natural gas distribution services in parts of eastern Washington and northern Idaho. We also provide natural gas distribution service in parts of northeast and southwest Oregon. At the end of 2011, we supplied retail electric service to 360,000 customers and retail natural gas service to 321,000 customers across our entire service territory. Our service territory covers 30,000 square miles with a population of 1.5 million. See "Item 2. Properties" for further information on our utility assets. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Economic Conditions and Utility Load Growth" for information on economic conditions in our service territory.

Electric Operations

In addition to providing electric distribution and transmission services, we generate electricity from facilities that we own and we purchase capacity and energy and fuel for generation under long-term and short-term contracts. We also sell electric capacity and energy, as well as surplus fuel in the wholesale market in connection with our resource optimization activities as described below.

As part of our resource procurement and management operations in the electric business, we engage in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve our load obligations and the use of these resources to capture available economic value. We sell and purchase electric capacity and energy and fuel in wholesale markets as part of the process of acquiring and balancing resources to serve our load obligations. These transactions range from terms of 30 minutes up to multiple years. We make continuing projections of:

- electric loads at various points in time (ranging from 30 minutes to multiple years) based on, among other things, estimates of customer usage and weather, historical data and contract terms, and
- resource availability at these points in time based on, among other things, fuel choices and fuel markets, estimates of streamflows, availability of generating units, historic and forward market information, contract terms, and experience.

On the basis of these projections, we make 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.

Our optimization process includes entering into hedging transactions to manage risks.

Our generation assets are interconnected through the regional transmission system and are operated on a coordinated basis to enhance load-serving capability and reliability. We provide transmission and ancillary services in eastern Washington, northern Idaho and western Montana. Transmission revenues were $13.8 million in 2011, $12.8 million in 2010 and $9.3 million in 2009.

Electric Requirements

Our peak electric native load requirement for 2011 occurred on January 11, 2011 at which time our total obligation was 2,381 MW consisting of:

- native load of 1,669 MW,
- long-term wholesale obligations of 243 MW, and
- short-term wholesale obligations of 469 MW.

At that time our maximum resource capacity available was 2,923 MW, which included:

- company-owned or controlled electric generation of 1,756 MW,
- long-term hydroelectric contracts with certain Public Utility Districts (PUDs) of 124 MW,
- long-term thermal generation contract with Lancaster Plant of 279 MW,
- other long-term wholesale contracts of 189 MW, and
- short-term wholesale purchases of 575 MW.

Electric Resources

We have a diverse electric resource mix of hydroelectric projects, thermal generating facilities, and power purchases and exchanges.

At the end of 2011, our facilities had a total net capability of 1,791 MW, of which 56 percent was hydroelectric and 44 percent was thermal. See "Item 2. Properties" for detailed information on generating facilities.

Hydroelectric Resources — We own and operate six hydroelectric projects on the Spokane River and two hydroelectric projects on the Clark Fork River. Hydroelectric generation is our lowest cost source per megawatt-hour (MWh) of electricity and the availability of hydroelectric generation has a significant effect on total power supply costs. Under normal streamflow and operating conditions, we estimate that we would be able to meet approximately one-half of our total average electric requirements (both retail and long-term wholesale) with the combination of our hydroelectric generation and long-term hydroelectric purchase contracts with certain PUDs in the state of Washington. Our estimate of normal annual hydroelectric generation for 2012 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 542 average megawatts (aMW) (or 4.76 million MWhs). Hydroelectric resources provided 637 aMW for 2011, 476 aMW for 2010 and 526 aMW for 2009.

The following table shows our hydroelectric generation (in thousands of MWhs) during the year ended December 31:

	2011	2010	2009
Noxon Rapids	2,110	1,503	1,673
Cabinet Gorge	1,292	942	1,061
Post Falls	90	90	84
Upper Falls	73	71	52
Monroe Street	110	106	104
Nine Mile	90	101	106
Long Lake	556	480	487
Little Falls	213	201	199
Total company-owned hydroelectric generation	4,534	3,494	3,766
Long-term hydroelectric contracts with PUDs	1,047	685	839
Total hydroelectric generation	5,581	4,179	4,605

Thermal Resources — We own:

- the combined cycle combustion turbine (CT) natural gas-fired Coyote Springs 2 Generation Project (Coyote Springs 2) located near Boardman, Oregon,
- a 15 percent interest in a twin-unit, coal-fired boiler generating facility, the Colstrip 3 & 4 Generating Project (Colstrip) in southeastern Montana,
- a wood waste-fired boiler generating facility known as the Kettle Falls Generating Station (Kettle Falls GS) in northeastern Washington,
- a two-unit natural gas-fired CT generating facility, located in northeast Spokane (Northeast CT),
- a two-unit natural gas-fired CT generating facility in northern Idaho (Rathdrum CT), and
- two small natural gas-fired generating facilities (Boulder Park and Kettle Falls CT).

Coyote Springs 2, which is operated by Portland General Electric Company, is supplied with natural gas under both term contracts and spot market purchases, including transportation agreements with unilateral renewal rights.

Colstrip, which is operated by PPL Montana, LLC, is supplied with fuel from adjacent coal reserves under coal supply and transportation agreements in effect through 2019.

The primary fuel for the Kettle Falls GS is wood waste generated as a by-product and delivered by trucks from forest industry operations within 100 miles of the plant. A combination of long-term contracts and spot purchases has provided, and is expected to meet, fuel requirements for the Kettle Falls GS.

The Northeast CT, Rathdrum CT, Boulder Park and Kettle Falls CT generating units are primarily used to meet peaking electric requirements. We also operate these facilities when marginal costs are below prevailing wholesale electric prices. These generating facilities have access to natural gas supplies that are adequate to meet their respective operating needs.

The following table shows our thermal generation (in thousands of MWhs) during the year ended December 31:

	2011	2010	2009
Coyote Springs 2	705	1,661	1,559
Colstrip	1,433	1,749	1,277
Kettle Falls GS	291	312	184
Northeast CT and Rathdrum CT	8	12	44
Boulder Park and Kettle Falls CT	10	14	33
Total company-owned thermal generation	2,447	3,748	3,097
Long-term contract with Lancaster Plant	835	1,410	—
Total thermal generation	3,282	5,158	3,097

Lancaster Plant Power Purchase Agreement — The Lancaster Plant is a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho, owned by an unrelated third-party. All of the output from the Lancaster Plant is contracted to us through 2026 under a power purchase agreement (PPA).

Palouse Wind PPA — In June 2011, we entered into a 30-year PPA with Palouse Wind, LLC (Palouse Wind), an affiliate of First Wind Holdings, LLC. Under the PPA, we will acquire all of the power and renewable attributes produced by a wind project being developed by Palouse Wind in Whitman County, Washington. The wind project is expected to have a nameplate capacity of approximately 105 MW and produce approximately 40 aMW with deliveries by the end of 2012. We decided to enter this PPA due, in part, to market changes reducing the cost of renewable resource projects. This was due, in part, to tax incentives for the construction of renewable resource projects that remain in effect through 2012. The power purchased from Palouse Wind will help to meet our Washington renewable energy requirements beginning in 2016, as well as provide a new energy resource to serve our system retail load requirements. Under the PPA, we have the option to purchase the wind project each year following the 10th anniversary of the commercial operation date at a price determined under the contract.

Other Purchases, Exchanges and Sales — We purchase and sell power under various long-term contracts. We also enter into short-term purchases and sales. See "Electric Operations" for additional information with respect to the use of wholesale purchases and sales as part of our resource optimization process.

Pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA), as amended, we are required to purchase generation from qualifying facilities. This includes, among other resources, hydroelectric projects, cogeneration projects and wind generation projects at rates approved by the WUTC and the IPUC. Existing contracts expire at various times through 2022.

See "Avista Utilities Operating Statistics — Electric Operations — Electric Energy Resources" for annual quantities of purchased power, wholesale power sales and power from exchanges in 2011, 2010 and 2009.

Hydroelectric Licensing

We are a licensee under the Federal Power Act as administered by the FERC, which includes regulation of hydroelectric generation resources. Except for the Little Falls Plant, all of our hydroelectric plants are regulated by the FERC through project licenses. The licensed projects are subject to the provisions of Part I of the Federal Power Act. These provisions include payment for headwater benefits, condemnation of licensed projects upon payment of just compensation, and take-over of such projects after the expiration of the license upon payment of the lesser of "net investment" or "fair value" of the project, in either case, plus severance damages.

The Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) and the Noxon Rapids Hydroelectric Generating Project (Noxon Rapids) are under one 45-year FERC license issued in March 2001. As part of the Clark Fork Settlement Agreement, we initiated the implementation of protection, mitigation and enhancement measures in March 1999. Measures in the agreement address issues related to fisheries, water quality, wildlife, recreation, land use, cultural resources and erosion.

See "Cabinet Gorge Total Dissolved Gas Abatement Plan" in "Note 21 of the Notes to Consolidated Financial Statements" for discussion of dissolved atmospheric gas levels that exceed state of Idaho and federal water quality standards downstream of Cabinet Gorge during periods when we must divert excess river flows over the spillway and our mitigation plans and efforts.

Five of our six hydroelectric projects on the Spokane River (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. For further information see "Spokane River Licensing" in "Note 21 of the Notes to Consolidated Financial Statements."

Future Resource Needs

We have operational strategies to provide sufficient resources to meet our energy requirements under a range of operating conditions. These operational strategies consider the amount of energy needed over 30 minute, hourly, daily, monthly and annual durations, which vary widely because of the factors that influence demand. Our average hourly load was 1,095 aMW in 2011, 1,075 aMW in 2010 and 1,082 aMW in 2009.

The following is a forecast of our average annual energy requirements and resources for 2012, 2013, 2014 and 2015:

FORECASTED ELECTRIC ENERGY REQUIREMENTS AND RESOURCES (aMW)

	2012	2013	2014	2015
Requirements:				
System load	1,113	1,134	1,150	1,165
Contracts for power sales	140	127	109	58
Total requirements	1,253	1,261	1,259	1,223
Resources:				
Company-owned and contract hydro generation (1)	542	525	527	495
Company-owned base load thermal generation (2)	511	503	507	511
Contracts for power purchases	399	440	436	432
Total resources	1,452	1,468	1,470	1,438
Surplus resources	199	207	211	215
Additional available energy (3)	152	153	153	139
Total surplus resources	351	360	364	354

(1) The forecast assumes near normal hydroelectric generation (decline in 2013 and 2015 is due to changes in contracts with PUDs).

(2) Excludes the Northeast CT and Rathdrum CT. We generally use our thermal resources to meet electric load requirements due to either below normal hydroelectric generation or increased loads or outages at other generating facilities, and/or when operating costs are lower than short-term wholesale market prices.

(3) Northeast CT and Rathdrum CT. The combined maximum capacity of the Northeast CT and Rathdrum CT is 243 MW, with estimated available energy production as indicated for each year.

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 growth in demand for energy 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 105 MW Palouse Wind, LLC project, which is expected to help meet the requirements of the Washington state Energy Independence Act beginning in 2016, as well as provide a new resource to serve our customers' increasing energy needs.
- An additional 42 aMW of wind or qualifying renewable resource or energy credits are required under the same Act beginning in 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.

We are subject to the Washington state Energy Independence Act, which includes renewable energy portfolio standards and we must obtain a portion of our electricity from qualifying renewable resources or through purchase of renewable energy credits. Future generation resource decisions will be impacted by legislation for restrictions on greenhouse gas emissions and renewable energy requirements.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Environmental Issues and Other Contingencies" for information related to existing laws, as well as potential legislation that could influence our future electric resource mix.

Natural Gas Operations

General — We provide natural gas distribution services to retail customers in parts of eastern Washington, northern Idaho, and parts of northeast and southwest Oregon.

Market prices for natural gas, like other commodities, can be volatile. To provide reliable supply and to manage the impact of volatile prices on our customers, we procure natural gas through a diversified mix of spot market purchases and forward fixed price purchases from various supply basins and over various time periods. We also use natural gas storage capacity to support high demand periods and to procure natural gas when prices may be seasonally lower. Securing prices throughout the year and even into subsequent years mitigates potential adverse impacts of significant purchase requirements in a volatile price environment.

Like prices, natural gas loads can also be volatile. Daily natural gas loads can differ significantly from the monthly load projections. We make continuing projections of our natural gas loads and assess available natural gas resources. On the basis of these projections, we plan and execute a series of transactions to hedge a significant portion of our projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend for multiple years into the future with the highest volumes hedged for the current and most immediately upcoming natural gas operating year (November through October). We also leave a significant portion of our natural gas supply requirements unhedged for purchase in short-term and spot markets.

As part of the process of balancing natural gas retail load requirements with resources, we engage in wholesale purchases and sales of natural gas. We plan for sufficient natural gas delivery capacity to serve our retail customers on a theoretical peak day. As such, we generally have more pipeline and storage capacity than what is needed. We optimize natural gas resources by using excess resources and market opportunities to generate economic value that offsets net natural gas costs. Wholesale sales are delivered through wholesale market facilities outside of our natural gas distribution system. Natural gas resource optimization activities include, but are not limited to:

- wholesale market sales of surplus natural gas supplies,
- purchases and sales of natural gas to optimize use of pipeline and storage capacity.

We also provide transportation service to certain large commercial and industrial natural gas customers who purchase natural gas through third-party marketers. For these customers, we move their natural gas through our distribution system from natural gas transmission pipeline delivery points to the customers' premises.

Natural Gas Supply — We purchase all of our natural gas in wholesale markets. We are connected to multiple supply basins in the western United States and western Canada through firm capacity delivery rights on six pipeline networks. Access to this diverse portfolio of natural gas resources allows us to make natural gas procurement decisions that benefit our natural gas customers. We have interstate pipeline capacity to serve approximately 25 percent of natural gas supplies from domestic sources, with the remaining 75 percent from Canadian sources. Natural gas prices in the Pacific Northwest are affected by global energy markets, as well as supply and demand factors in other regions of the United States and Canada. Future prices and delivery constraints may cause our source mix to vary.

Natural Gas Storage — We own a one-third interest in the Jackson Prairie Natural Gas Storage Project (Jackson Prairie), an underground natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 11.5 million therms, with a total working natural gas capacity of 253 million therms.

Avista Utilities gained 30.3 million therms of additional capacity at Jackson Prairie on May 1, 2011 for use in its utility operations. This capacity was originally held by Avista Energy and as part of the asset sales agreement this capacity had been assigned to Shell Energy through April 30, 2011.

Natural gas storage enables us to place natural gas into storage when prices may be lower or to satisfy minimum natural gas purchasing requirements, as well as to meet high demand periods or to withdraw natural gas from storage when spot prices are higher.

Regulatory Issues

General — As a regulated public utility, we are subject to regulation by state utility commissions for prices, accounting, the issuance of securities and other matters. The retail electric and natural gas operations are subject to the jurisdiction of the WUTC, the IPUC, the Public Utility Commission of Oregon (OPUC), and the Public Service Commission of the State of Montana (Montana Commission). Approval of the issuance of securities is not required from the Montana Commission. We are also subject to the jurisdiction of the FERC for licensing of hydroelectric generation resources, and for electric transmission services and wholesale sales.

Our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are determined on a "cost of service" basis. Rates are designed to provide, after recovery of allowable operating expenses, an opportunity for us to earn a reasonable return on "rate base." Rate base is generally determined by reference to the original cost (net of accumulated depreciation) of utility plant in service, subject to various adjustments for deferred taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation and retirement of utility plant and write-offs as authorized by the utility commissions. In general, a request for new rates in Washington and Idaho is made on the basis of net investment as of a date, and operating expenses and revenues for a test period ended, prior to the date of the request. Our retail revenues are derived from the number of units of electricity or natural gas actually sold and rates are based on the assumption that sales of electricity and natural gas will be the same as during the test period. Although the current ratemaking process in these states provides recovery of some future changes in net investment, operating costs and revenues, it does not reflect all changes in costs for the period in which new retail rates will be in place. This historically has resulted in a lag between the time we incur costs and the time when we start recovering the costs through subsequent changes in rates. Oregon currently allows a forecasted test year, which generally is more effective in providing timely recovery of costs.

In Washington, there is currently a proposal for an electric decoupling mechanism. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Avista Utilities — Regulatory Matters — Proposed Electric Decoupling — Washington" for further information.

Our rates for wholesale electric and natural gas transmission services are based on either "cost of service" principles or market-based rates as set forth by the FERC. See "Notes 1 and 23 of the Notes to Consolidated Financial Statements" for additional information about regulation, depreciation and deferred income taxes.

General Rate Cases — We regularly review the need for electric and natural gas rate changes in each state in which we provide service. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Avista Utilities — Regulatory Matters — General Rate Cases" for information on general rate case activity.

Power Cost Deferrals — We defer the recognition in the income statement of certain power supply costs that vary from the level currently recovered from our retail customers as authorized by the WUTC and the IPUC. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Avista Utilities — Regulatory Matters — Power Cost Deferrals and Recovery Mechanisms" and "Note 23 of the Notes to Consolidated Financial Statements" for detailed information on power cost deferrals and recovery mechanisms in Washington and Idaho.

Purchased Gas Adjustment (PGA) — Under established regulatory practices in each respective state, we are allowed to adjust natural gas rates periodically (with regulatory approval) to reflect increases or decreases in the cost of natural gas purchased. Differences between actual natural gas costs and the natural gas costs included in retail rates are deferred and charged or credited to expense when regulators approve inclusion of the cost changes in rates. We typically propose such adjustments at least once per year. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Avista Utilities — Regulatory Matters — Purchased Gas Adjustments" and "Note 23 of the Notes to Consolidated Financial Statements" for detailed information on natural gas cost deferrals and recovery mechanisms in Washington, Idaho and Oregon.

Federal Laws Related to Wholesale Competition

Federal law promotes practices that open the electric wholesale energy market to competition. The FERC requires electric utilities to transmit power and energy to or for wholesale purchasers and sellers, and requires electric utilities to enhance or construct transmission facilities to create additional transmission capacity for the purpose of providing these services. Public utilities (through subsidiaries) and other entities may participate in the development of independent electric generating plants for sales to wholesale customers.

Public utilities operating under the Federal Power Act are required to provide open and non-discriminatory access to their transmission systems to third parties and establish an Open Access Same-Time Information System to provide an electronic means by which transmission customers can obtain information about available transmission capacity and purchase transmission access. The FERC also requires each public utility subject to the rules to operate its transmission and wholesale power merchant operating functions separately and to comply with standards of conduct designed to ensure that all wholesale users, including the public utility's power merchant operations, have equal access to the public utility's transmission system. Our compliance with these standards has not had any substantive impact on the operation, maintenance and marketing of our transmission system or our ability to provide service to customers.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Competition" for further information.

Regional Transmission Organizations

Beginning with FERC Orders No. 888 and No. 2000 (issued in 2000) and continuing with subsequent rulemakings and policies (including the Variable Energy Resource Notice of Proposed Rulemaking), the FERC has encouraged better coordination and operational consistency aimed to capture efficiencies that might otherwise be gained through the formation of a Regional Transmission Organization (RTO) such as an independent system operator (ISO). While it has not mandated RTO formation, the FERC has issued orders and made public policy statements indicating its support for the development and formation of independent organizations, including those intended to implement a number of regional transmission planning coordination requirements.

We have participated in discussions with transmission providers and other stakeholders in the Pacific Northwest for several years regarding the possible formation of an ISO in the region. We ultimately became a member of ColumbiaGrid, a Washington nonprofit membership corporation with an independent slate of directors formed to improve the operational efficiency, reliability, and planned expansion of the transmission grid in the Pacific Northwest. ColumbiaGrid is not an ISO, but performs limited functions as set forth in specific agreements with ColumbiaGrid members and other stakeholders. ColumbiaGrid and its members also work with other western organizations to address operational efficiencies, including WestConnect and the Northern Tier Transmission Group. We will continue to assess the benefits of entering into other functional agreements with ColumbiaGrid and/or participating in other forums to attain operational efficiencies and to meet FERC policy objectives.

The FERC requires RTOs to provide various data and is currently requesting non-RTO regions to report similar data for the purpose of establishing performance metrics. We expect the FERC to use this data to compare RTO and non-RTO regions. We cannot foresee what policy objectives the FERC may develop as a result of establishing such performance metrics.

Reliability Standards

Among its other provisions, the U.S. Energy Policy Act provides for the implementation of mandatory reliability standards and authorizes the FERC to assess fines for non-compliance with these standards and other FERC regulations.

The FERC certified the North American Electricity Reliability Corporation (NERC) as the single Electric Reliability Organization authorized to establish and enforce reliability standards and delegate authority to regional entities for the purpose of establishing and enforcing reliability standards. The FERC has approved NERC Reliability Standards, including western region standards, making up the set of legally enforceable standards for the United States' bulk electric system. The first of these reliability standards became effective in June 2007. We are required to self-certify our compliance with these standards on an annual basis and undergo regularly scheduled periodic reviews by the NERC and its regional entity, the Western Electricity Coordinating Council (WECC). Our failure to comply with these standards could result in financial penalties of up to $1 million per day per violation. Annual self-certification and audit processes to date have demonstrated our substantial compliance with these standards.

Avista Utilities Operating Statistics
Years Ended December 31,

	2011	2010	2009
Electric Operations			
Electric Operating Revenues (Dollars in Thousands):			
Residential	$ 324,835	$ 296,627	$ 315,649
Commercial	280,139	265,219	273,954
Industrial	122,560	114,792	107,741
Public street and highway lighting	6,941	6,702	6,607
Total retail	734,475	683,340	703,951
Wholesale	78,305	165,553	88,414
Sales of fuel	153,470	106,375	32,992
Other	21,937	19,015	15,426
Total electric operating revenues	$ 988,187	$ 974,283	$ 840,783
Electric Energy Sales (Thousands of MWhs):			
Residential	3,728	3,618	3,791
Commercial	3,122	3,100	3,177
Industrial	2,147	2,099	1,948
Public street and highway lighting	26	26	26
Total retail	9,023	8,843	8,942
Wholesale	2,796	3,803	2,354
Total electric energy sales	11,819	12,646	11,296
Electric Energy Resources (Thousands of MWhs):			
Hydro generation (from Company facilities)	4,534	3,494	3,766
Thermal generation (from Company facilities)	2,447	3,748	3,097
Purchased power — hydro generation from long-term contracts with PUDs	1,047	685	839
Purchased power — wholesale	4,388	5,315	4,152
Power exchanges	(24)	(15)	(18)
Total power resources	12,392	13,227	11,836
Energy losses and Company use	(573)	(581)	(540)
Total energy resources (net of losses)	11,819	12,646	11,296
Number of Electric Retail Customers (Average for Period):			
Residential	316,762	315,283	313,884
Commercial	39,618	39,489	39,276
Industrial	1,380	1,376	1,394
Public street and highway lighting	455	449	444
Total electric retail customers	358,215	356,597	354,998
Electric Residential Service Averages:			
Annual use per customer (kWh)	11,769	11,476	12,079
Revenue per kWh (in cents)	8.71	8.20	8.33
Annual revenue per customer	$ 1,025.48	$ 940.83	$ 1,005.62
Electric Average Hourly Load (aMW)	1,096	1,075	1,082

Avista Utilities Operating Statistics

Years Ended December 31,

	2011	2010	2009
Electric Operations (continued):			
Resource Availability at time of system peak (MW):			
Total requirements (winter):			
Retail native load	1,669	1,704	1,763
Wholesale obligations	712	803	608
Total requirements (winter)	2,381	2,507	2,371
Total resource availability (winter)	2,923	2,905	2,514
Total requirements (summer):			
Retail native load	1,535	1,556	1,522
Wholesale obligations	472	822	685
Total requirements (summer)	2,007	2,378	2,207
Total resource availability (summer)	2,370	2,662	2,499
Cooling Degree Days: (1)			
Spokane, WA			
Actual	426	380	589
30-year average	434	434	394
% of average	98%	88%	149%

(1) Cooling degree days are the measure of the warmness of weather experienced, based on the extent to which the average of high and low temperatures for a day exceeds 65 degrees Fahrenheit (annual degree days above historic indicate warmer than average temperatures).

Avista Utilities Operating Statistics

Years Ended December 31,

	2011	2010	2009
Natural Gas Operations			
Natural Gas Operating Revenues (Dollars in Thousands):			
Residential	$ 219,557	$ 193,169	$ 251,022
Commercial	111,964	98,257	135,236
Industrial and interruptible	6,699	6,494	9,945
Total retail	338,220	297,920	396,203
Wholesale	195,882	197,364	143,524
Transportation	6,709	6,470	6,067
Other	7,414	9,495	8,624
Total natural gas operating revenues	$ 548,225	$ 511,249	$ 554,418
Therms Delivered (Thousands of Therms):			
Residential	207,202	188,546	207,979
Commercial	125,344	113,422	126,345
Industrial and interruptible	10,157	9,755	10,918
Total retail	342,703	311,723	345,242
Wholesale	510,755	468,887	397,977
Transportation	152,515	142,093	144,580
Interdepartmental and Company use	440	393	502
Total therms delivered	1,006,413	923,096	888,301
Sources of Natural Gas Delivered (Thousands of Therms):			
Purchases	877,290	787,836	751,057
Storage — injections	(109,782)	(86,750)	(99,330)
Storage — withdrawals	94,504	83,333	95,183
Natural gas for transportation	152,515	142,093	144,580
Distribution system losses	(8,114)	(3,416)	(3,189)
Total natural gas delivered	1,006,413	923,096	888,301
Number of Natural Gas Retail Customers (Average for Period):			
Residential	284,504	282,721	280,667
Commercial	33,540	33,431	33,214
Industrial and interruptible	293	292	300
Total natural gas retail customers	318,337	316,444	314,181
Natural Gas Residential Service Averages:			
Annual use per customer (therms)	728	667	741
Revenue per therm (in dollars)	$ 1.06	$ 1.02	$ 1.21
Annual revenue per customer	$ 771.72	$ 683.25	$ 894.37
Heating Degree Days: (1)			
Spokane, WA			
Actual	6,861	6,320	6,976
30-year average	6,647	6,647	6,820
% of average	103%	95%	102%
Medford, OR			
Actual	4,634	4,119	4,485
30-year average	4,402	4,402	4,533
% of average	105%	94%	99%

(1) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual degree days below historic indicate warmer than average temperatures).

ECOVA (FORMERLY KNOWN AS ADVANTAGE IQ)

In October 2011, our subsidiary, Advantage IQ changed its name to Ecova, which combined the company and its subsidiary Ecos under one name and brand. Ecova provides sustainable utility expense management and energy management solutions to multi-site companies across North America. Ecova's invoice processing, auditing and payment services, coupled with energy procurement, comprehensive reporting and advanced analysis, provide the critical data clients need to balance the financial, social and environmental aspects of doing business.

As part of the expense management services, Ecova analyzes and audits invoices, then presents consolidated bills on-line, and processes payments. Information gathered from invoices, providers and other customer-specific data allows Ecova to provide its clients with in-depth analytical support, real-time reporting and consulting services.

Ecova also provides comprehensive energy efficiency program management services to utilities across North America. As part of these management services, Ecova helps utilities develop and execute energy efficiency programs with a complete turn-key solution.

Ecova has secured five patents on its two critical business systems:

- Facility IQ™ system, which provides operational information drawn from facility bills, and
- AviTrack™ database, which processes and reports on information gathered from service providers to ensure that customers are receiving the most effective services at the proper price.

We are not aware of potential infringement of any of Ecova's patents issued to date and we expect to continue to expand and protect existing patents, as well as file additional patent applications for new products, services and process enhancements. Furthermore, we are not aware of any claims or threatened claims that Ecova has infringed any patents held by other parties.

The following table presents key statistics for Ecova:

	2011	2010	2009
Expense management customers at year-end	645	534	532
Billed sites at year-end	496,842	360,596	421,080
Dollars of customer bills processed (in billions)	$ 18.3	$ 17.3	$ 17.4

The decrease in billed sites at year-end 2010 as compared to 2009 was due to the loss of a customer that had a significant number of billed sites, but represented only approximately 1 percent of annual revenues. On December 31, 2010, Ecova acquired The Loyalton Group, a Minneapolis-based energy management firm known for its energy procurement and price risk management solutions. In January 2011, Ecova acquired Building Knowledge Networks, a Seattle-based real-time building energy management services provider. In November 2011, Ecova acquired Prenova, an energy management company headquartered in Atlanta, Georgia. In January 2012, Ecova acquired LPB Energy Management (LPB), an energy management company headquartered in Dallas, Texas.

The noncontrolling interest of Ecova (which was 20.8 percent as of December 31, 2011) is primarily held by the previous owners of Cadence Network, a company acquired by Ecova in 2008.

OTHER BUSINESSES

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.

Our other businesses also include Advanced Manufacturing and Development (AM&D) doing business as METALfx, a subsidiary that performs custom sheet metal fabrication of electronic enclosures, parts and systems for the computer, telecom, renewable energy and medical industries. Our other investments and operations include:

- real estate investments (primarily commercial office buildings),
- investments in emerging technology venture capital funds, and
- the remaining investment in a fuel cell business that was previously a subsidiary of the Company.

Over time as opportunities arise, we dispose of assets and phase out operations that do not fit with our overall corporate strategy. However, we may invest incremental funds to protect our existing investments and invest in new businesses that fit with our overall corporate strategy.

ITEM 1A. RISK FACTORS

RISK FACTORS

The following factors could have a significant impact on our operations, results of operations, financial condition or cash flows. These factors could cause actual results or outcomes to differ materially from those discussed in our reports filed with the Securities and Exchange Commission (including this Annual Report on Form 10-K), and elsewhere. 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.

Weather (temperatures, precipitation levels and storms) has a significant effect on our results of operations, financial condition and cash flows.

Weather impacts are described in the following subtopics:

- retail electricity and natural gas sales,
- the cost of natural gas supply,
- the cost of power supply, and
- damages to facilities.

Retail electricity and natural gas sales volumes vary directly with changes in temperatures. We normally have our highest retail (electric and natural gas) energy sales during the winter heating season in the first and fourth quarters of the year. We also have high electricity demand for air conditioning during the summer (third quarter). In general, warmer weather in the heating season and cooler weather in the cooling season will reduce our customers' energy demand and retail operating revenues.

The cost of natural gas supply tends to increase with increased demand during periods of cold weather. Increased costs adversely affect cash flows when we purchase natural gas for retail supply at prices above the amount then allowed for recovery in retail rates. We defer differences between actual natural gas supply costs and the amount currently recovered in retail rates and we have generally been allowed to recover substantially all of these differences after regulatory review. However, these deferred costs require cash outflows from the time of natural gas purchases until the costs are later recovered through retail sales.

The cost of power supply can be significantly impacted by weather. Precipitation (consisting of snowpack, its water content and melting pattern plus rainfall) and other streamflow conditions (such as regional water storage operations) significantly affect hydroelectric generation capability. Variations in hydroelectric generation inversely affect our reliance on market purchases and thermal generation. To the extent that hydroelectric generation is less than normal, significantly more costly power supply resources must be acquired and the ability to realize net benefits from surplus hydroelectric wholesale sales is reduced. Wholesale prices also vary to a greater extent each year based on wind patterns as wind generation facilities have grown significantly in the region.

The price of power in the wholesale energy markets tends to be higher during periods of high regional demand, such as occurs with temperature extremes. We may need to purchase power in the wholesale market during peak price periods. The price of natural gas as fuel for natural gas-fired electric generation also tends to increase during periods of high demand which are often related to temperature extremes. We may need to purchase natural gas fuel in these periods of high prices to meet electric demands. The cost of power supply during peak usage periods may be higher than the retail sales price or the amount allowed in retail rates by our regulators. To the extent that power supply costs are above the amount allowed currently in retail rates, the difference is partially absorbed by the Company in current expense and it is partially deferred or shared with customers through regulatory mechanisms. Therefore, the impact on our results of operations may be larger or smaller than the weather-related impact on power supply cost.

As a result of these factors operating in combination, our net cost of power supply — the difference between our costs of generation and market purchases, reduced by our revenue from wholesale sales — varies significantly because of weather.

Damages to facilities may be caused by severe weather, such as snow, ice or wind storms. The cost to implement rapid repair to such facilities can be significant. Overhead electric lines are most susceptible to such severe weather. Collateral damage from utility assets that are damaged by external forces may result in third party claims against the Company for property damage and/or personal injuries.

We are subject to commodity price risk.

A combination of factors exposes our operations to commodity price risks. We rely on energy markets and other counterparties for energy supply, surplus and optimization transactions and commodity price hedging. These factors include:

- Our obligation to serve our retail customers at rates set through the regulatory process. We cannot change retail rates to reflect current energy prices unless and until we receive regulatory approval.
- Customer demand, which is beyond our control because of weather, customer choices, prevailing economic conditions and other factors.
- Some of our energy supply cost is fixed by nature of the energy-producing assets or through contractual arrangements. However, a significant portion of our energy resource costs are not fixed.

Because we must supply the amount of energy demanded by our customers and we must sell it at fixed rates and only a portion of our energy supply costs are fixed, we are subject to the risk of buying energy at higher prices in wholesale energy markets (and the risk of selling energy at lower prices if we are in a surplus position). Electricity and natural gas in wholesale markets are commodities with historically high price volatility. Changes in wholesale energy prices affect, among other things, the cash requirements to purchase electricity and natural gas for retail customers or wholesale obligations and the market value of derivative assets and liabilities.

When we enter into fixed price energy commodity transactions for future delivery, we are subject to credit terms that may require us to provide collateral to wholesale counterparties related to the difference between current prices and the agreed upon fixed prices. These collateral requirements can place significant demands on our cash flows or borrowing arrangements. Price volatility can cause collateral requirements to change quickly and significantly.

Regulators may not grant rates that provide timely or sufficient recovery of our costs or allow a reasonable rate of return for our shareholders.

We have experienced higher costs for utility operations in each of the last several years. We have also made significant capital investments into utility plant assets. Our ability to recover these costs depends on the amount and timeliness of retail rate changes allowed by regulatory agencies. We expect to periodically file for rate increases with regulatory agencies to recover our costs and provide an opportunity to earn a reasonable return for shareholders. If regulators grant substantially lower rate increases than our requests in the future or if deferred costs are disallowed, it could have a negative effect on our operating revenues, net income and cash flows.

Deferred power and natural gas costs are subject to regulatory review; costs higher than those recovered in retail rates reduce cash flows.

We defer income statement recognition and recovery from customers of certain power and natural gas costs that are higher than what is currently authorized in retail rates by regulators. These power and natural gas costs are recorded as deferred charges with the opportunity for future recovery through retail rates. These deferred costs are subject to review for prudence and potential disallowance by regulators.

Despite the opportunity to recover deferred power and natural gas costs, our operating cash flows are negatively affected until these costs are recovered from customers.

Our energy resource management activities may cause volatility in our cash flows and results of operations.

We engage in active hedging and resource optimization practices; however, we cannot and do not attempt to fully hedge our energy resource assets or our forecasted net positions for various time horizons. To reduce energy cost volatility and economic exposure related to commodity price fluctuations, we routinely enter into contracts to hedge a portion of our purchase and sale commitments for electricity and natural gas, as well as forecasted excess or deficit energy positions and inventories of natural gas. We use physical energy contracts and derivative instruments, such as forwards, futures, swaps and options traded in the over-the-counter markets or on exchanges. We do not cover the entire market price volatility exposure for our forecasted net positions. To the extent we have positions that are not hedged, or if hedging positions do not fully match the corresponding purchase or sale, fluctuating commodity prices could have a material effect on our operating revenues, resource costs, derivative assets and liabilities, and operating cash flows. In addition, actual loads and resources typically vary from forecasts, sometimes to a significant degree, which requires additional transactions or dispatch decisions that impact cash flows.

Financial market conditions may impact our results of operations and our liquidity.

We have significant capital requirements that we expect to fund, in part, by accessing capital markets. As such, the state of financial markets and credit availability in the global, United States and regional economies could have an impact on our operations. We could experience increased borrowing costs or limited access to capital on reasonable terms.

We need to access long-term capital markets to finance capital expenditures, repay maturing long-term debt and obtain additional working capital from time to time. Our ability to access capital on reasonable terms is subject to numerous factors and market conditions, many of which are beyond our control. If we are unable to obtain capital on reasonable terms, it may limit or prohibit 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.

Performance of the financial markets could also result in significant declines in the market values of assets held by our pension plan and/or a significant increase in the pension liability (which impacts the funded status of the plan) and could increase future funding obligations and pension expense.

We rely on access to credit from financial institutions for short-term borrowings.

We need to maintain access to adequate levels of credit with financial institutions for short-term liquidity. We have a $400 million committed line of credit, which is scheduled to expire in February 2017. We cannot guarantee that we will have access to credit beyond the expiration date. The committed line of credit agreement contains customary covenants and default provisions. In the event of 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.

Ecova has a $60 million committed line of credit, which is scheduled to expire in April 2014. In accordance with the agreement, the amount of this credit facility will be reduced to $55 million on September 30, 2012 and $50 million on December 31, 2012. Following the acquisition of LPB in January 2012, this credit agreement is fully utilized. Ecova expects to expand this facility in 2012. However, we cannot guarantee that Ecova will be able to expand this facility or have access to credit beyond the expiration date.

Downgrades in our credit ratings could limit our ability to obtain financing, adversely affect the terms of financing and impact our ability to transact for or hedge energy resources.

If we do not maintain our investment grade credit rating with the major credit rating agencies, we could expect increased debt service costs, limitations on our ability to access capital markets or obtain other financing on reasonable terms, and requirements to provide collateral (in the form of cash or letters of credit) to lenders and counterparties. In addition, credit rating downgrades could reduce the number of counterparties willing to do business with us.

We are subject to various operational and event risks that are associated with the utility industry.

Our utility operations are subject to operational and event risks that include:

- blackouts or disruptions to distribution, transmission or transportation systems,
- forced outages at generating plants,
- fuel cost and availability, including delivery constraints,
- explosions, fires, accidents, or mechanical breakdowns that may occur while operating and maintaining our generation, transmission and distribution systems, and
- natural disasters that can disrupt energy generation, transmission and distribution.

As protection against operational and event risks, we maintain insurance coverage against some, but not all, potential losses and we seek to negotiate indemnification arrangements with contractors for certain event risks. However, insurance or indemnification agreements may not be adequate to protect us against liability from all of the operational and event risks described above. In addition, we are subject to the risk that insurers and/or other parties will dispute or be unable to perform on their obligations to us.

Cyber security attacks, terrorism or other malicious acts could disrupt our business and have a negative impact on our results of operations and cash flows.

In the course of our operations, we rely on interconnected information technology systems for operation of our generating plants, electric transmission and distribution systems, natural gas distribution, customer billing and customer service, accounting and other administrative processes and compliance with various regulations. There are various risks associated with information technology systems such as hardware or software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other deliberate or inadvertent human errors. In particular, cyber security attacks, terrorism or other malicious acts could damage, destroy or disrupt these systems. Any failure of information technology systems could result in a loss of operating revenues, an increase in operating expenses and costs to repair or replace damaged assets. Any of the above could also result in the loss or release of confidential customer information or other proprietary data that could adversely affect our reputation and result in costly litigation. As these potential cyber security attacks become more common and sophisticated, we could be required to incur costs to strengthen our systems or obtain specific insurance coverage against potential losses.

We are currently the subject of several regulatory proceedings, and we are named in multiple lawsuits related to our participation in western energy markets.

Through our utility operations and the prior operations of Avista Energy, we are involved in a number of legal and regulatory proceedings and complaints related to energy markets in the western United States. Most of these proceedings and complaints relate to the significant increase in the spot market price of energy in 2000 and 2001. This allegedly contributed to or caused unjust and unreasonable prices. These proceedings and complaints include, but are not limited to:

- refund proceedings in California and the Pacific Northwest,
- market conduct investigations by the FERC, and
- complaints filed by various parties related to alleged misconduct by parties in western power markets.

As a result of these proceedings and complaints, certain parties have asserted claims for significant refunds and damages from us, which could result in a negative effect on our results of operations and cash flows. See "Note 21 of the Notes to Consolidated Financial Statements" for further information.

We are subject to legislation and related administrative rulemaking, including periodic audits of compliance with such rules, which may adversely affect our operational and financial performance.

We expect to continue to be affected by legislation at the national, state and local level, as well as by administrative rules and requirements published by government agencies, including but not limited to the FERC, the EPA and state regulators. We are also subject to NERC and WECC reliability standards. The FERC, the NERC and the WECC may perform periodic audits of the Company. Failure to comply with the FERC, the NERC, or the WECC requirements can result in financial penalties of up to $1 million per day per violation.

Future legislation or administrative rules could have a material adverse effect on our operations, results of operations, financial condition and cash flows.

Concerns over long-term global climate changes may affect our operational and financial performance.

Legislative developments and advocacy at the state, national and international levels about climate change and other environmental concerns may have significant impacts on our operations. The electric utility industry is one of the largest and most immediate industries to be more heavily regulated in some proposals. For example, various legislative proposals have been made to limit or place further restrictions on byproducts of combustion, including sulfur dioxide, nitrogen oxide, carbon dioxide, and other greenhouse gases and mercury emissions. Such proposals, if adopted, could restrict the operation and raise the cost of our power generation resources.

We expect continuing activity in the future and we are evaluating the extent that potential changes to environmental laws and regulations may:

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

We have contingent liabilities, including certain matters related to potential environmental liabilities, and cannot predict the outcome of these matters.

In the normal course of our business, we have matters that are the subject of ongoing litigation, mediation, investigation and/or negotiation. We cannot predict the ultimate outcome or potential impact of any particular issue, including the extent, if any, of insurance coverage or that amounts payable by us may be recoverable through the ratemaking process. We are subject to environmental regulation by federal, state and local authorities related to our past, present and future operations. See “Note 21 of the Notes to Consolidated Financial Statements” for further details of these matters including:

- alleged contamination from the holding ponds at Colstrip in Montana,
- waste oil delivered to the Harbor Oil, Inc. site in Portland, Oregon, and
- aluminum dross located on a parcel of land we own near the Spokane River.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As of the filing date of this Annual Report on Form 10-K, we have no unresolved comments from the staff of the Securities and Exchange Commission.

ITEM 2. PROPERTIES

AVISTA UTILITIES

Substantially all of our utility properties are subject to the lien of our mortgage indenture.

Our utility electric properties, located in the states of Washington, Idaho, Montana and Oregon, include the following:

GENERATION PROPERTIES

	No. of Units	Nameplate Rating (MW) (1)	Present Capability (MW) (2)
Hydroelectric Generating Stations (River)			
Washington:			
Long Lake (Spokane)	4	70.0	87.0
Little Falls (Spokane)	4	32.0	34.6
Nine Mile (Spokane)	3	26.4	17.6
Upper Falls (Spokane)	1	10.0	10.2
Monroe Street (Spokane)	1	14.8	15.0
Idaho:			
Cabinet Gorge (Clark Fork) (3)	4	265.0	254.6
Post Falls (Spokane)	6	14.8	18.0
Montana:			
Noxon Rapids (Clark Fork)	5	480.6	562.4
Total Hydroelectric		913.6	999.4
Thermal Generating Stations			
Washington:			
Kettle Falls GS	1	50.7	50.0
Kettle Falls CT	1	7.2	6.9
Northeast CT	2	61.8	61.2
Boulder Park	6	24.6	24.0
Idaho:			
Rathdrum CT	2	166.5	149.0
Montana:			
Colstrip Units 3 and 4 (4)	2	233.4	222.0
Oregon:			
Coyote Springs 2	1	287.0	278.3
Total Thermal		831.2	791.4
Total Generation Properties		1,744.8	1,790.8

(1) Nameplate Rating, also referred to as "installed capacity," is the manufacturer's assigned power capability under specified conditions.

(2) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions. Information is provided as of December 31, 2011.

(3) The present capability of Cabinet Gorge is limited by our water rights. This output level reflects the maximum capability within our water rights. When river flows exceed these water rights limits, we are permitted to increase flow through the plant resulting in up to 265 MW.

(4) Jointly owned; data refers to our 15 percent interest.

Electric Distribution and Transmission Plant

We operate approximately 18,300 miles of primary and secondary electric distribution lines providing service to retail customers. We have an electric transmission system of 685 miles of 230 kV line and 1,535 miles of 115 kV line. We also own an 11 percent interest in approximately 500 miles of a 500 kV line between Colstrip, Montana and Townsend, Montana. Our transmission and distribution systems also include numerous substations with transformers, switches, monitoring and metering devices, and other equipment.

The 230 kV lines are the backbone of our transmission grid and are used to transmit power from generation resources, including Noxon Rapids, Cabinet Gorge and the Mid-Columbia hydroelectric projects, to the major load centers in our service area, as well as to transfer power between points of interconnection with adjoining electric transmission systems. These lines interconnect at various locations with the Bonneville Power Administration (BPA), Grant County PUD, PacifiCorp, NorthWestern Energy and Idaho Power Company and serve as points of delivery for power from generating facilities outside of our service area, including Colstrip, Coyote Springs 2 and the Lancaster Plant.

These lines also provide a means for us to optimize resources by entering into short-term purchases and sales of power with entities within and outside of the Pacific Northwest.

The 115 kV lines provide for transmission of energy and the integration of smaller generation facilities with our service-area load centers, including the Spokane River hydroelectric projects, the Kettle Falls projects, Rathdrum CT, Boulder Park and the Northeast CT. These lines interconnect with the BPA, Chelan County PUD, the Grand Coulee Project Hydroelectric Authority, Grant County PUD, NorthWestern Energy, PacifiCorp and Pend Oreille County PUD. Both the 115 kV and 230 kV interconnections with the BPA are used to transfer energy to facilitate service to each other's customers that are connected through the other's transmission system. We hold a long-term transmission agreement with the BPA that allows us to serve our native load customers that are connected through the BPA's transmission system.

Natural Gas Plant

We have natural gas distribution mains of approximately 3,400 miles in Washington, 1,950 miles in Idaho and 2,300 miles in Oregon. We have natural gas transmission mains of approximately 75 miles in Washington and 40 miles in Oregon. Our natural gas system includes numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment.

We own a one-third interest in the Jackson Prairie Natural Gas Storage Project (Jackson Prairie), an underground natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 11.5 million therms, with a total working natural gas capacity of 253 million therms. Natural gas storage enables us to place natural gas into storage when prices are lower or to satisfy minimum natural gas purchasing requirements, as well as to meet high demand periods or to withdraw natural gas from storage when spot prices are higher.

Avista Utilities gained 30.3 million therms of additional capacity at Jackson Prairie on May 1, 2011 for use in its utility operations. This capacity was originally held by Avista Energy and as part of the asset sales agreement this capacity had been assigned to Shell Energy through April 30, 2011.

ITEM 3. LEGAL PROCEEDINGS

See "Note 21 of Notes to Consolidated Financial Statements" for information with respect to legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is currently listed on the New York Stock Exchange under the ticker symbol "AVA". As of January 31, 2012, there were 10,693 registered shareholders of our common stock.

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 generally derived from our regulated utility operations.

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

On February 3, 2012, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.29 per share on the Company's common stock. This was an increase of $0.015 per share, or 5 percent from the previous quarterly dividend of $0.275 per share.

For additional information, refer to "Notes 1, 18, 19 and 20 of Notes to Consolidated Financial Statements."

The following table presents quarterly high and low stock prices as reported on the consolidated reporting system, as well as dividend information:

	Three Months Ended			
	March 31	**June 30**	**September 30**	**December 31**
2011				
Dividends paid per common share	$ 0.275	$ 0.275	$ 0.275	$ 0.275
Trading price range per common share:				
High	$ 23.69	$ 25.83	$ 26.53	$ 26.35
Low	$ 21.78	$ 22.81	$ 21.13	$ 23.14
2010				
Dividends paid per common share	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Trading price range per common share:				
High	$ 22.37	$ 22.25	$ 21.88	$ 22.81
Low	$ 19.19	$ 18.46	$ 19.05	$ 20.90

For information with respect to securities authorized for issuance under equity compensation plans, see "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters."

ITEM 6.

SELECTED FINANCIAL DATA

Avista Corporation

(in thousands, except per share data and ratios)

Years Ended December 31,

	2011	2010	2009	2008	2007
Operating Revenues:					
Avista Utilities	$ 1,443,322	$ 1,419,646	$ 1,395,201	$ 1,572,664	$ 1,288,363
Ecova	137,848	102,035	77,275	59,085	47,255
Other	40,410	61,067	40,089	45,014	82,139
Intersegment eliminations	(1,800)	(24,008)	—	—	—
Total	$ 1,619,780	$ 1,558,740	$ 1,512,565	$ 1,676,763	$ 1,417,757
Income (Loss) from Operations (pre-tax):					
Avista Utilities	$ 208,970	$ 208,104	$ 195,389	$ 174,245	$ 150,053
Ecova	20,917	15,865	11,603	11,297	11,012
Other	5,735	6,219	(6,334)	(631)	(22,636)
Total	$ 235,622	$ 230,188	$ 200,658	$ 184,911	$ 138,429
Net income	$ 103,539	$ 94,948	$ 88,648	$ 74,757	$ 38,727
Net income attributable to noncontrolling interests	$ (3,315)	$ (2,523)	$ (1,577)	$ (1,137)	$ (252)
Net Income (Loss) Attributable to Avista Corporation:					
Avista Utilities	$ 90,902	$ 86,681	$ 86,744	$ 70,032	$ 43,822
Ecova	9,671	7,433	5,329	6,090	6,651
Other	(349)	(1,689)	(5,002)	(2,502)	(11,998)
Total	$ 100,224	$ 92,425	$ 87,071	$ 73,620	$ 38,475
Average common shares outstanding, basic	57,872	55,595	54,694	53,637	52,796
Average common shares outstanding, diluted	58,092	55,824	54,942	54,028	53,263
Common shares outstanding at year-end	58,423	57,120	54,837	54,488	52,909
Earnings per Common Share Attributable to Avista Corporation:					
Diluted	$ 1.72	$ 1.65	$ 1.58	$ 1.36	$ 0.72
Basic	$ 1.73	$ 1.66	$ 1.59	$ 1.37	$ 0.73
Dividends paid per common share	$ 1.10	$ 1.00	$ 0.81	$ 0.69	$ 0.595
Book value per common share at year-end	$ 20.30	$ 19.71	$ 19.17	$ 18.30	$ 17.27
Total Assets at Year-End:					
Avista Utilities	$ 3,809,446	$ 3,589,235	$ 3,400,384	$ 3,434,844	$ 3,009,499
Ecova	292,940	221,086	143,060	125,911	108,929
Other	112,145	129,774	63,515	69,992	71,369
Total	$ 4,214,531	$ 3,940,095	$ 3,606,959	$ 3,630,747	$ 3,189,797
Long-Term Debt (including current portion)	$ 1,177,300	$ 1,101,857	$ 1,071,338	$ 826,465	$ 948,833
Nonrecourse Long-Term Debt of Spokane Energy (including current portion) (1)	$ 46,471	$ 58,934	$ —	$ —	$ —
Long-Term Debt to Affiliated Trusts	$ 51,547	$ 51,547	$ 51,547	$ 113,403	$ 113,403
Total Avista Corporation Stockholders' Equity	$ 1,185,701	$ 1,125,784	$ 1,051,287	$ 996,883	$ 913,966
Ratio of Earnings to Fixed Charges (2)	3.06	2.86	2.95	2.43	1.67

(1) Spokane Energy was consolidated effective January 1, 2010. See Note 3 of the Notes to Consolidated Financial Statements.

(2) See Exhibit 12 for computations.

ITEM 7. 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 known as Advantage IQ)** — an indirect subsidiary of Avista Corp. (79.2 percent owned as of December 31, 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 and telecom 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 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 year ended December 31 (dollars in thousands):

	2011	2010	2009
Avista Utilities	$ 90,902	$ 86,681	$ 86,744
Ecova	9,671	7,433	5,329
Other	(349)	(1,689)	(5,002)
Net income attributable to Avista Corporation	$ 100,224	$ 92,425	$ 87,071

EXECUTIVE LEVEL SUMMARY

Overall

Net income attributable to Avista Corporation was $100.2 million for 2011, an increase from $92.4 million for 2010. This was primarily due to an increase in earnings at Avista Utilities (primarily due to colder weather during the first quarter 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, as well as a reduction in the net loss from the Other businesses. The first quarter of 2011 was significantly colder than the first quarter of 2010 and slightly colder than average. The first quarter of 2010 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.

In our utility operations, we regularly review the need for rate changes in each jurisdiction to improve the recovery of costs and capital investments in our generation, transmission and distribution systems. General rate increases went into effect in Idaho on October 1, 2010 and October 1, 2011, in Washington effective December 1, 2010 and January 1, 2012, and in Oregon effective March 15, 2011 and June 1, 2011.

Our utility net income was $90.9 million for 2011, an increase from $86.7 million for 2010. Earnings for 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 first quarter and 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 costs, pensions and other postretirement benefits expense, and labor costs.

Above normal snowpack last winter, and a cool and wet spring produced excellent river run-off conditions in 2011. This resulted in one of the best hydroelectric generation years on record. In addition, purchased power and natural gas fuel prices were below the level included in base rates. As such, the Company received a benefit of $6.4 million and $12.9 million was deferred for the future benefit of customers under the Energy Recovery Mechanism in Washington.

We are making significant capital investments in generation, transmission and distribution systems to preserve and enhance service reliability for our customers and replace aging infrastructure. Utility capital expenditures were $239.8 million for 2011. We expect utility capital expenditures to be about $250 million for each of 2012 and 2013. These estimates of capital expenditures are subject to continuing review and adjustment (see discussion under "Avista Utilities Capital Expenditures").

Ecova

Ecova had net income attributable to Avista Corporation of $9.7 million for 2011, an increase from $7.4 million for 2010. This increase 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. Ecova's earnings potential continues to be moderated by low short-term interest rates, which limits interest revenue on funds held for clients.

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

In January 2012, Ecova acquired LPB Energy Management (LPB), a Dallas-based energy management company. The cash paid for the acquisition of LPB of $50.3 million was funded by Ecova through $25.0 million of borrowings under its committed credit agreement, a $20.0 million equity infusion from existing shareholders (including Avista Capital and the other owners of Ecova), and available cash.

While we do not expect these acquisitions to have an impact on 2012 earnings, they increase Ecova's market share and allow Ecova to offer its clients a broader range of services leading to potential future earnings growth.

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. These 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 December 31, 2011, there were redeemable noncontrolling interests of $38.9 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.

Other Businesses

The net loss for these operations was $0.3 million for 2011 compared to a net loss of $1.7 million for 2010. The improvement in results was due in part to increased earnings at METALfx and a decrease in the net loss on investments. Also, in 2010, we recorded a $2.2 million impairment of our investment in a fuel cell business.

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.

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. In December 2011, this committed line of credit was amended to extend the expiration date to February 2017 and improve the pricing terms. As of December 31, 2011, there were $61.0 million of cash borrowings and $29.0 million in letters of credit outstanding. As of December 31, 2011, we had $310.0 million of available liquidity under this line of credit.

In December 2011, we issued $85.0 million of 4.45 percent First Mortgage Bonds due in 2041. The net proceeds from the sale of the bonds were used to repay a portion of the borrowings outstanding under our $400.0 million committed line of credit. We expect to issue up to $100.0 million of long-term debt in 2012.

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 (included as part of long-term debt) is amortized as a component of interest expense over the life of the forecasted interest payments.

In 2011, we issued $26.5 million of common stock, including $19.5 million under a sales agency agreement.

We expect to issue up to $45 million of common stock from time to time in 2012 in order to maintain our capital structure at an appropriate level for our business. We have 0.2 million shares available to be issued under the sales agency agreement and we expect to expand this agreement for a significant portion of our 2012 common stock issuances. After considering the issuances of long-term debt and common stock during 2012, we expect net cash flows from operating activities, together with cash available under our $400.0 million committed line of credit agreement, to provide adequate resources to fund:

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

AVISTA UTILITIES — REGULATORY MATTERS

General Rate Cases

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

- provide for recovery of operating costs and capital investments, and
- provide the opportunity to improve our earned returns as allowed by regulators.

With regards to the timing and plans for future filings, the assessment of our need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include, but are not limited to, in-service dates of major capital investments and the timing of changes in major revenue and expense items. We filed general rate cases in Washington in May 2011 (which was settled with new rates effective January 1, 2012) and in Idaho in July 2011 (which was settled with new rates effective October 1, 2011).

We expect to file general rate cases in Washington in the second quarter of 2012 and in Idaho in the second half of 2012.

Washington General Rate Cases

In December 2009, the WUTC issued an order in our electric and natural gas general rate cases that were filed with the WUTC in January 2009. The WUTC approved a base electric rate increase for our Washington customers of 2.8 percent, which was designed to increase annual revenues by $12.1 million. Base natural gas rates for our Washington customers increased by an average of 0.3 percent, which was designed to increase annual revenues by $0.6 million. The new electric and natural gas rates became effective on January 1, 2010.

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.

In December 2011, the WUTC approved a settlement agreement in our electric and natural gas general rate cases filed in May 2011. As agreed to in the settlement agreement, base electric rates for our Washington customers increased by an average of 4.6 percent, which is designed to increase annual revenues by $20.0 million. Base natural gas rates for our Washington customers increased by an average of 2.4 percent, which is designed to increase annual revenues by $3.75 million. The new electric and natural gas rates became effective on January 1, 2012. No capital structure ratios or cost of capital components were specified in the settlement agreement. 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 are deferring 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 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 will occur annually, with no carrying charge, with deferred costs being amortized over a four-year period, beginning in the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases would be the actual maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. For 2011, we deferred $0.5 million of maintenance costs in Washington.

Idaho General Rate Cases

In July 2009, the IPUC approved a settlement agreement in our general rate cases that were filed with the IPUC in January 2009. The new electric and natural gas rates became effective on August 1, 2009. As agreed to in the settlement, base electric rates for our Idaho customers increased by an average of 5.7 percent, which was designed to increase annual revenues by $12.5 million. Base natural gas rates for our Idaho customers increased by an average of 2.1 percent, which was designed to increase annual revenues by $1.9 million.

In September 2010, the IPUC approved a settlement agreement with respect to 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 was 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 agreement, base electric rates for our Idaho customers increased by an average of 1.1 percent, which is designed to increase annual revenues by $2.8 million. Base natural gas rates for our Idaho customers increased by an average of 1.6 percent, which is designed to increase annual revenues by $1.1 million.

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

The settlement agreement also provides for the deferral of certain generation plant operation and maintenance costs. In order to address the variability in year-to-year operation and maintenance costs, beginning in 2011, we are deferring 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 compare actual, non-fuel, operation and maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of expenses authorized for recovery in base rates in the applicable deferral year, and defer the difference from that currently authorized. The deferral will occur annually, with no carrying charge, with deferred costs being amortized over a three-year period, beginning in the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases will be the actual operation and maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. For 2011, we deferred $0.1 million of maintenance costs in Idaho.

Oregon General Rate Cases

In September 2009, we entered into an all-party settlement stipulation in our general rate case that was filed with the OPUC in June 2009. This settlement stipulation was approved by the OPUC in October 2009. The new natural gas rates became effective on November 1, 2009. As agreed to in the settlement, base natural gas rates for our Oregon customers increased by an average of 7.1 percent, which was designed to increase annual revenues by $8.8 million.

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.

Proposed Electric Decoupling — Washington

In the September 2011 Washington general rate case settlement (which was approved by the WUTC in December 2011), one party, the Northwest Energy Coalition (NWEC), did not sign the agreement and is pursuing an electric decoupling mechanism in Washington. The issue of electric decoupling is being addressed through a separate procedural schedule. Decoupling separates the link between actual kWh sales and the recovery of our fixed costs. In summary, the NWEC proposes that actual fixed cost recovery per customer be compared to authorized fixed cost recovery per customer, and any difference be deferred for later surcharge or rebate to customers. The WUTC has established a procedural schedule that would provide for a decision in the second quarter of 2012.

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. Effective November 1, 2009, natural gas rates decreased 22 percent in Oregon, 26 percent in Washington and 23 percent in Idaho. In Oregon, we absorb (gain or loss) 10 percent of the difference between actual and projected gas costs for supply that is not hedged. Total net deferred natural gas costs were a liability of $12.1 million as of December 31, 2011, a decrease from $22.1 million as of December 31, 2010. In February 2012, we filed PGA requests with the respective utility commissions to decrease natural gas rates 6.4 percent in Washington and 6.0 percent in Idaho effective March 1, 2012. 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.

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 $12.9 million as of December 31, 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.

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

The following is a summary of the ERM:

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

Under the ERM, we make an annual filing on or before April 1 of each year to provide the opportunity for the WUTC staff and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. 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 liability of $0.7 million as of December 31, 2011 compared to a regulatory asset of $18.3 million as of December 31, 2010.

Natural Gas Safety Regulations

On February 3, 2012, President Obama signed into law the "Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011" mandating new regulations be created to address public safety concerns. Regulations include requiring automatic shut-off valves on pipeline mains, increased installation of excess flow valves on gas service piping, increased "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 are included in the Act. We are evaluating the Act and cannot predict the impact the Act may ultimately have on our operations.

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 on our natural gas system.

RESULTS OF OPERATIONS

The following provides an overview of changes in our 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.

2011 compared to 2010

Utility revenues increased $23.7 million, after elimination of intracompany revenues of $93.1 million in 2011 and $65.9 million in 2010. Including intracompany revenues, electric revenues increased $13.9 million and natural gas revenues increased $37.0 million. Retail electric revenues increased $51.1 million due to general rate increases and an increase in volumes sold caused by colder weather during the first three months of 2011 compared to 2010. In addition, sales of fuel increased $47.1 million (reflecting lower usage of our thermal generating plants and sales of natural gas fuel not used in generation). These increases in retail electric revenues and sales of fuel were partially offset by a decrease in wholesale electric revenues of $87.2 million (due to a decrease in wholesale prices and volumes). Retail natural gas revenues increased $40.3 million due to an increase in volumes caused by colder weather and prices from rate increases, while wholesale natural gas revenues decreased $1.5 million.

Non-utility revenues increased $37.4 million to $178.3 million primarily as a result of Ecova's revenues increasing $35.8 million primarily due to 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 $1.6 million (excluding intercompany revenues) primarily due to increased sales at METALfx.

Utility resource costs decreased $5.0 million, after elimination of intracompany resource costs of $93.1 million in 2011 and $65.9 million in 2010. Including intracompany resource costs, electric resource costs increased $5.1 million and natural gas resource costs increased $17.1 million. The increase in electric resource costs was primarily due to an increase in other fuel costs (represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation as part of the resource optimization process) and the amortization of deferred power supply costs, partially offset by 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 $12.8 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 $5.1 million driven by additions to utility plant.

Utility taxes other than income taxes increased $10.0 million primarily reflecting higher retail revenue related taxes, as well as increased property taxes.

Non-utility other operating expenses increased $31.9 million primarily due to an increase of $29.6 million for Ecova reflecting increased costs necessary for business growth and the acquisition of Loyalton.

Interest expense decreased $1.9 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.

Capitalized interest increased $2.6 million due to higher average construction work in progress balances and higher borrowing rates (including an increase on short-term borrowing rates used in the calculation).

Other expense — net decreased $3.8 million primarily due to a decrease in donations, a decrease in losses on investments (including a $2.2 million impairment of our investment in a fuel cell business recorded in 2010), partially offset by a decrease in equity-related AFUDC.

Income taxes increased $5.5 million and our effective tax rate was 35.4 percent for 2011 compared to 35.0 percent for 2010. This increase in expense was primarily due to an increase in income before income taxes. 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 2010.

2010 compared to 2009

Utility revenues increased $22.6 million due to increased electric revenues of $133.5 million, partially offset by decreased natural gas revenues of $43.2 million and intracompany revenues of $65.9 million. Wholesale electric revenues increased $77.1 million (primarily due to an increase in volumes sold and partially due to an increase in wholesale prices) and sales of fuel increased $73.4 million (reflecting increased thermal generation resource optimization). These increases in electric revenues were partially offset by a decrease in retail electric revenues of $20.6 million, due to a decrease in volumes sold and prices resulting from the elimination of the ERM surcharge in February 2010, offset by general rate increases. Retail natural gas revenues decreased $98.3 million (due to decreased retail rates and decreased volumes), while wholesale natural gas revenues increased $53.8 million (due to increased volumes and wholesale prices).

Non-utility revenues increased $23.5 million to $140.9 million primarily as a result of Ecova's revenues increasing $24.7 million primarily due to the acquisition of Ecos in the third quarter of 2009, as well as moderate growth in expense management and energy management services.

Utility resource costs decreased $4.5 million as natural gas resource costs decreased $38.8 million and intracompany resource costs decreased $65.9 million, while electric resource costs increased $100.2 million. The decrease in natural gas resource costs primarily reflects the purchased gas cost adjustments implemented in the fourth quarter of 2009. The increase in electric resource costs was primarily due to an increase in fuel costs (due to an increase in thermal generation) and other fuel costs (represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation as part of the resource optimization process).

Utility other operating expenses increased $12.6 million primarily due to increased outside services (primarily consulting costs) of $5.1 million, compensation costs of $3.6 million, as well as injuries and damages of $1.9 million.

Utility depreciation and amortization increased $6.8 million driven by additions to utility plant.

Utility taxes other than income taxes decreased $3.2 million primarily reflecting lower retail revenue related taxes, partially offset by increased property taxes.

Other non-utility operating expenses increased $3.8 million reflecting an increase of $19.1 million for Ecova due to the acquisition of Ecos in the third quarter of 2009, as well as moderate growth in expense management and energy management services. The increase was partially offset by decreased operating expenses from the other businesses primarily due to the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations for this agreement were conveyed to Shell Energy through the end of 2009. These rights and obligations were conveyed to Avista Utilities' operations in January 2010.

Interest expense increased $10.7 million primarily due to the consolidation of Spokane Energy (increased interest expense $5.5 million) and the issuance of $250.0 million of long-term debt in September 2009. During 2009, we carried relatively high balances on our committed line of credit at relatively low interest rates. This was replaced with long-term debt at a higher interest rate.

Interest expense to affiliated trusts decreased $1.3 million because of the redemption of $61.9 million of long-term debt to affiliated trusts in April 2009 and a decrease in the variable interest rate on the remaining debt outstanding.

Other expense — net increased $8.8 million primarily due to an increase in donations, a decrease in interest income (primarily interest on regulatory deferrals due to lower balances) and a $2.2 million impairment of our investment in a fuel cell business.

Income taxes increased $4.8 million and our effective tax rate was 35.0 percent for 2010 compared to 34.3 percent for 2009. This increase was due in part to an increase in income before income taxes. 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 2010 (recorded in the third quarter). In 2009, we recorded adjustments related to Internal Revenue Service (IRS) audits and adjustments for the 2008 filed federal tax return that had a favorable impact to income tax expense of $3.2 million (Avista Utilities) for 2009 (recorded in the third quarter).

AVISTA UTILITIES

2011 compared to 2010

Net income for Avista Utilities was $90.9 million for 2011, an increase from $86.7 million for 2010. Avista Utilities' income from operations was $209.0 million for 2011 compared to $208.1 million for 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 increase in net income from Avista Utilities was also due to a decrease in interest expense (net of capitalized interest) and a decrease in donations (included in other expenses).

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

	Electric		Natural Gas		Intracompany		Total	
	2011	2010	2011	2010	2011	2010	2011	2010
Operating revenues	$ 988,187	$ 974,283	$ 548,225	$ 511,249	$ (93,090)	$ (65,886)	$ 1,443,322	$ 1,419,646
Resource costs	484,359	479,252	398,779	381,709	(93,090)	(65,886)	790,048	795,075
Gross margin	$ 503,828	$ 495,031	$ 149,446	$ 129,540	$ —	$ —	$ 653,274	$ 624,571

Avista Utilities' operating revenues increased $23.7 million and resource costs decreased $5.0 million, which resulted in an increase of $28.7 million in gross margin. The gross margin on electric sales increased $8.8 million and the gross margin on natural gas sales increased $19.9 million. The increase in electric gross margin was due to colder weather during the first quarter of 2011 that increased retail loads and general rate increases. For 2011, we recognized a benefit of $6.4 million under the ERM in Washington. As part of a rate case settlement there were no deferrals under the ERM in 2010. For 2010, power supply costs were $7.1 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 (particularly in the first quarter) and partially due to general rate increases.

Intracompany revenues and resource costs represent purchases and sales of natural gas between our natural gas distribution operations and our electric generation operations (as fuel for our generation plants). These transactions are eliminated in the presentation of 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 year ended December 31 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2011	2010	2011	2010
Residential	$ 324,835	$ 296,627	3,728	3,618
Commercial	280,139	265,219	3,122	3,100
Industrial	122,560	114,792	2,147	2,099
Public street and highway lighting	6,941	6,702	26	26
Total retail	734,475	683,340	9,023	8,843
Wholesale	78,305	165,553	2,796	3,803
Sales of fuel	153,470	106,375	—	—
Other	21,937	19,015	—	—
Total	$ 988,187	$ 974,283	11,819	12,646

Retail electric revenues increased $51.1 million due to an increase in total MWhs sold (increased revenues $14.6 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 $36.5 million). Compared to 2010, residential electric use per customer increased 3 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 $87.2 million due to a decrease in sales prices (decreased revenues $59.0 million) and a decrease in sales volumes (decreased revenues $28.2 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 first quarter.

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market rather than operate the generating units. The revenues from sales of fuel increased $47.1 million due to an increase in sales of natural gas fuel as part of thermal generation resource optimization activities and lower usage of our thermal generation plants in 2011 as compared to 2010. This was due in part to increased hydroelectric generation. In 2011, $38.6 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. In 2010, $24.7 million of these sales were made to our natural gas operations.

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

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

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2011	2010	2011	2010
Residential	$ 219,557	$ 193,169	207,202	188,546
Commercial	111,964	98,257	125,344	113,422
Interruptible	2,519	2,738	4,503	4,443
Industrial	4,180	3,756	5,654	5,312
Total retail	338,220	297,920	342,703	311,723
Wholesale	195,882	197,364	510,755	468,887
Transportation	6,709	6,470	152,515	142,093
Other	7,414	9,495	440	393
Total	$ 548,225	$ 511,249	1,006,413	923,096

Retail natural gas revenues increased $40.3 million due to an increase in volumes (increased revenues $30.6 million) and higher retail rates (increased revenues $9.7 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 9 percent and commercial use per customer increased 10 percent. The increase in retail rates reflects purchased gas adjustments, as well as general rate increases.

Wholesale natural gas revenues decreased $1.5 million due to a decrease in prices (decreased revenues $17.5 million), partially offset by an increase in volumes (increased revenues $16.0 million). We plan for sufficient natural gas capacity to serve our retail customers on a theoretical peak day. As such, we generally have more pipeline and storage capacity than what is needed. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs. We hedge against expected natural gas volumes with forward purchases. In some situations, customer demand is below the amount hedged and we sell natural gas in excess of load requirements. In 2011, $54.5 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In 2010, $41.2 million of these sales were made to our electric generation operations. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.

The following table presents our average number of electric and natural gas retail customers for the year ended December 31:

	Electric Customers		Natural Gas Customers	
	2011	2010	2011	2010
Residential	316,762	315,283	284,504	282,721
Commercial	39,618	39,489	33,540	33,431
Interruptible	—	—	38	38
Industrial	1,380	1,376	255	254
Public street and highway lighting	455	449	—	—
Total retail customers	358,215	356,597	318,337	316,444

The following table presents our utility resource costs for the year ended December 31 (dollars in thousands):

	2011	2010
Electric resource costs:		
Power purchased	$ 169,845	$ 186,312
Power cost amortizations, net	31,910	2,798
Fuel for generation	84,367	142,154
Other fuel costs	164,173	114,211
Other regulatory amortizations, net	16,381	17,772
Other electric resource costs	17,683	16,005
Total electric resource costs	484,359	479,252
Natural gas resource costs:		
Natural gas purchased	396,497	386,828
Natural gas cost amortizations, net	(10,041)	(18,741)
Other regulatory amortizations, net	12,323	13,622
Total natural gas resource costs	398,779	381,709
Intracompany resource costs	(93,090)	(65,886)
Total resource costs	$ 790,048	$ 795,075

Power purchased decreased $16.5 million due to a decrease in the volume of power purchases (decreased costs $18.0 million), partially offset by a slight increase in wholesale prices (increased costs $1.5 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 $31.9 million for 2011 compared to $2.8 million for 2010. During 2011, we recovered (collected as revenue) $14.9 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 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 $4.2 million in Idaho and $12.8 million in Washington for potential future rebate to customers.

Fuel for generation decreased $57.8 million primarily due to a decrease in thermal generation. This was due in part to an increase in hydroelectric generation.

Other fuel costs increased $50.0 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 $9.7 million due to an increase in total therms purchased (increased costs $31.0 million), partially offset by a decrease in the price of natural gas (decreased costs $21.3 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 and resource optimization process. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs. During 2011, natural gas resource costs were reduced by $10.0 million reflecting the rebate of a deferred liability for natural gas costs through the purchased gas adjustments.

2010 compared to 2009

Net income for Avista Utilities was $86.7 million for 2010 and 2009. Avista Utilities' income from operations was $208.1 million for 2010 compared to $195.4 million for 2009. The increase in income from operations was primarily due to an increase in gross margin (operating revenues less resource costs) and a decrease in taxes other than income taxes, partially offset by an increase in other operating expenses and depreciation and amortization.

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

	Electric		Natural Gas		Intracompany		Total	
	2010	2009	2010	2009	2010	2009	2010	2009
Operating revenues	$ 974,283	$ 840,783	$ 511,249	$ 554,418	$ (65,886)	$ —	$ 1,419,646	$ 1,395,201
Resource costs	479,252	379,058	381,709	420,481	(65,886)	—	795,075	799,539
Gross margin	$ 495,031	$ 461,725	$ 129,540	$ 133,937	$ —	$ —	$ 624,571	$ 595,662

Avista Utilities' operating revenues increased $24.4 million and resource costs decreased $4.5 million, which resulted in an increase of $28.9 million in gross margin. The gross margin on electric sales increased $33.3 million and the gross margin on natural gas sales decreased $4.4 million. The increase in electric gross margin was due to general rate increases and power supply costs below the amount included in base retail rates in Washington, partially offset by warmer weather (during the heating season) that reduced retail loads. The decrease in our natural gas gross margin was primarily due to warmer weather that reduced retail loads, partially offset by general rate increases.

Intracompany revenues and resource costs represent purchases and sales of natural gas between our natural gas distribution operations and our electric generation operations (as fuel for our generation plants). 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.

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

	Electric Operating Revenues		Electric Energy MWh sales	
	2010	2009	2010	2009
Residential	$ 296,627	$ 315,649	3,618	3,791
Commercial	265,219	273,954	3,100	3,177
Industrial	114,792	107,741	2,099	1,948
Public street and highway lighting	6,702	6,607	26	26
Total retail	683,340	703,951	8,843	8,942
Wholesale	165,553	88,414	3,803	2,354
Sales of fuel	106,375	32,992	—	—
Other	19,015	15,426	—	—
Total	$ 974,283	$ 840,783	12,646	11,296

Retail electric revenues decreased $20.6 million due to a decrease in total MWhs sold (decreased revenues $7.5 million) primarily due to a decrease in use per customer as a result of warmer weather in the heating season, and a decrease in revenue per MWh (decreased revenues $13.1 million). Compared to 2009, residential electric use per customer was down 5 percent and commercial use per customer decreased 3 percent. The decrease in revenue per MWh was primarily due to the elimination of the ERM surcharge in February 2010, partially offset by the Washington and Idaho general rate increases. The decrease in revenue per MWh was also due to a greater percentage of revenue derived from industrial customers.

Wholesale electric revenues increased $77.1 million due to an increase in sales prices (increased revenues $14.0 million) and an increase in sales volumes (increased revenues $63.1 million). The increase in sales volumes primarily related to increased resource optimization activities and lower than expected retail sales.

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market rather than operate the generating units. Sales of fuel increased $73.4 million due to an increase in thermal generation resource optimization activities in 2010 as compared to 2009. In 2010, $24.7 million of these sales were made to our natural gas operations and are reflected 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 (no deferrals for 2010) and the PCA mechanism.

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

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2010	2009	2010	2009
Residential	$ 193,169	$ 251,022	188,546	207,979
Commercial	98,257	135,236	113,422	126,345
Interruptible	2,738	4,709	4,443	5,360
Industrial	3,756	5,236	5,312	5,558
Total retail	297,920	396,203	311,723	345,242
Wholesale	197,364	143,524	468,887	397,977
Transportation	6,470	6,067	142,093	144,580
Other	9,495	8,624	393	502
Total	$ 511,249	$ 554,418	923,096	888,301

Retail natural gas revenues decreased $98.3 million due to lower retail rates (decreased revenues $66.2 million) and volumes (decreased revenues $32.0 million). We sold less retail natural gas in 2010 as compared to 2009 primarily due to warmer weather. Compared to 2009, residential natural gas use per customer was down 10 percent and commercial use per customer decreased 11 percent. The decrease in retail rates reflects purchased gas adjustments, partially offset by general rate increases.

Wholesale natural gas revenues increased $53.8 million due to an increase in prices (increased revenues $24.0 million) and volumes (increased revenues $29.8 million). We plan for sufficient natural gas capacity to serve our retail customers on a theoretical peak day. As such, we generally have more pipeline and storage capacity than what is needed. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs. With lower retail loads in 2010 as compared to 2009, we had more opportunity to optimize transportation resources. We hedge against expected natural gas volumes with forward purchases. In some situations, customer demand is below the amount hedged and we sell natural gas in excess of load requirements. Part of the increase in the volume of wholesale natural gas sales reflects lower than expected retail loads in 2010 and the sale of excess natural gas purchased. In 2010, $41.2 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 year ended December 31:

	Electric Customers		Natural Gas Customers	
	2010	2009	2010	2009
Residential	315,283	313,884	282,721	280,667
Commercial	39,489	39,276	33,431	33,214
Interruptible	—	—	38	42
Industrial	1,376	1,394	254	258
Public street and highway lighting	449	444	—	—
Total retail customers	356,597	354,998	316,444	314,181

The following table presents our utility resource costs for the year ended December 31 (dollars in thousands):

	2010	2009
Electric resource costs:		
Power purchased	$ 186,312	$ 193,683
Power cost amortizations, net	2,798	31,102
Fuel for generation	142,154	89,602
Other fuel costs	114,211	31,881
Other regulatory amortizations, net	17,772	19,602
Other electric resource costs	16,005	13,188
Total electric resource costs	479,252	379,058
Natural gas resource costs:		
Natural gas purchased	386,828	389,034
Natural gas cost amortizations, net	(18,741)	20,256
Other regulatory amortizations, net	13,622	11,191
Total natural gas resource costs	381,709	420,481
Intracompany resource costs	(65,886)	—
Total resource costs	$ 795,075	$ 799,539

Power purchased decreased $7.4 million due to a decrease in wholesale prices (decreased costs $38.9 million), partially offset by an increase in the volume of power purchases (increased costs $31.5 million). The increase in volumes was primarily due to purchasing power to cover for below normal hydroelectric generation, the purchased power agreement for the Lancaster Plant and an increase in wholesale sales volumes related to optimization.

Net amortization of deferred power costs was $2.8 million for 2010 compared to $31.1 million for 2009. During 2010, we recovered (collected as revenue) $6.8 million of previously deferred power costs in Washington and $13.0 million in Idaho. The Washington ERM surcharge was eliminated in February 2010, since the previous balance of deferred power costs had been recovered. During 2010, we deferred $9.8 million of power costs in Idaho, as power supply costs exceeded the amount included in base retail rates. In Washington, we deferred $6.8 million of costs (included in other regulatory assets) associated with the Lancaster Project. This was the maximum deferral for 2010 as agreed to in the Washington general rate case settlement. In that settlement, the parties agreed that there would not be any deferrals under the ERM for 2010. The net effect of the settlement for the Lancaster Plant deferrals and the ERM was slightly positive to 2010 earnings.

Fuel for generation increased $52.6 million primarily due to an increase in thermal generation, including fuel for the Lancaster Plant. In 2009, we experienced an outage at Colstrip, which reduced thermal generation.

Other fuel costs increased $82.3 million. This represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation, as part of the resource optimization process. The associated revenues are reflected as sales of fuel.

The expense for natural gas purchased decreased $2.2 million due to a decrease in the price of natural gas (decreased costs $20.7 million), partially offset by an increase in the total therms purchased (increased costs $18.5 million). Total therms purchased increased due to wholesale sales with the balancing of loads and resources as part of the natural gas procurement and optimization process, partially offset by decreased retail sales volumes. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs. During 2010, natural gas resource costs were reduced by $18.7 million reflecting the rebate of a deferred liability for natural gas costs through the purchased gas adjustments implemented in November 2009.

ECOVA

2011 compared to 2010

Ecova's net income attributable to Avista Corp. was $9.7 million for 2011 compared to $7.4 million for 2010. Operating revenues increased $35.8 million and total operating expenses increased $30.8 million. The increase in operating revenues was primarily due growth in energy management and expense management services, as well as the acquisition of Loyalton effective December 31, 2010, which added $8.5 million to 2011 operating revenues. Ecova's organic revenue growth was approximately 13 percent from 2010 to 2011. The increase in operating expenses primarily reflects increased costs necessary for business growth and the acquisition of Loyalton. During the fourth quarter of 2011, Ecova determined that certain revenues, which had previously been reported net of expenses, should be reported on a gross basis. This increased operating revenues and expenses by $9.2 million with no impact to net income for 2011. As of December 31, 2011, Ecova had 645 expense management customers representing 497,000 billed sites in North America. In 2011, Ecova managed bills totaling $18.3 billion, an increase of $1.0 billion as compared to 2010.

2010 compared to 2009

Ecova's net income attributable to Avista Corporation was $7.4 million for 2010 compared to $5.3 million for 2009. Operating revenues increased $24.8 million and operating expenses increased $20.5 million. The increase in net income attributable to Avista Corporation, operating revenues and expenses was primarily due to the third quarter 2009 acquisition of Ecos, as well as moderate growth in expense management and energy management services. The increase in operating expenses was also due to the amortization of intangible assets from the acquisition of Ecos. As of December 31, 2010, Ecova had 534 expense management customers representing 361,000 billed sites in North America. The decrease in billed sites at year-end 2010 as compared to year-end 2009 billed sites of 421,000 was due to the loss of a customer that had a significant number of billed sites, but represented only approximately 1 percent of annual revenues. In 2010, Ecova managed bills totaling $17.3 billion, a decrease of $0.1 billion as compared to 2009. This decrease was primarily due to a decrease in the average value of each bill processed.

OTHER BUSINESSES

2011 compared to 2010

The net loss from these operations was $0.3 million for 2011 compared to $1.7 million for 2010. Operating revenues decreased $20.7 million and total operating expenses decreased $20.2 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 $1.4 million for 2011 compared to $0.8 million for 2010. Losses on investments were $0.5 million for 2011 compared to losses of $3.3 million for 2010. The loss for 2010 included a $2.2 million impairment of our investment in a fuel cell business.

2010 compared to 2009

The net loss attributable to Avista Corporation from these operations was $1.7 million for 2010 compared to $5.0 million for 2009. Operating revenues increased $21.0 million, operating expenses increased $8.4 million, and interest expense increased $5.3 million. The increase in operating revenues, operating expenses and interest expense was primarily due to the consolidation of Spokane Energy effective January 1, 2010, which had no impact on the net loss attributable to Avista Corporation. The improvement in results for these businesses in 2010 was due in part to increased earnings at METALfx, which had net income of $0.8 million for 2010, compared to $0.2 million for 2009. We also had decreased litigation costs related to the remaining contracts and previous operations of Avista Energy. Losses on long-term investments were $3.3 million for 2010 compared to $0.8 million for 2009. In 2009, we recorded an impairment of a commercial building of $3.0 million.

ACCOUNTING STANDARDS TO BE ADOPTED IN 2012

At this time, we are not expecting the adoption of accounting standards to have a material impact on our financial condition, results of operations and cash flows in 2012. For information on accounting standards adopted in 2011 and earlier periods, refer to "Note 2 of the Notes to Consolidated Financial Statements."

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. The following accounting policies represent those that our management believes are particularly important to the consolidated financial statements that require the use of estimates and assumptions:

Avista Utilities Operating Revenues

Operating revenues for our utility business related to the sale of energy are generally recorded when service is rendered or energy is delivered to our customers. The determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, we estimate the amount of energy delivered to customers since the date of the last meter reading and the corresponding unbilled revenue is estimated and recorded. Our estimate of unbilled revenue is based on:

- the number of customers,
- current rates,
- meter reading dates,
- actual native load for electricity, and
- actual throughput for natural gas.

Any difference between actual and estimated revenue is automatically corrected in the following month when the actual meter reading and customer billing occurs.

Regulatory Accounting

We prepare our consolidated financial statements in accordance with regulatory accounting practices. This requires that certain costs and/or obligations (such as incurred power and natural gas costs not currently recovered through rates, but expected to be recovered in the future) be reflected as deferred charges on our Consolidated Balance Sheets and are not reflected in our Consolidated Statements of Income until the period during which matching revenues are recognized. We expect to recover our regulatory assets through future rates. Our regulatory assets are subject to review for prudence and recoverability. As such, certain deferred costs may be disallowed by our regulators. If at some point in the future we determine that we no longer meet the criteria for continued application of regulatory accounting for all or a portion of our regulated operations, we could be:

- required to write off regulatory assets, and
- precluded from the future deferral of costs not recovered through rates when such costs are incurred, even if we expect to recover such costs in the future.

Utility Energy Commodity Derivative Assets and Liabilities

Our utility 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 our management of loads and resources and certain contracts are considered derivative instruments. The WUTC and the IPUC issued accounting orders authorizing us 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 us to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Consolidated Statements of Income. Realized gains or losses are recognized in the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases. We use quoted market prices and forward price curves to estimate the fair value of our utility derivative commodity instruments. As such, the fair value of utility derivative commodity instruments recorded on our Consolidated Balance Sheets is sensitive to market price fluctuations that can occur on a daily basis.

Pension Plans and Other Postretirement Benefit Plans

We have a defined benefit pension plan covering substantially all regular full-time employees at Avista Utilities.

Our Finance Committee of the Board of Directors:

- establishes investment policies, objectives and strategies that seek an appropriate return for the pension plan, and
- reviews and approves changes to the investment and funding policies.

We have contracted with an investment consultant who is responsible for managing/monitoring the individual investment managers. The investment managers' performance and related individual fund performance is reviewed at least quarterly by an internal benefits committee and by the Finance Committee to monitor compliance with our established investment policy objectives and strategies.

Our pension plan assets are invested primarily in marketable debt and equity securities. Pension plan assets may also be invested in real estate, absolute return, venture capital/private equity and commodity funds. In seeking to obtain the desired return to fund the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee. The Finance Committee has established investment allocation percentages by asset classes as disclosed in "Note 10 of the Notes to Consolidated Financial Statements."

We also have a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to our 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.

Pension costs (including the SERP) were $23.9 million in 2011, $21.3 million for 2010 and $25.8 million for 2009. Of our pension costs, approximately 65 percent are expensed and 35 percent are capitalized consistent with labor charges. The costs related to the SERP are expensed. Our costs for the pension plan are determined in part by actuarial formulas that are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension costs are affected by:

- employee demographics (including age, compensation and length of service by employees),
- the amount of cash contributions we make to the pension plan, and
- the return on pension plan assets.

Changes made to the provisions of our pension plan may also affect current and future pension costs. Pension plan costs may also be significantly affected by changes in key actuarial assumptions, including the:

- expected return on pension plan assets,
- discount rate used in determining the projected benefit obligation and pension costs, and
- assumed rate of increase in employee compensation.

The change in pension plan obligations associated with these factors may not be immediately recognized as pension costs in our Consolidated Statement of Income, but we generally recognize the change in future years over the remaining average service period of pension plan participants. As such, our costs recorded in any period may not reflect the actual level of cash benefits provided to pension plan participants.

We have not made any changes to pension plan provisions in 2011, 2010 and 2009 that have had any significant effect on our recorded pension plan amounts. We have revised the key assumption of the discount rate in 2011, 2010 and 2009. Such changes had an effect on our pension costs in 2011, 2010 and 2009 and may affect future years, given the cost recognition approach described above. However, in determining pension obligation and cost amounts, our assumptions can change from period to period, and such changes could result in material changes to our future pension costs and funding requirements.

In selecting a discount rate, we consider yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits. In 2011, we decreased the pension plan discount rate to 5.05 percent from 5.70 percent in 2010. We used a discount rate of 6.30 percent in 2009. This increased the projected benefit obligation by approximately $40 million in 2011 and $31 million in 2010.

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by our plan. We used an expected long-term rate of return of 7.40 percent in 2011, 7.75 percent in 2010 and 8.5 percent in 2009. This increased pension costs by approximately $1.1 million in 2011 and by approximately $2.0 million in 2010. The actual return on plan assets, net of fees, was a gain of $14.7 million (or 4.7 percent) for 2011, a gain of $29.8 million (or 10.8 percent) for 2010 and a gain of $50.1 million (or 24.4 percent) for 2009. We periodically analyze the estimated long-term rate of return on assets based upon revisions to the investment portfolio.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage (dollars in thousands):

Actuarial Assumption	Change in Assumption	Effect on Projected Benefit Obligation	Effect on Pension Cost
Expected long-term return on plan assets	-0.5%	$ —*	$ 1,562
Expected long-term return on plan assets	+0.5%	—*	(1,562)
Discount rate	-0.5%	34,791	2,897
Discount rate	+0.5%	(31,072)	(2,616)

** Changes in the expected return on plan assets would not have an effect on our total pension liability.*

We provide certain health care and life insurance benefits for substantially all of our retired employees. We accrue the estimated cost of postretirement benefit obligations during the years that employees provide service. Assumed health care cost trend rates have a significant effect on the amounts reported for our postretirement plans. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase our accumulated postretirement benefit obligation as of December 31, 2011 by $14.8 million and the service and interest cost by $0.8 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease our accumulated postretirement benefit obligation as of December 31, 2011 by $12.3 million and the service and interest cost by $0.7 million.

Contingencies

We have unresolved regulatory, legal and tax issues for which there is inherent uncertainty for the ultimate outcome of the respective matter. We accrue a loss contingency if it is probable that an asset is impaired or a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. We also disclose losses that do not meet these conditions for accrual, if there is a reasonable possibility that a loss may be incurred.

For all material contingencies, we have made a judgment as to the probability of a loss occurring and as to whether or not the amount of the loss can be reasonably estimated. If the loss recognition criteria are met, liabilities are accrued or assets are reduced. However, no assurance can be given to the ultimate outcome of any particular contingency.

LIQUIDITY AND CAPITAL RESOURCES

REVIEW OF CASH FLOW STATEMENT

Overall — During 2011, positive cash flows from operating activities of $269.5 million were used to fund the majority of our cash requirements. These cash requirements included utility capital expenditures of $239.8 million and dividends of $63.7 million. In December 2011, we issued $85.0 million of long-term debt. The net proceeds from the issuance of debt were used to repay a portion of the borrowings outstanding under our $400.0 million committed line of credit. In total on a consolidated basis, we were able to reduce short-term borrowings by $14.0 million during 2011.

Operating Activities — Net cash provided by operating activities was $269.5 million for 2011 compared to $228.4 million for 2010. Net cash used in working capital components was $14.9 million for 2011, compared to $20.8 million for 2010. The net cash used during 2011 primarily reflects negative cash flows from other current assets (primarily related to an increase in deposits with counterparties), net cash outflows related to accounts payable and an increase in natural gas stored. These negative cash flows were partially offset by net cash inflows related to accounts receivable.

The net cash used during 2010 primarily reflects negative cash flows from accounts receivable (representing an increase in receivables outstanding at Avista Utilities and Ecova), and an increase in materials and supplies, fuel stock and natural gas stored. These negative cash flows were partially offset by net cash inflows related to accounts payable.

Net amortization of deferred power and natural gas costs was $21.9 million for 2011 compared to net deferrals of $9.8 million for 2010. The provision for deferred income taxes was $24.0 million for 2011 compared to $37.7 million for 2010. Contributions to our defined benefit pension plan were $26.0 million for 2011 compared to $21.0 million for 2010. Cash paid for interest decreased to $69.1 million for 2011, compared to $74.2 million for 2010.

Investing Activities — Net cash used in investing activities was $282.3 million for 2011, an increase compared to $253.2 million for 2010. Utility property capital expenditures increased by $37.6 million for 2011 as compared to 2010. At the end of 2011, the majority of Ecova's funds held for clients were held as securities available for sale (purchases of $96.6 million). In 2010, the funds held for clients were in money market funds. The net cash paid by subsidiaries for acquisitions in 2011 of $31.4 million primarily represents Ecova's acquisition of Prenova.

Financing Activities — Net cash provided by financing activities was $18.1 million for 2011 compared to net cash provided of $57.2 million for 2010. During 2011, short-term borrowings on Avista Corp.'s committed line of credit decreased $49.0 million. Borrowings on Ecova's committed line of credit increased $35.0 million and these proceeds were used to fund the acquisition of Prenova. Cash dividends paid increased to $63.7 million (or $1.10 per share) for 2011 from $55.7 million (or $1.00 per share) for 2010. We issued $26.5 million of common stock during 2011, including $19.5 million under a sales agency agreement. We cash settled interest rate swap agreements for $10.6 million related to the pricing of $85.0 million of long-term debt issued in December 2011. Customer fund obligations at Ecova increased $17.8 million.

During 2010, our short-term borrowings increased $23.0 million due to a net increase in the amount of debt outstanding under our committed line of credit. In December 2010, we issued $137.0 million (net proceeds of $136.4 million) of long-term debt. A portion of the proceeds were used to redeem $75.0 million of long-term debt scheduled to mature in 2013. In conjunction with the redemption of long-term debt, we paid a make-whole redemption premium of $10.7 million. We issued $46.2 million of common stock during 2010, including $43.2 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.

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

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 long-term capital markets in order to fund these needs as well as fund maturing debt. See further discussion at "Capital Resources."

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

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

- increases in demand (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 potentially higher energy commodity prices and increased other operating costs through our $400.0 million committed line of credit.

As of December 31, 2011, we had $310.0 million of available liquidity under our committed line of credit. With our $400.0 million credit facility that expires in February 2017, we believe that we have adequate liquidity to meet our needs for the next 12 months.

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

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. As of December 31, 2011, we had cash deposited as collateral of $18.2 million and letters of credit of $18.8 million outstanding related to our energy derivative contracts. 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 December 31, 2011, that we would potentially be required to post additional collateral of up to $147 million. The additional collateral amount is higher than the amount disclosed in "Note 6 of the Notes to 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 or letters of credit as collateral depending on fluctuations in the fair value of the instrument. This has not historically been significant to our liquidity position. As of December 31, 2011, we had interest rate swap agreements outstanding with a notional amount totaling $160 million and we had posted collateral of $4.2 million ($1.5 million in cash and $2.7 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 December 31, 2011, we would potentially be required to post additional collateral of up to $4.6 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.

Under the Dodd-Frank Act, "Swap Dealers" and "Major Swap Participants" generally will be required to collect minimum initial and variation margin from their counterparties for non-cleared swaps. However the requirement varies with the type of counterparty and the regulator of the "Major Swap Participant" or "Swap Dealer." Avista Corp. should be categorized as a counterparty that is a non-financial end user for the purposes of the Dodd-Frank Act, i.e., as a non-financial entity that engages in derivatives to hedge commercial risk. 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 certain swaps to be cleared and traded on exchanges or swap execution facilities. Such clearing requirements would result in a significant change from our current practice of bilaterally negotiated credit terms. An exemption to mandatory clearing is available under the Dodd-Frank Act for counterparties that are non-financial end users using swaps to hedge commercial risk. However, the cost of entering into a non-cleared swap that is available as a cleared swap may be greater and margin levels are expected to be higher.

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 December 31, 2011 and 2010 (dollars in thousands):

	December 31, 2011		December 31, 2010	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 7,474	0.3%	$ 358	— %
Current portion of nonrecourse long-term debt	13,668	0.5	12,463	0.5
Short-term borrowings	96,000	3.8	110,000	4.5
Long-term debt to affiliated trusts	51,547	2.0	51,547	2.1
Nonrecourse long-term debt	32,803	1.3	46,471	1.9
Long-term debt	1,169,826	45.7	1,101,499	45.0
Total debt	1,371,318	53.6	1,322,338	54.0
Total Avista Corporation stockholders' equity	1,185,701	46.4	1,125,784	46.0
Total	$ 2,557,019	100.0%	$ 2,448,122	100.0%

We need to finance capital expenditures and acquire additional funds for operations from time to time. The cash requirements needed to service our indebtedness, both short-term and long-term, reduces the amount of cash flow available to fund capital expenditures, purchased power, fuel and natural gas costs, dividends and other requirements. Our stockholders' equity increased $59.9 million during 2011 primarily due to net income and the issuance of common stock, partially offset by dividends.

We generally fund capital expenditures with a combination of internally generated cash and external financing. The level of cash generated internally and the amount that is available for capital expenditures fluctuates depending on a variety of factors. Cash provided by our utility operating activities, as well as issuances of long-term debt and common stock, are expected to be the primary source of funds for operating needs, dividends and capital expenditures for 2012. Borrowings under our $400.0 million committed line of credit will supplement these funds to the extent necessary.

We are planning to issue up to $45 million of common stock in 2012 in order to maintain our capital structure at an appropriate level for our business. In 2011, we issued $26.5 million of common stock, including $19.5 million under a sales agency agreement. As of December 31, 2011, we had 0.2 million shares available to be issued under this agreement and we expect to expand this agreement for a significant portion of our 2012 common stock issuances.

In December 2011, we issued $85.0 million of 4.45 percent First Mortgage Bonds due in 2041. The net proceeds from the sale of the bonds were used to repay a portion of the borrowings outstanding under our $400.0 million committed line of credit. We expect to issue up to $100.0 million of long-term debt in 2012.

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. In December 2011, this committed line of credit was amended to extend the expiration date to February 2017 and improve the pricing terms.

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 December 31, 2011, we were in compliance with this covenant with a ratio of 53.6 percent.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under our committed lines of credit were as follows as of and for the years ended December 31 (dollars in thousands):

	2011	2010	2009
Balance outstanding at end of year	$ 61,000	$ 110,000	$ 87,000
Letters of credit outstanding at end of year	$ 29,030	$ 27,126	$ 28,448
Maximum balance outstanding during the year	$ 130,000	$ 170,000	$ 275,000
Average balance outstanding during the year	$ 74,947	$ 80,230	$ 186,474
Average interest rate during the year	1.43%	0.60%	0.65%
Average interest rate at end of year	1.12%	0.57%	0.59%

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 December 31, 2011, Avista Corp. and its subsidiaries were in compliance with all of the covenants of their financing agreements.

As part of its cash management practices and operations, Ecova and Avista Corp. entered into a master promissory note in January 2012, where Ecova will from time to time make unsecured short-term loans to Avista Corp. The master promissory note limits the total outstanding indebtedness to no more than $50.0 million in principal. Additionally, such loans are required to be repaid on the last business day of each quarter (March, June, September and December) and sooner upon demand by Ecova. Amounts are loaned at a rate consistent with Avista Corp.'s credit facility.

We are restricted under our Restated Articles of Incorporation as to the additional preferred stock we can issue. As of December 31, 2011, we could issue $835.2 million of additional preferred stock at an assumed dividend rate of 8.5 percent. We are not planning to issue preferred stock.

Under the Mortgage and Deed of Trust securing our First Mortgage Bonds (including Secured Medium-Term Notes), we may issue additional First Mortgage Bonds in an aggregate principal amount equal to the sum of:

- 66⅔ percent of the cost or fair value (whichever is lower) of property additions which have not previously been made the basis of any application under the Mortgage, or
- an equal principal amount of retired First Mortgage Bonds which have not previously been made the basis of any application under the Mortgage, or
- deposit of cash.

However, we may not issue any additional First Mortgage Bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless our "net earnings" (as defined in the Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the First Mortgage Bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2011, our property additions and retired bonds would have allowed us to issue $727.1 million in aggregate principal amount of additional First Mortgage Bonds. We believe that we have adequate capacity to issue First Mortgage Bonds to meet our financing needs over the next several years.

AVISTA UTILITIES CAPITAL EXPENDITURES

Capital expenditures for our utility were $647.4 million for the years 2009 through 2011. We expect utility capital expenditures to be about $250 million for each of 2012, 2013 and 2014.

Our capital budget for 2012 includes the following (dollars in millions):

Transmission and distribution	$ 78
Information technology	44
Customer growth	37
Generation	31
Natural gas	23
Facilities	18
Environmental	9
Other	17
Total	$ 257

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 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. In December 2011, the amount of this committed line of credit was increased to $60.0 million, which is scheduled to decrease to $55.0 million on September 30, 2012 and $50.0 million on December 31, 2012. Ecova expects to expand this facility in 2012. The credit agreement is secured by substantially all of Ecova's assets. There were $35.0 million of borrowings outstanding under Ecova's credit agreement as of December 31, 2011. The proceeds from these borrowings were used to fund the acquisition of Prenova in November 2011. Ecova borrowed $25.0 million under this committed line of credit to fund a portion of the acquisition of LPB in January 2012.

ECOVA REDEEMABLE STOCK

In 2007, Ecova amended its employee stock incentive plan to provide an annual window at which time holders of common stock can put their shares back to Ecova providing the shares are held for a minimum of six months. Stock is reacquired at 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 $12.9 million as of December 31, 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 $38.9 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. These 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.

OFF-BALANCE SHEET ARRANGEMENTS

As of December 31, 2011, we had $29.0 million in letters of credit outstanding under our $400.0 million committed line of credit, an increase from $27.1 million as of December 31, 2010.

PENSION PLAN

As of December 31, 2011, our pension plan had assets with a fair value that was less than the benefit obligation under the plan. The pension plan funding deficit increased in 2011 primarily due to a decrease in the discount rate as well as market returns on assets that were lower than the expected long-term return on plan assets. We contributed $26 million to the pension plan in 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. 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).

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 6 of the Notes to Consolidated Financial Statements."

The following table summarizes our credit ratings as of February 28, 2012:

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

(1) Standard & Poor's lowest level of "investment grade" credit rating is BBB-.

(2) Moody's lowest level of "investment grade" credit rating is Baa3.

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

In February 2012, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.29 per share on the Company's common stock. This was an increase of $0.015 per share, or 5 percent from the previous quarterly dividend of $0.275 per share.

These contractual obligations do not include income tax payments.

CONTRACTUAL OBLIGATIONS

The following table provides a summary of our future contractual obligations as of December 31, 2011 (dollars in millions):

	2012	2013	2014	2015	2016	Thereafter
Avista Utilities:						
Long-term debt maturities	$ 7	$ 50	$ —	$ —	$ —	$ 1,127
Long-term debt to affiliated trusts	—	—	—	—	—	52
Interest payments on long-term debt (1)	65	64	63	63	63	648
Short-term borrowings	61	—	—	—	—	—
Energy purchase contracts (2)	353	260	227	189	166	1,677
Public Utility District contracts (2)	3	3	3	3	3	45
Operating lease obligations (3)	1	1	1	—	—	2
Other obligations (4)	29	30	31	28	33	247
Information services contracts	13	11	8	7	7	7
Pension plan funding (5)	44	44	44	44	—	—
Spokane Energy:						
Nonrecourse long-term debt maturities	14	15	16	1	—	—
Interest payments on nonrecourse long-term debt	3	2	1	—	—	—
Avista Capital (consolidated):						
Redeemable noncontrolling interests (6)	52	—	—	—	—	—
Short-term borrowings	35	—	—	—	—	—
Venture funds investments (7)	2	1	—	—	—	—
Operating lease obligations (3)	4	4	4	2	1	2
Total contractual obligations	$ 686	$ 485	$ 398	$ 337	$ 273	$ 3,807

(1) Represents our estimate of interest payments on long-term debt, which is calculated based on the assumption that all debt is outstanding until maturity. Interest on variable rate debt is calculated using the rate in effect at December 31, 2011.

(2) Energy purchase contracts were entered into as part of the obligation to serve our retail electric and natural gas customers' energy requirements. As a result, costs are generally recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost adjustment mechanisms.

(3) Includes the interest component of the lease obligation. Future capital lease obligations are not material.

(4) Represents operational agreements, settlements and other contractual obligations for our generation, transmission and distribution facilities. These costs are generally recovered through base retail rates.

(5) Represents our estimated cash contributions to the pension plan through 2015. We cannot reasonably estimate pension plan contributions beyond 2015 at this time.

(6) 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. These 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. In addition, certain shares acquired under Ecova's employee stock incentive plan are redeemable at the option of the shareholder.

(7) Represents a commitment to fund a limited partnership venture fund commitment made by a subsidiary of Avista Capital.

In addition to the contractual obligations disclosed above, we will incur additional operating costs and capital expenditures in future periods for which we are not contractually obligated as part of our normal business operations.

COMPETITION

Our utility electric and natural gas distribution business has historically been recognized as a natural monopoly. In each regulatory jurisdiction, our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are determined on a "cost of service" basis. Rates are designed to provide, after recovery of allowable operating expenses and capital investments, an opportunity for us to earn a reasonable return on investment as allowed by our regulators.

In retail markets, we compete with various rural electric cooperatives and public utility districts in and adjacent to our service territories in the provision of service to new electric customers. Alternate providers of energy may also compete with us for sales to existing customers. Similarly, our natural gas distribution operations compete with other energy sources including heating oil, propane and other fuels.

Certain natural gas customers could by-pass our natural gas system, reducing both revenues and recovery of fixed costs. To reduce the potential for such by-pass, we price natural gas services, including transportation contracts, competitively and have varying degrees of flexibility to price transportation and delivery rates by means of individual contracts. These individual contracts are subject to state regulatory review and approval. We have long-term transportation contracts with several of our largest industrial customers under which the customer assumes the risk of acquiring their own commodity while using our infrastructure for delivery. Such contracts reduce the risk of these customers by-passing our system in the foreseeable future and minimizes the impact on our earnings.

Also, non-utility businesses are developing new technologies and services to help energy consumers manage energy in new ways that may improve productivity and could alter demand for the energy we sell.

In wholesale markets, competition for available electric supply is influenced by the:

- localized and system-wide demand for energy,
- type, capacity, location and availability of generation resources, and
- variety and circumstances of market participants.

These wholesale markets are regulated by the FERC, which requires electric utilities to:

- transmit power and energy to or for wholesale purchasers and sellers,
- enlarge or construct additional transmission capacity for the purpose of providing these services, and
- transparently price and offer transmission services without favor to any party, including the merchant functions of the utility.

Participants in the wholesale energy markets include:

- other utilities,
- federal power marketing agencies,
- energy marketing and trading companies,
- independent power producers,
- financial institutions, and
- commodity brokers.

Ecova is subject to competition for service to existing customers and as they develop products and services and enter new markets. Competition from other companies may mean challenges for Ecova to be the first to market a new product or service to gain an advantage in market share. Other challenges for Ecova include the availability of funding and resources to meet capital needs, and rapidly advancing technologies which require continual product enhancement to avoid obsolescence.

ECONOMIC CONDITIONS AND UTILITY LOAD GROWTH

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

Economic growth in the region we serve has slowed significantly since it peaked five years ago, yet we continue to experience customer growth. We have three distinct metropolitan areas in our service area: Spokane, Washington, Coeur d'Alene, Idaho and Medford, Oregon; and we are tracking three separate economic indicators which impact our business: employment change, unemployment rates and foreclosure rates. We have observed mixed results during the economic downturn. The December 2011 employment indicators are negative except for Medford, unemployment rates are lower in all three areas and foreclosure rates have decreased compared to early periods. Compared to the U.S. the economy in our service area is broadly weaker than the national average. We expect the economy in our service area 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 early in 2011, but our southwestern Oregon service area has stabilized. Non-farm employment growth for 2011 was 0.1 percent in Medford, Oregon with large gains in hospitality, health services and retail trade offset by large declines in government. We observed employment declines of 1.3 percent in the Spokane area with losses in professional services and government, partially offset by gains in manufacturing. Employment declined by 2.1 percent in Coeur d'Alene, Idaho largely due to government job reductions. The U.S. nonfarm sector jobs grew by 1.3 percent in the same twelve-month period.

The unemployment rate went down in December 2011 from the year earlier level in Spokane, Medford, and Coeur d'Alene. The Spokane rate was 9.1 percent in December 2010 but declined to 9.0 percent in December 2011. Medford declined from 11.6 percent to 10.3 percent while Coeur d'Alene went from 10.8 percent to 9.8 percent. The U.S. rate declined from 9.1 percent to 8.3 percent in the same period.

The housing market in our service area has improved when measured by foreclosure rates, with two of our three metropolitan areas better than the national average. The December 2011 national rate was 0.16 percent with a higher than national average level at 0.19 percent in Jackson County, Oregon. The Spokane housing market was 0.06 percent and Kootenai County, Idaho was 0.09 percent and both were less than half the levels experienced a year ago.

Based on our forecast for electric customer growth to average 0.7 to 1.2 percent per year and natural gas customer growth to average 1.1 to 2.1 percent within our service area, we anticipate retail electric and natural gas load growth will average between 0.7 and 1.9 percent annually for the four-year period 2012–2015. We anticipate customer and load growth at the lower end of the range in 2012 and an economic recovery and modest recovery-trend growth as the economy strengthens during the four-year period. While the number of electric and natural gas customers is growing, the average annual usage by each residential customer has not changed significantly. Electric and natural gas sales growth have slowed as retail prices have increased relative to historical prices and Company sponsored conservation programs have intensified. Population increases and business growth in our three-state service territory remains above the national average. Natural gas loads for space heating vary significantly with annual fluctuations in weather within our service territories.

The forward-looking statements set forth above regarding retail load growth are based, in part, upon purchased economic forecasts and publicly available population and demographic studies. The expectations regarding retail load growth are also based upon various assumptions, including:

- assumptions relating to weather and economic and competitive conditions,
- internal analysis of company-specific data, such as energy consumption patterns,
- internal business plans, and
- an assumption that we will incur no material loss of retail customers due to self-generation or retail wheeling.

Changes in actual experience can vary significantly from our projections.

ENVIRONMENTAL ISSUES AND

OTHER CONTINGENCIES

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

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

Environmental laws and regulations may:

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

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

Climate Change and Greenhouse Gas Emission Reduction Initiatives

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

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

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

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

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

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

National Legislation

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

Recent EPA Initiatives Related to Climate Change

After a public comment and review period, in December 2009, the EPA issued an "endangerment finding" regarding GHG emissions from motor vehicles under section 202(a) of Clean Air Act (CAA). Specifically, the EPA found that the combined emissions of GHG from new motor vehicles and new motor vehicle engines contribute to the GHG pollution which threatens public health and welfare. 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.

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

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.

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 GHG emissions associated with the importation of power to serve our Washington loads. The state of Washington has yet to identify how it might impose or enforce GHG emission reductions. Nevertheless, the State will make significant progress in meeting its GHG emission targets in light of the enactment of SB 5769, which codifies an agreement that the only coal-fired generation facility operating in the state (with which we have no involvement) to completely cease coal-fired operations by 2025.

Washington State's Department of Ecology has adopted regulations to ensure that its State Implementation Plan comports with the requirements of the EPA's regulation of GHG emissions. We will continue to monitor actions by the department as it may proceed to adopt additional regulations under its CAA authorities. Late in 2011, a Federal District Court ruled that the Department of Ecology must require six refineries located in the State to install reasonably available control technology to control and reduce their greenhouse gas emissions. This decision turned, in part, on the meaning of "air contaminate" under Washington law. The court observed that while the operative statute did not explicitly identify greenhouse gases, Governor Gregoire's Executive Order (09-05) defined "air contaminate" as including greenhouse gases. It remains to be determined whether the decision will be appealed or if and how it might impact other industries.

Washington and Oregon apply a GHG emissions performance standard to electric generation facilities used to serve loads in their jurisdictions. 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 qualified 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 could result in penalties of $50 per MWh or greater being assessed against a utility for each MWh it is deficient in meeting a standard. A utility would be deemed to comply with the renewable energy standard if it invests at least 4 percent of its total annual retail revenue requirement on the incremental costs of renewable energy resources and/or renewable energy credits. As noted in the following section, we have taken the steps necessary to meet the requirements of I-937.

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 105 MW Palouse Wind, LLC project, which is expected to help meet the requirements of Washington state Energy Independence Act (I-937) beginning in 2016, as well as provide a new resource to serve our customers' increasing energy needs.
- An additional 42 aMW of wind or qualifying renewable resource or energy credits are required under the same Act beginning in 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 into a 30-year power purchase agreement (PPA) with Palouse Wind, LLC (Palouse Wind), an affiliate of First Wind Holdings, LLC. Under the PPA, we will acquire all of the power and renewable attributes produced by a wind project being developed by Palouse Wind in Whitman County, Washington. The wind project is expected to have a nameplate capacity of approximately 105 MW and produce approximately 40 aMW with deliveries beginning by the end of 2012. We decided to enter into this PPA due, in part, to market changes reducing the cost of renewable resource projects. This was due, in part, to tax incentives for the construction of renewable resource projects that remain in effect through 2012. We acquired the development rights for a separate wind generation site near Reardan, Washington in 2008 and continue to study that site in preparation for later development. We plan to meet the state of Washington's renewable energy standards until 2016 with a combination of qualified upgrades at our existing hydroelectric generation plants. The power purchased from Palouse Wind will help to meet our Washington renewable energy requirements beginning in 2016, as well as provide a new energy resource to serve our system retail load requirements. Under the PPA, we have the option to purchase the wind project each year following the 10th anniversary of the commercial operation date at a price determined under the contract.

The amount of renewable resources in our future IRPs could change if the cost effectiveness of those resources changes or if 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 Fahrenheit 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), Coyote Springs 2 (which will expire in 2013), the Kettle Falls GS (which will be renewed in 2012), and the Rathdrum CT (which will expire in 2016). Boulder Park and the Northeast CT currently require only minor source operating permits based on their limited operation and emissions. The CAA also requires Acid Rain Program monitoring, reporting and emissions trading for Colstrip, Coyote Springs 2 and the Rathdrum CT. We continue to monitor legislative and regulatory developments for several programs within the CAA such as the National Ambient Air Quality Standards (NAAQS), New Source Performance Standards and the National Emission Standards for Hazardous Air Pollutants (NESHAPs) or Maximum Achievable Control Technology (MACT).

Montana Mercury Regulation and the EPA's Mercury Air Toxic Standards (MATS)

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

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

National Ambient Air Quality Standards (NAAQS)

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

Regional Haze Program

The United States Congress addressed regional visibility in the 1990 CAA amendments and the EPA published the final Regional Haze regulations in 2005. The EPA's regulations set a national goal of eliminating man-made visibility degradation in Class I areas by the year 2064. The States were expected to take actions through State Implementation Plans (SIPs) to make "reasonable progress" through 10-year plans, including application of Best Available Retrofit

Technology (BART) requirements. In 2009, the EPA announced that many states had failed to submit the required SIPs by the 2007 deadline. In 2011, environmental groups sued the EPA for inaction which resulted in court ordered deadlines for a Montana Federal Implementation Plan (FIP) in July 2012.

BART is a retrofit program applied to large emission sources, including electric generating units built between 1962 and 1977. In February 2007, Colstrip was notified by the EPA that Colstrip Units 1 & 2 (of which we are not an owner) were determined to be subject to the EPA's BART requirements. In November 2010, the EPA issued a request for additional reasonable progress information for Colstrip Units 3 & 4 (of which we are a 15 percent owner). The owners of Colstrip Units 3 & 4 have submitted the requested information and await the EPA's upcoming FIP proposal, which will include the EPA's determination of BART for Colstrip Units 3 & 4. We are unable to determine to what extent or if there will be any material impacts to Colstrip at this time.

Coal Ash Management/Disposal

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

Fisheries

A number of species of fish in the Northwest, including the Snake River sockeye salmon and fall chinook salmon, the Kootenai River white sturgeon, the upper Columbia River steelhead, the upper Columbia River spring chinook salmon and the bull trout, are listed as threatened or endangered under the Federal Endangered Species Act. Efforts to protect these and other species have not directly impacted generation levels at any of our hydroelectric facilities. We purchase power under long-term contracts with certain PUDs with hydroelectric generation projects on the Columbia River that are directly impacted by ongoing mitigation measures for salmon and steelhead. The reduction in generation at these projects is relatively minor, resulting in minimal economic impact on our operations at this time. We cannot predict the economic costs to us resulting from future mitigation measures. We received a 45-year FERC operating license for Cabinet Gorge and Noxon Rapids in March 2001 that incorporates a comprehensive settlement agreement. The restoration of native salmonid fish, including bull trout, is a key part of the agreement. The result is a collaborative native salmonid restoration program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana on the lower Clark Fork River, consistent with requirements of the FERC license. The U.S. Fish & Wildlife Service issued an updated Critical Habitat Designation for bull trout in 2010 that includes the lower Clark Fork River, as well as portions of the Coeur d'Alene basin within our Spokane River Project area, and is currently developing a final Bull Trout Recovery Plan under the ESA. Issues related to these activities are expected to be worked out through the ongoing collaborative effort of our Clark Fork and Spokane River FERC licenses. See "Hydroelectric Licensing" and "Fish Passage at Cabinet Gorge and Noxon Rapids" in "Note 21 of the Notes to 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 December 31, 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 21 of the Notes to Consolidated Financial Statements" for further information on the refund proceedings.

Other

For other environmental issues and other contingencies see "Note 21 of the Notes to Consolidated Financial Statements."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our primary market risk exposures are:

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

Commodity Price Risk

ELECTRIC POWER COMMODITIES

We are exposed to market risks for electric power because of:

- imbalances between available power supply resources and our load obligations,
- substitution of resources to achieve economic dispatch from available power supply choices, and
- our objective to optimize the value of specific power resource facilities.

Imbalances between available power supply resources and our electric load obligations arise because of seasonal factors, operating parameters of our facilities, contract rights and contract obligations, and variations in customer demand. We forecast both obligations and resources to estimate our future surplus or deficit positions. We hedge a portion of the open position with forward transactions that establish physical supply (or disposition) and/or financially-equivalent derivatives that mitigate economic uncertainty. Seasonal factors and prevailing weather affect power supplies. Supply is affected by both temperature and the timing and amount of precipitation, particularly with respect to our hydroelectric generation facilities that rely on river flows from immediate precipitation and from melting snow. Wind conditions affect the amount and timing of supply from wind generation facilities.

Operational parameters affecting power resources include natural river flow, water storage and regulation-driven constraints for hydroelectric generation. Operational parameters also include maintenance requirements and forced outages at electric generating plants, fuel availability for thermal plants, environmental and other regulatory constraints and other factors.

Electric power obligations include retail customer demand and other commitments between Avista Corp. and other parties in the wholesale power market. Retail customer demand is sensitive to temperature extremes and to normal seasonal temperature variation that impacts customers' heating and cooling-related demand for energy. Obligations are also affected by customer growth, economic conditions, technology that adds to or reduces electric demand, and choices that customers make about energy usage. Our forecasts of obligations consider contract terms, past energy demand patterns and indicators of potential changes in energy consumption.

Economic dispatch involves the decisions that we make in the mix of power resources to meet our retail customer requirements and other obligations. We make dispatch decisions to operate or not operate our resources and to dispose of energy or to obtain resources from others in the wholesale power market (including natural gas fuel markets). Hydroelectric generation is typically the lowest cost source of supply. Thermal generation resource costs vary with fuel costs and other factors. Power purchase agreements may provide us with variable power supply quantities and contract terms can include both fixed and variable costs.

To balance electric power resources and electric demand obligations, we enter into transactions in the wholesale power and fuel markets. These transactions include physical power and natural gas and derivative instruments based on wholesale prices of power and natural gas. Wholesale market prices tend to vary with natural gas fuel costs to the extent that natural gas-fired resources are the least cost alternative in the region (which is often the case in recent years). Wholesale prices also tend to vary with the extent of hydroelectric surplus or shortages, particularly during the highest hydroelectric generation periods of spring rains and snow melt. Wholesale prices also vary to a greater extent each year based on wind patterns as wind generation facilities have grown significantly in the region. Generating resource availability and regional demand tend to impact energy prices. Wholesale prices are quoted for energy to be delivered in time frames ranging from immediate real-time, to 30 minute, hourly, daily, multi-day, monthly, quarterly and annually. Future market prices extend several years into the future, though market liquidity tends to become limited beyond a few years into the future.

NATURAL GAS COMMODITIES

Natural gas is a significant source of fuel for electric generation. We buy natural gas as fuel for electric generating facilities that we own and for the Lancaster Plant where we have contractual rights to dispatch its operation. We also sell natural gas when we have an opportunity to displace thermal generation with other power supply resources or when expected thermal generation does not actually occur for any reason.

We hedge a portion of these natural gas purchases and sales, including the use of physical delivery contracts and derivative instruments based on wholesale prices of natural gas. We also transact based on index pricing in the wholesale natural gas market and at spot market prices that can vary significantly.

Some, but not all, natural gas transactions related to thermal generation are executed concurrently with similar quantities of electric energy (based on physical fuel-to-power conversion parameters of generation facilities that we own or control). In such cases, the net economic cost or benefit between natural gas purchases and power sales (or gas sales offset by power purchases) will vary as each commodity price moves independently of the other.

We also purchase natural gas for delivery to retail natural gas customers. Some natural gas is purchased for injection into storage, which can later be withdrawn from storage. To a lesser extent, we also sell natural gas originally purchased for retail natural gas supply or inventory back into the wholesale market. Some of the wholesale natural gas transactions are executed at fixed prices for future delivery, while some are executed based on market index prices or spot prices. We transact for physical delivery of natural gas and we enter into swaps that create a financial hedge for future natural gas prices.

We also enter into natural gas transactions intended to extract value from our assets and contract rights. These asset optimization transactions include purchases and offsetting sales at two delivery locations when we have excess capacity available in natural gas pipelines (such pipelines are usually owned by other parties where we have contract rights for that capacity). Asset optimization strategies also include time difference purchases and sales of natural gas that use excess storage capacity available in our underground natural gas storage facilities. These transactions include commitments for future physical delivery and/or financial swaps tied to the price of natural gas.

MATTERS AFFECTING BOTH ELECTRIC AND NATURAL GAS COMMODITIES

Variation in electric and natural gas commodity prices affects our cash flow, customer retail rates and the amount of net income we recognize. Regulatory cost recovery mechanisms address these power supply cost variations, such that a portion of the cost variation is passed on to customers and a portion is recognized by the Company. The timing of incurring costs can be significantly different than the timing for recovering costs, resulting in the need for a significant liquidity cushion. Historically, we have carried significant balances of deferred power supply and natural gas supply costs, which represent costs we expect to recover from customers in future retail rates, subject to approval by regulators.

When we have surplus electric generation, its value varies with market prices and economics of other resources in the region. When we have a shortage of electric generation from our own resources and other resources that we have long-term rights to control, the cost to obtain electric power or fuel varies. We make forecasts to estimate surplus and deficit conditions and we may enter into forward hedging arrangements to reduce the expected net surplus or deficit. Our forecasts cannot avoid uncertainty about loads or obligations and we do not attempt to fully hedge all forecast net open positions. Our hedges include forward transactions ranging from 30 minutes to multiple years in the future, with transaction blocks of 30 minute, hourly, daily, monthly, quarterly and annually. We are not able to predict how the combination of energy resources, energy loads, prices, rate recovery and other factors will ultimately drive deferred power costs and the timing of recovery of our costs in future periods. See further information at "Avista Utilities — Regulatory Matters."

See "Risk Management" for additional information on our activities to hedge our exposure to price risk by making forward commitments for energy purchases and sales.

Wholesale electricity prices are affected by a number of factors, including:

- demand for electricity,
- the number of market participants and the willingness of market participants to trade,
- adequacy of generating reserve margins,
- scheduled and unscheduled outages of generating facilities,
- availability of streamflows for hydroelectric generation,
- price and availability of fuel for thermal generating plants, and
- disruptions to or constraints on transmission facilities.

Wholesale natural gas prices are affected by a number of factors, including:

- overall actual and expected changes in the North American natural gas supply mix including the growth in unconventional supplies such as natural gas from shale,
- natural gas production that can be delivered to our service areas,
- level of imports and exports, particularly from Canada by pipeline,
- level of inventories and regional accessibility,
- demand for natural gas, including natural gas as fuel for electric generation,
- the number of market participants and the willingness of market participants to trade,
- global energy markets, including oil or other natural gas substitutes, and
- availability of pipeline capacity to transport natural gas from region to region.

Any combination of these factors that results in a shortage of energy generally causes the market price to move upward. Factors such as a general economic downturn, increased proven energy reserves, or increased production generally reduce market prices for energy. In addition to these factors, wholesale power markets are subject to regulatory constraints including price controls.

Price risk also includes the risk of fluctuation in the market price of associated derivative commodity instruments (such as options and forward contracts). Price risk may also be influenced to the extent that the performance or non-performance by market participants of their contractual obligations and commitments affect the supply of, or demand for, the commodity.

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 generally 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.

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 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
2012	$ (11,063)	$ (25,363)	$ (36,597)	$ (9,505)	$ 1,007	$ 7,206	$ 985	$ 3,647
2013	(2,479)	(12,021)	(15,112)	(12,989)	(38)	10,060	(1,073)	7,360
2014	(1,203)	(72)	(4,500)	(3,014)	(88)	1,347	(918)	(235)
2015	(1,186)	—	(1,014)	(435)	(114)	—	—	—
2016	(899)	—	(81)	46	(177)	—	—	—
Thereafter	(695)	—	—	—	(817)	—	—	—

Credit Risk

Credit risk relates to potential losses that we would incur as a result of non-performance of contractual obligations by counterparties to deliver energy or make financial settlements. We often extend credit to counterparties and customers, and we are exposed to the risk of not being able to collect amounts owed to us. Credit risk includes potential counterparty default due to circumstances:

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

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

We seek 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 some of our transactions on exchanges with fully collateralized clearing arrangements that significantly reduce counterparty default risk.

Our 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. We also use standardized agreements that allow for the netting or offsetting of positive and negative exposures associated with a single counterparty or affiliated group. However, despite mitigation efforts, the risk of default cannot be entirely eliminated.

We regularly evaluate counterparties' credit exposure for future settlements and delivery obligations. We reduce or eliminate open (unsecured) credit limits and implement other credit risk reduction measures for parties perceived to have increased default risk. Counterparty collateral is used to offset our credit risk where warranted in light of unsettled net positions and their future obligations to us.

We have concentrations of suppliers and customers in the electric and natural gas industries including:

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

In addition, we have concentrations of credit risk related to geographic location in the western United States and western Canada. These concentrations of counterparties and concentrations of geographic location may affect our overall exposure to credit risk because the counterparties may be similarly affected by changes in conditions.

Credit risk also involves demands on our capital. We are subject to limits and credit risks that counterparties perceive related to our ability to perform deliveries and settlement under physical and financial energy contracts. Many of our counterparties allow unsecured credit at limits prescribed by agreements or their discretion. Capital requirements for certain transaction types involve a combination of initial margin and market value margins without any unsecured credit threshold. Counterparties may seek assurances of performance from us in the form of letters of credit, prepayment or cash deposits.

Credit exposure can change significantly in periods of price volatility. As a result, sudden and significant demands may be made against our credit facilities and cash. We actively monitor the exposure to possible collateral calls and take steps to minimize capital requirements.

Counterparties' credit exposure to us is dynamic in normal markets and may change significantly in more volatile markets. The amount of potential default risk to us from each counterparty depends on the extent of forward contracts, unsettled transactions and market prices. There is a risk that we may seek additional collateral from counterparties that are unable or unwilling to provide it.

Risk Management for Energy Resources

We use a variety of techniques to manage risks for energy resources and wholesale energy market activities. We have an energy resources risk policy and control procedures to manage these risks, both qualitative and quantitative. Our Risk Management Committee has established our risk management policy for energy resources. The Risk Management Committee is comprised of certain officers and other management. The Audit Committee of the Company's Board of Directors periodically reviews and discusses enterprise risk management processes, and it focuses on the Company's material financial and accounting risk exposures and the steps management has undertaken to control them. Our Risk Management Committee reviews the status of risk exposures through regular reports and meetings. Nonetheless, adverse changes in commodity prices, generating capacity, customer loads, regulation and other factors may result in losses of earnings, cash flows and/or fair values.

Our Risk Management Committee has also established a wholesale energy markets credit policy. The credit policy is designed to reduce the risk of financial loss in case counterparties default on delivery or settlement obligations and to conserve our liquidity as other parties may place credit limits or require cash collateral.

In implementing our risk management policy for energy resources, we measure the volume of monthly, quarterly and annual energy imbalances between projected power loads and resources. The measurement process is based on expected loads at fixed prices (including those subject to retail rates) and expected resources to the extent that costs are essentially fixed by virtue of known fuel supply costs or projected hydroelectric conditions. To the extent that expected costs are not fixed, either because of volume mismatches between loads and resources or because fuel cost is not locked in through fixed price contracts or derivative instruments, our risk policy guides the process to manage this open forward position over a period of time. Normal operations result in seasonal mismatches between power loads and available resources. We are able to vary the operation of generating resources to match parts of 30 minute, hourly, daily and weekly load fluctuations. We use the wholesale power markets, including the natural gas market as it relates to power generation fuel, to sell projected resource surpluses and obtain resources when deficits are projected. We buy and sell fuel for thermal generation facilities based on comparative power market prices and marginal costs of fueling and operating available generating facilities and the relative economics of substitute market purchases for generating plant operation.

To address the impact on our operations of energy market price volatility, our hedging practices for electricity (including fuel for generation) and natural gas extend beyond the current operating year. Executing this extended hedging program may increase our credit risks. Our credit risk management process is designed to mitigate such credit risks through limit setting, contract protections and counterparty diversification, among other practices.

Electric load/resource imbalances within a planning horizon up to 41 months ahead are compared against established volumetric guidelines. Management determines the timing and actions to manage the imbalances. We also assess available resource alternatives and actions that are appropriate for longer-term planning periods. Expected load and resource volumes for forward periods are based on monthly and quarterly averages that may vary significantly from the actual loads and resources within any individual month or operating day. Future projections of resources are updated as forecasted streamflows and other factors differ from prior estimates. Forward power markets may be illiquid, and market products available may not match our desired transaction size and shape. Therefore, open imbalance positions exist at any given time.

Our projected natural gas loads and resources are regularly reviewed by operating management and the Risk Management Committee. To manage the impacts of volatile natural gas prices, we seek to procure natural gas through a diversified mix of spot market purchases and forward fixed price purchases from various supply basins and time periods. We have an active hedging program that extends four years into the future with the goal of reducing price volatility in our natural gas supply costs. We use natural gas storage capacity to support high demand periods and to procure natural gas when prices are likely to be seasonally lower. Securing prices throughout the year and even into subsequent years at multiple basins mitigates potential adverse impacts of significant purchase requirements in a volatile price environment.

Interest Rate Risk

We are affected by fluctuating interest rates related to a portion of our existing debt and our future borrowing requirements. We manage interest rate exposure by limiting our variable rate exposures to a percentage of total capitalization. Additionally, interest rate risk is managed by monitoring market conditions when timing the issuance of long-term debt and optional debt redemptions and through the use of fixed rate long-term debt with varying maturities. We also hedge a portion of our interest rate risk with financial derivative instruments, which may include interest rate swaps and U.S. Treasury lock agreements.

These interest rate swap agreements are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

As of December 31, 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 December 31, 2011, we had a derivative liability of $18.9 million and an offsetting regulatory asset on the 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.

We estimate that a 10-basis-point increase in forward LIBOR interest rates as of December 31, 2011 would decrease this derivative liability by $3.4 million, while a 10-basis-point decrease would increase the liability by $3.4 million.

The interest rate on $51.5 million of long-term debt to affiliated trusts is adjusted quarterly, reflecting current market rates. Amounts borrowed under our committed line of credit agreements have variable interest rates.

The following table shows our long-term debt (including current portion) and related weighted average interest rates, by expected maturity dates as of December 31, 2011 (dollars in thousands):

	2012	2013	2014	2015	2016	Thereafter	Total	Fair Value
Fixed rate long-term debt	$ 7,000	$ 50,000	—	—	—	$ 1,127,100	$ 1,184,100	$ 1,369,763
Weighted average interest rate	7.37%	1.68%	—	—	—	5.57%	5.42%	
Fixed rate nonrecourse long-term debt of Spokane Energy	$ 13,668	$ 14,965	$ 16,407	$ 1,431	—	—	$ 46,471	$ 51,974
Weighted average interest rate	8.45%	8.45%	8.45%	8.45%	—	—	8.45%	
Variable rate long-term debt to affiliated trusts	—	—	—	—	—	$ 51,547	$ 51,547	$ 43,810
Weighted average interest rate	—	—	—	—	—	1.40%	1.40%	

Foreign Currency Risk

A significant portion of our utility natural gas supply (including fuel for electric generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of our 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. We economically hedge a portion of the foreign currency risk by purchasing Canadian currency when such commodity transactions are initiated. This risk has not had a material effect on our 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. As of December 31, 2011, we had a current derivative asset for foreign currency hedges of $0.03 million included in other current assets on the Consolidated Balance Sheet. As of December 31, 2011, we had entered into 28 Canadian currency forward contracts with a notional amount of $7.0 million ($7.2 million Canadian).

Further information for derivatives and fair values is disclosed at "Note 6 of the Notes to Consolidated Financial Statements" and "Note 17 of the Notes to Consolidated Financial Statements."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Report of Independent Registered Public Accounting Firm and Financial Statements begin on the next page.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Avista Corporation
Spokane, Washington

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Avista Corporation and subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 2 to the consolidated financial statements, the Company has changed its method of accounting for variable interest entities effective January 1, 2010, due to the adoption of Accounting Standards Update No. 2009-17, *Consolidations — Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities.*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report, dated February 28, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 28, 2012

CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Years Ended December 31,

Dollars in thousands, except per share amounts

	2011	2010	2009
Operating Revenues:			
Utility revenues	$ 1,441,522	$ 1,417,846	$ 1,395,201
Non-utility revenues	178,258	140,894	117,364
Total operating revenues	1,619,780	1,558,740	1,512,565
Operating Expenses:			
Utility operating expenses:			
Resource costs	790,048	795,075	799,539
Other operating expenses	255,326	242,521	229,907
Depreciation and amortization	105,629	100,554	93,783
Taxes other than income taxes	83,349	73,392	76,583
Non-utility operating expenses:			
Other operating expenses	141,835	109,938	106,103
Depreciation and amortization	7,971	7,072	5,992
Total operating expenses	1,384,158	1,328,552	1,311,907
Income from operations	235,622	230,188	200,658
Interest expense	73,876	75,789	65,077
Interest expense to affiliated trusts	332	635	1,957
Capitalized interest	(2,942)	(298)	(545)
Other expense (income) — net	4,185	7,957	(802)
Income before income taxes	160,171	146,105	134,971
Income tax expense	56,632	51,157	46,323
Net income	103,539	94,948	88,648
Less: Net income attributable to noncontrolling interests	(3,315)	(2,523)	(1,577)
Net income attributable to Avista Corporation	$ 100,224	$ 92,425	$ 87,071
Weighted-average common shares outstanding (thousands), basic	57,872	55,595	54,694
Weighted-average common shares outstanding (thousands), diluted	58,092	55,824	54,942
Earnings per common share attributable to Avista Corporation:			
Basic	$ 1.73	$ 1.66	$ 1.59
Diluted	$ 1.72	$ 1.65	$ 1.58
Dividends paid per common share	$ 1.10	$ 1.00	$ 0.81

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

For the Years Ended December 31,

Dollars in thousands

	2011	2010	2009
Net income	$ 103,539	$ 94,948	$ 88,648
Other Comprehensive Income (Loss):			
Unrealized investment gains — net of taxes of $77	134	—	—
Change in unfunded benefit obligation for pension and other postretirement benefit plans — net of taxes of $(778), $(1,064) and $2,015, respectively	(1,445)	(1,976)	3,742
Total other comprehensive income (loss)	(1,311)	(1,976)	3,742
Comprehensive income	102,228	92,972	92,390
Comprehensive income attributable to noncontrolling interests	(3,315)	(2,523)	(1,577)
Comprehensive income attributable to Avista Corporation	$ 98,913	$ 90,449	$ 90,813

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS

Avista Corporation
As of December 31,
Dollars in thousands

	2011	2010
Assets:		
Current Assets:		
Cash and cash equivalents	$ 74,662	$ 69,413
Accounts and notes receivable — less allowances of $43,958 and $44,883	203,452	230,229
Utility energy commodity derivative assets	1,139	2,592
Regulatory asset for utility derivatives	69,685	48,891
Investments and funds held for clients	118,536	100,543
Materials and supplies, fuel stock and natural gas stored	52,006	48,530
Deferred income taxes	30,473	28,822
Income taxes receivable	15,378	19,069
Other current assets	49,225	31,476
Total current assets	614,556	579,565
Net Utility Property:		
Utility plant in service	3,887,384	3,713,885
Construction work in progress	79,322	62,051
Total	3,966,706	3,775,936
Less: Accumulated depreciation and amortization	1,105,930	1,061,699
Total net utility property	2,860,776	2,714,237
Other Non-current Assets:		
Investment in exchange power — net	18,783	21,233
Investment in affiliated trusts	11,547	11,547
Goodwill	39,045	25,935
Long-term energy contract receivable of Spokane Energy	62,525	62,525
Other intangibles, property and investments — net	80,309	74,553
Total other non-current assets	212,209	195,793
Deferred Charges:		
Regulatory assets for deferred income tax	84,576	90,025
Regulatory assets for pensions and other postretirement benefits	260,359	178,985
Other regulatory assets	119,738	112,830
Non-current utility energy commodity derivative assets	185	15,261
Non-current regulatory asset for utility derivatives	40,345	15,724
Power deferrals	—	18,305
Other deferred charges	21,787	19,370
Total deferred charges	526,990	450,500
Total assets	$ 4,214,531	$ 3,940,095

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS (CONTINUED)

Avista Corporation
As of December 31,
Dollars in thousands

	2011	2010
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 166,954	$ 171,707
Client fund obligations	118,325	100,543
Current portion of long-term debt	7,474	358
Current portion of nonrecourse long-term debt of Spokane Energy	13,668	12,463
Short-term borrowings	96,000	110,000
Utility energy commodity derivative liabilities	70,824	51,483
Natural gas deferrals	12,140	22,074
Other current liabilities	141,789	110,547
Total current liabilities	627,174	579,175
Long-term debt	1,169,826	1,101,499
Nonrecourse long-term debt of Spokane Energy	32,803	46,471
Long-term debt to affiliated trusts	51,547	51,547
Regulatory liability for utility plant retirement costs	227,282	223,131
Pensions and other postretirement benefits	246,177	161,189
Deferred income taxes	505,954	495,474
Other non-current liabilities and deferred credits	116,084	109,703
Total liabilities	2,976,847	2,768,189
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Redeemable Noncontrolling Interests	51,809	46,722
Equity:		
Avista Corporation Stockholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 58,422,781 and 57,119,723 shares outstanding	855,188	827,592
Accumulated other comprehensive loss	(5,637)	(4,326)
Retained earnings	336,150	302,518
Total Avista Corporation stockholders' equity	1,185,701	1,125,784
Noncontrolling Interests	174	(600)
Total equity	1,185,875	1,125,184
Total liabilities and equity	$ 4,214,531	$ 3,940,095

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation
For the Years Ended December 31,
Dollars in thousands

	2011	2010	2009
Operating Activities:			
Net income	$ 103,539	$ 94,948	$ 88,648
Non-cash items included in net income:			
Depreciation and amortization	113,600	107,626	99,775
Provision for deferred income taxes	24,007	37,734	13,853
Power and natural gas cost amortizations (deferrals), net	21,870	(9,795)	51,359
Amortization of debt expense	4,617	4,414	5,673
Amortization of investment in exchange power	2,450	2,450	2,450
Stock-based compensation expense	5,756	4,916	2,906
Equity-related AFUDC	(2,225)	(3,353)	(3,078)
Other	38,724	35,261	26,147
Payments for settlements with Coeur d'Alene Tribe	(2,000)	(4,000)	(12,000)
Contributions to defined benefit pension plan	(26,000)	(21,000)	(48,000)
Changes in working capital components:			
Accounts and notes receivable	30,616	(19,081)	14,659
Materials and supplies, fuel stock and natural gas stored	(3,388)	(11,248)	16,245
Other current assets	(23,881)	(9,230)	(3,528)
Accounts payable	(18,032)	13,606	(18,444)
Other current liabilities	(188)	5,189	22,116
Net cash provided by operating activities	269,465	228,437	258,781
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(239,782)	(202,227)	(205,384)
Other capital expenditures	(3,590)	(2,429)	(3,120)
Federal grant payments received	16,928	7,585	—
Cash paid by subsidiaries for acquisitions, net of cash received	(31,409)	(3,777)	(8,572)
Decrease (increase) in money market funds held for clients	78,561	(48,895)	8,507
Purchase of securities available for sale	(96,634)	—	—
Sale of securities available for sale	80	—	—
Other	(6,435)	(3,480)	(1,583)
Net cash used in investing activities	(282,281)	(253,223)	(210,152)

The Accompanying Notes are an Integral Part of These Statements.

Avista Corporation
For the Years Ended December 31,
Dollars in thousands

	2011	2010	2009
Financing Activities:			
Net increase (decrease) in short-term borrowings	$ (49,000)	$ 23,000	$ (159,500)
Borrowings from Ecova line of credit	35,000	2,300	—
Repayment of borrowings from Ecova line of credit	—	(8,000)	—
Proceeds from issuance of long-term debt	85,000	136,365	249,425
Redemption and maturity of long-term debt	(297)	(110,242)	(17,266)
Premiums paid for the redemption of long-term debt	—	(10,710)	—
Maturity of nonrecourse long-term debt of Spokane Energy	(12,463)	(11,370)	—
Redemption of long-term debt to affiliated trusts	—	—	(61,856)
Long-term debt and short-term borrowing issuance costs	(4,477)	(916)	(3,726)
Cash received (paid) for settlement of interest rate swap agreements	(10,557)	—	10,776
Issuance of common stock	26,463	46,235	2,622
Cash dividends paid	(63,737)	(55,682)	(44,360)
Purchase of subsidiary noncontrolling interest	(6,179)	(2,593)	(5,450)
Increase (decrease) in client fund obligations	17,782	48,895	(8,507)
Other	530	(118)	1,935
Net cash provided by (used in) financing activities	18,065	57,164	(35,907)
Net increase in cash and cash equivalents	5,249	32,378	12,722
Cash and cash equivalents at beginning of year	69,413	37,035	24,313
Cash and cash equivalents at end of year	$ 74,662	$ 69,413	$ 37,035
Supplemental Cash Flow Information:			
Cash paid during the year:			
Interest	$ 69,083	$ 74,195	$ 58,756
Income taxes	26,451	14,153	22,695
Non-cash financing and investing activities:			
Accounts payable for capital expenditures	20,629	8,315	8,404
Utility property acquired under capital leases	—	5,300	—
Redeemable noncontrolling interests	4,059	10,442	(400)
Contingent consideration by subsidiary for acquisition	—	1,134	—

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS

Avista Corporation

For the Years Ended December 31,

Dollars in thousands

	2011	2010	2009
Common Stock, Shares:			
Shares outstanding at beginning of year	57,119,723	54,836,781	54,487,574
Issuance of common stock through equity compensation plans	275,057	141,645	343,498
Issuance of common stock through Employee Investment Plan (401-K)	43,179	11,116	4,309
Issuance of common stock through Dividend Reinvestment Plan	177,822	76,071	1,400
Issuance of common stock	807,000	2,054,110	—
Shares outstanding at end of year	58,422,781	57,119,723	54,836,781
Common Stock, Amount:			
Balance at beginning of year	$ 827,592	$ 778,647	$ 774,986
Equity compensation expense.	3,635	3,097	2,711
Issuance of common stock through equity compensation plans	1,879	1,942	2,666
Issuance of common stock through Employee Investment Plan (401-K)	1,073	235	71
Issuance of common stock through Dividend Reinvestment Plan	4,299	1,451	26
Issuance of common stock, net of issuance costs	19,213	42,607	(141)
Equity transactions of consolidated subsidiaries	(2,503)	(387)	(1,672)
Balance at end of year	855,188	827,592	778,647
Accumulated Other Comprehensive Loss:			
Balance at beginning of year	(4,326)	(2,350)	(6,092)
Other comprehensive income (loss)	(1,311)	(1,976)	3,742
Balance at end of year	(5,637)	(4,326)	(2,350)
Retained Earnings:			
Balance at beginning of year	302,518	274,990	227,989
Net income attributable to Avista Corporation	100,224	92,425	87,071
Cash dividends paid (common stock)	(63,737)	(55,682)	(44,360)
Valuation adjustments and other noncontrolling interests activity	(2,855)	(9,215)	4,290
Balance at end of year	336,150	302,518	274,990
Total Avista Corporation stockholders' equity	1,185,701	1,125,784	1,051,287
Noncontrolling Interests:			
Balance at beginning of year	(600)	(673)	—
Net income (loss) attributable to noncontrolling interests	756	66	(295)
Other	18	7	(378)
Balance at end of year	174	(600)	(673)
Total equity	$ 1,185,875	$ 1,125,184	$ 1,050,614
Redeemable Noncontrolling Interests:			
Balance at beginning of year	$ 46,722	$ 34,833	$ 39,846
Net income attributable to noncontrolling interests	2,559	2,457	1,872
Purchase of subsidiary noncontrolling interests	(6,179)	(2,593)	(5,450)
Valuation adjustments and other noncontrolling interests activity	8,707	12,025	(1,435)
Balance at end of year	$ 51,809	$ 46,722	$ 34,833

The Accompanying Notes are an Integral Part of These Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corporation (Avista Corp. or the Company) 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 December 31, 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 24 for business segment information.

Basis of Reporting

The 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 consolidated financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (see Note 7).

Use of Estimates

The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP) requires management to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Significant estimates include:

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- recoverability of regulatory assets,
- stock-based compensation, and
- unbilled revenues.

Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on the consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein.

System of Accounts

The accounting records of the Company's utility operations are maintained in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by the state regulatory commissions in Washington, Idaho, Montana and Oregon.

Regulation

The Company is subject to state regulation in Washington, Idaho, Montana and Oregon. The Company is also subject to federal regulation primarily by the FERC, as well as various other federal agencies with regulatory oversight of particular aspects of its operations.

Utility Revenues

Utility revenues related to the sale of energy are recorded when service is rendered or energy is delivered to customers. Revenues and resource costs from Avista Utilities' settled energy contracts that are "booked out" (not physically delivered) are reported on a net basis as part of utility revenues. The determination of the energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, the amount of energy delivered to customers since the date of the last meter reading is estimated and the corresponding unbilled revenue is estimated and recorded.

Accounts receivable includes unbilled energy revenues of the following amounts as of December 31 (dollars in thousands):

	2011	2010
Unbilled accounts receivable	$ 82,950	$ 84,073

Non-Utility Revenues

Service revenues from Ecova are recognized over the period services are rendered. New client account setup fees are deferred and recognized over the contractual life of the related client contract. Investment earnings on funds held for clients and fees earned from third parties on payment processing are an integral part of Ecova's product offerings and are recognized in revenues as earned. Revenue arrangements with multiple elements are divided into separate units of accounting if certain criteria are met, including whether the delivered element has stand-alone value to the customer and whether there is objective and reliable evidence of the fair value of the undelivered items. The consideration received is allocated among the separate units based on their respective fair values, and the applicable revenue recognition criteria are applied to each of the separate units. Revenues earned on payment processing through other service providers are reported gross on the income statement. Revenues from the other businesses are primarily derived from the operations of Advanced Manufacturing and Development (doing business as METALfx) and are recognized when the risk of loss transfers to the customer, which occurs when products are shipped.

Advertising Expenses

The Company expenses advertising costs as incurred. Advertising expenses were not a material portion of the Company's operating expenses in 2011, 2010 and 2009.

Depreciation

For utility operations, depreciation expense is estimated by a method of depreciation accounting utilizing composite rates for utility plant. Such rates are designed to provide for retirements of properties at the expiration of their service lives.

For utility operations, the ratio of depreciation provisions to average depreciable property was as follows for the years ended December 31:

	2011	2010	2009
Ratio of depreciation to average depreciable property	2.92%	2.84%	2.78%

The average service lives for the following broad categories of utility plant in service are:

- electric thermal production — 33 years,
- hydroelectric production — 74 years,
- electric transmission — 51 years,
- electric distribution — 38 years, and
- natural gas distribution property — 49 years.

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 years ended December 31 (dollars in thousands):

	2011	2010	2009
Utility taxes	$ 55,739	$ 49,953	$ 56,818

Allowance for Funds Used During Construction

The Allowance for Funds Used During Construction (AFUDC) represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. As prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant and the debt related portion is credited against total interest expense in the Consolidated Statements of Income in the line item "capitalized interest." The equity related portion of AFUDC is included in the Consolidated Statement of Income in the line item "other expense (income) — net." The Company is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a reasonable return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant is placed in service. Cash inflow related to AFUDC does not occur until the related utility plant is placed in service and included in rate base.

The effective AFUDC rate was the following for the years ended December 31:

	2011	2010	2009
Effective AFUDC rate	7.91%	8.25% (1)	8.22%

(1) Rate was effective from January 1, 2010 to November 30, 2010. Effective December 1, 2010, rate was changed to 7.91%.

Income Taxes

A deferred income tax asset or liability is determined based on the enacted tax rates that will be in effect when the differences between the financial statement carrying amounts and tax basis of existing assets and liabilities are expected to be reported in the Company's consolidated income tax returns. The deferred income tax expense for the period is equal to the net change in the deferred income tax asset and liability accounts from the beginning to the end of the period. The effect on deferred income taxes from a change in tax rates is recognized in income in the period that includes the enactment date. Deferred income tax liabilities and regulatory assets are established for income tax benefits flowed through to customers as prescribed by the respective regulatory commissions.

Stock-Based Compensation

Compensation cost relating to share-based payment transactions is recognized in the Company's financial statements based on the fair value of the equity or liability instruments issued and recorded over the requisite service period. See Note 20 for further information.

Other Expense (Income) — Net

Other expense (income) — net consisted of the following items for the years ended December 31 (dollars in thousands):

	2011	2010	2009
Interest income	$ (1,327)	$ (1,159)	$ (1,614)
Interest on regulatory deferrals	(89)	(248)	(2,935)
Equity-related AFUDC	(2,225)	(3,353)	(3,078)
Net loss on investments	488	3,297	837
Dues and donations	2,143	4,164	1,405
Other expense	5,213	5,686	5,472
Other income	(18)	(430)	(889)
Total	$ 4,185	$ 7,957	$ (802)

Earnings per Common Share Attributable to Avista Corporation

Basic earnings per common share attributable to Avista Corporation is computed by dividing net income attributable to Avista Corporation by the weighted average number of common shares outstanding for the period. Diluted earnings per common share attributable to Avista Corporation is calculated by dividing net income attributable to Avista Corporation (adjusted for the effect of potentially dilutive securities issued by subsidiaries) by diluted weighted average common shares outstanding during the period, including common stock equivalent shares outstanding using the treasury stock method, unless such shares are anti-dilutive. Common stock equivalent shares include shares issuable upon exercise of stock options and contingent stock awards. See Note 19 for earnings per common share calculations.

Cash and Cash Equivalents

For the purposes of the Consolidated Statements of Cash Flows, the Company considers all temporary investments with a maturity of three months or less when purchased to be cash equivalents. Cash and cash equivalents include cash deposits from counterparties.

Allowance for Doubtful Accounts

The Company maintains an allowance for doubtful accounts to provide for estimated and potential losses on accounts receivable. The Company determines the allowance for utility and other customer accounts receivable based on historical write-offs as compared to accounts receivable and operating revenues. Additionally, the Company establishes specific allowances for certain individual accounts.

The following table presents the activity in the allowance for doubtful accounts during the years ended December 31 (dollars in thousands):

	2011	2010	2009
Allowance as of the beginning of the year	$ 44,883	$ 42,928	$ 45,062
Additions expensed during the year	5,232	5,194	5,344
Net deductions	(6,157)	(3,239)	(7,478)
Allowance as of the end of the year	$ 43,958	$ 44,883	$ 42,928

Materials and Supplies, Fuel Stock and Natural Gas Stored

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

	2011	2010
Materials and supplies	$ 24,148	$ 24,998
Fuel stock	4,248	6,289
Natural gas stored	23,610	17,243
Total	$ 52,006	$ 48,530

Investments and Funds Held for Clients and Client Fund Obligations

In connection with the bill paying services, Ecova collects funds from its clients and remits the funds to the appropriate utility or other service provider. The funds collected are invested and classified as investments and funds held for clients and a related liability for client fund obligations is recorded. Investments and funds held for clients include cash and cash equivalent investments and beginning in 2011, investment securities classified as available for sale.

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

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

All investments and funds held for clients at December 31, 2010 were in money market funds. The Company has classified investments and funds held for clients as a current asset since these funds are held solely for the purpose of satisfying the client fund obligations. Approximately 88 percent of the investment portfolio is rated AA or higher as of December 31, 2011 by Nationally Recognized Statistical Rating Organizations. All fixed income securities were rated as investment grade as of December 31, 2011. Based on the Company's analysis, securities available for sale do not meet the criteria for other-than-temporary impairment as of December 31, 2011.

Contractual maturities of securities available for sale as of December 31, 2011 are as follows (dollars in thousands):

	Due within 1 year	After 1 but within 5 years	After 5 but within 10 years	Total
Maturity date	$ 425	$ 55,126	$ 41,028	$ 96,579

Utility Plant in Service

The cost of additions to utility plant in service, including an allowance for funds used during construction and replacements of units of property and improvements, is capitalized. The cost of depreciable units of property retired plus the cost of removal less salvage is charged to accumulated depreciation.

Asset Retirement Obligations

The Company recovers certain asset retirement costs through rates charged to customers as a portion of its depreciation expense for which the Company has not recorded asset retirement obligations (see Note 9).

The Company had estimated retirement costs (that do not represent legal or contractual obligations) included as a regulatory liability on the Consolidated Balance Sheets of the following amounts as of December 31 (dollars in thousands):

	2011	2010
Regulatory liability for utility plant retirement costs	$ 227,282	$ 223,131

Goodwill

Goodwill arising from acquisitions represents the excess of the purchase price over the estimated fair value of net assets acquired. The Company evaluates goodwill for impairment using a discounted cash flow model on at least an annual basis or more frequently if impairment indicators arise. The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2011 for the other businesses and as of December 31, 2011 for Ecova and determined that goodwill was not impaired at that time.

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

	Ecova	Other	Accumulated Impairment Losses	Total
Balance as of January 1, 2010	$ 19,472	$ 12,979	$ (7,733)	$ 24,718
Goodwill acquired during the year	1,113	—	—	1,113
Adjustments	104	—	—	104
Balance as of December 31, 2010	20,689	12,979	(7,733)	25,935
Goodwill acquired during the year	12,933	—	—	12,933
Adjustments	177	—	—	177
Balance as of December 31, 2011	$ 33,799	$ 12,979	$ (7,733)	$ 39,045

Accumulated impairment losses are attributable to the other businesses. The goodwill acquired in 2010 was related to Ecova's acquisition of The Loyalton Group (Loyalton) on December 31, 2010. The goodwill acquired in 2011 was related to Ecova's acquisition of Prenova, Inc. (Prenova) on November 30, 2011.

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), Loyalton in 2010 (estimated amortization period of 6 years) and Prenova in 2011 (estimated amortization period of 9 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 Consolidated Balance Sheets.

Amortization expense related to Other Intangibles was as follows for the years ended December 31 (dollars in thousands):

	2011	2010	2009
Other intangible amortization	$ 4,682	$ 3,755	$ 2,412

The following table details the future estimated amortization expense related to Other Intangibles (dollars in thousands):

	2012	2013	2014	2015	2016
Estimated amortization expense	$ 7,809	$ 7,374	$ 6,324	$ 3,396	$ 2,761

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

	2011	2010
Client relationships	$ 18,859	$ 11,459
Software development costs	29,327	19,139
Other	3,065	1,450
Total other intangibles	51,251	32,048
Client relationships accumulated amortization	(3,623)	(2,156)
Software development costs accumulated amortization	(12,016)	(8,985)
Other accumulated amortization	(990)	(806)
Total accumulated amortization	(16,629)	(11,947)
Total other intangibles — net	$ 34,622	$ 20,101

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the 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 Consolidated Statements of Income. Realized gains or losses are recognized in the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rates cases. Regulatory assets are assessed regularly and are probable for recovery through future rates.

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

Fair Value Measurements

Fair value represents the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Energy commodity derivative assets and liabilities, investments and funds held for clients, deferred compensation assets, as well as derivatives related to interest rate swap agreements and foreign currency exchange contracts, are reported at estimated fair value on the Consolidated Balance Sheets. See Note 17 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits

The Company prepares its 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 Consolidated Balance Sheets. These costs and/or obligations are not reflected in the Consolidated Statements of Income until the period during which matching revenues are recognized. If at some point in the future the

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

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

See Note 23 for further details of regulatory assets and liabilities.

Investment in Exchange Power — Net

The investment in exchange power represents the Company's previous investment in Washington Public Power Supply System Project 3 (WNP-3), a nuclear project that was terminated prior to completion. Under a settlement agreement with the Bonneville Power Administration in 1985, Avista Utilities began receiving power in 1987, for a 32.5-year period, related to its investment in WNP-3. Through a settlement agreement with the WUTC in the Washington jurisdiction, Avista Utilities is amortizing the recoverable portion of its investment in WNP-3 (recorded as investment in exchange power) over a 32.5-year period that began in 1987. For the Idaho jurisdiction, Avista Utilities fully amortized the recoverable portion of its investment in exchange power.

Unamortized Debt Expense

Unamortized debt expense includes debt issuance costs that are amortized over the life of the related debt.

Unamortized Debt Repurchase Costs

For the Company's Washington regulatory jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums paid to repurchase debt are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. In the Company's other regulatory jurisdictions, premiums paid to repurchase debt prior to 2007 are being amortized over the average remaining maturity of outstanding debt when no new debt was issued in connection with the debt repurchase. These costs are recovered through retail rates as a component of interest expense.

Redeemable Noncontrolling Interests

This item represents the estimated fair value of redeemable stock and stock options of Ecova issued under its employee stock incentive plan and to the previous owners of Cadence Network. See Notes 5 and 20 for further information.

Accumulated Other Comprehensive Loss

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

	2011	2010
Unfunded benefit obligation for pensions and other postretirement benefit plans	$ (5,771)	$ (4,326)
Unrealized gain on securities available for sale	134	—
Total accumulated other comprehensive loss	$ (5,637)	$ (4,326)

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. 2009-16, "Transfers and Servicing" (ASC Topic 860). This ASU amends certain provisions of ASC 860 related to accounting for transfers of financial assets and a transferor's continuing involvement in transferred financial assets. The adoption of this ASU did not have any impact on the Company's financial condition, results of operations and cash flows.

Effective January 1, 2010, the Company adopted ASU No. 2009-17, "Consolidations (Topic 810) — Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities (VIEs)." This ASU carries forward the scope of ASC 810, with the addition of entities previously considered qualifying special-purpose entities, as the concept of these entities was eliminated in ASU No. 2009-16 (ASC 860). The amendments required the Company to reconsider previous conclusions relating to the consolidation of VIEs, whether the Company is the VIE's primary beneficiary, and what type of financial statement disclosures are required. See Note 3 for further information.

Effective January 1, 2010, the Company adopted 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 was required beginning in 2011). See Note 17 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 does not expect that this ASU will have material impact on its financial condition, results of operations and cash flows.

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 does not expect that this ASU will have any material impact on its testing of goodwill for impairment.

NOTE 3. VARIABLE INTEREST ENTITIES

The Company has a power purchase agreement (PPA) for the purchase of all the output of the Lancaster Plant, a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho, owned by an unrelated third-party (Rathdrum Power LLC), through 2026. Beginning in July 2007 through the end of 2009, the majority of the rights and obligations under the PPA were conveyed to Shell Energy in connection with the sale of the majority of Avista Energy's contracts and ongoing operations to Shell Energy. These rights and obligations were conveyed to Avista Corp. (Avista Utilities) beginning in January 2010. Effective December 1, 2010, the rights and obligations under the PPA were assigned to Avista Corp.

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 consolidated financial statements. The Company has a future contractual obligation of approximately $341 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.

The implementation of amendments to ASC 810 resulted in the Company including Spokane Energy, LLC (Spokane Energy) in its consolidated financial statements effective January 1, 2010. 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.

Ecova formed a partnership, SEEL, LLC (SEEL) with a third party for the purpose of entering into utility contracts to provide energy efficiency services. SEEL is funded 49 percent by Ecova and 51 percent by the third party. Ecova determined that it was the primary beneficiary of SEEL based on its management of the entity and its technical expertise in obtaining and fulfilling the utility contracts and Ecova is obligated to absorb the losses or receive the benefits that could be significant to SEEL. In 2011, the Consolidated Statement of Income reflects operating revenues of $3.2 million (included in non-utility revenues), operating expenses of $1.9 million (included in non-utility operating expenses) and net income attributable to noncontrolling interests of $0.7 million related to SEEL. The assets and liabilities of SEEL are not material to the Company's Consolidated Balance Sheet.

NOTE 4. IMPAIRMENT OF ASSETS

During the fourth quarter of 2009, the Company recorded a $3.0 million impairment charge for a commercial building (included in its other businesses). This impairment charge is included in non-utility other operating expenses in the Consolidated Statements of Income. Due to an increase in vacancy rates and a reduction in current and projected cash flows, the Company determined that it needed to evaluate the property for impairment. The impairment charge reduced the carrying value of the commercial building to its estimated fair value, which was $2.7 million. The estimated fair value of the commercial building was determined using a discounted cash flow model with Level 3 inputs. See Note 17 for a discussion of the fair value hierarchy.

NOTE 5. 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. These 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 (refer to Note 20 for further information).

The following details redeemable noncontrolling interests as of December 31 (dollars in thousands):

	2011	2010
Previous owners of Cadence Network	$ 38,893	$ 38,098
Stock options and other outstanding redeemable stock	12,916	8,624
Total redeemable noncontrolling interests	$ 51,809	$ 46,722

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

On August 31, 2009, Ecova acquired substantially all of the assets and liabilities of Ecos Consulting, Inc. (Ecos), a Portland, Oregon-based energy efficiency solutions provider. The acquisition of Ecos was funded primarily through borrowings under Ecova's committed credit agreement. Under the terms of the transaction, the assets and liabilities of Ecos were acquired by a wholly owned subsidiary of Ecova. The acquired assets and liabilities assumed of Ecos were recorded at their respective estimated fair values as of the date of acquisition (August 31, 2009). The results of operations of Ecos are included in the consolidated financial statements beginning in September 2009.

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 consolidated financial statements beginning January 1, 2011.

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

On November 30, 2011, Ecova acquired all of the capital stock of Prenova, Inc. (Prenova), an Atlanta-based energy management company. The cash paid for the acquisition of Prenova of $35.6 million was funded primarily through borrowings under Ecova's committed credit agreement. The acquired assets and assumed liabilities of Prenova were recorded at their respective estimated fair values as of the date of acquisition. Assets recorded include the following: accounts receivable of $2.4 million, deferred income tax assets of $3.7 million, goodwill of $12.9 million, client relationships of $7.4 million (estimated amortization period of 9 years) and internal use software of $5.4 million (estimated amortization period of 5 to 6 years). These intangible assets are included in other intangibles, property and investments on the Consolidated Balance Sheet. Final purchase accounting is pending the completion of further review of the fair market values of relevant assets and liabilities identified as of the acquisition date. The results of operations of Prenova are included in the consolidated financial statements beginning December 1, 2011.

In January 2012, Ecova acquired all of the capital stock of LPB Energy Management (LPB), a Dallas, Texas-based energy management company. The cash paid for the acquisition of LPB of $50.3 million was funded by Ecova through $25.0 million of borrowings under its committed credit agreement, a $20.0 million equity infusion from existing shareholders (including Avista Capital and the other owners of Ecova), and available cash. Ecova is in the process of estimating the fair value of the acquired assets and liabilities assumed of LPB as of the date of acquisition.

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

NOTE 6. 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 enterprise risk management processes, and it focuses on the Company's material financial and accounting risk exposures and the steps management has undertaken to control them.

As part of its resource procurement and management operations in the electric business, Avista Utilities engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Utilities' load obligations and the use of these resources to capture available economic value. Avista Utilities sells and purchases wholesale electric capacity and energy and fuel as part of the process of acquiring and balancing resources to serve its load obligations. These transactions range from terms of 30 minutes up to multiple years.

Avista Utilities makes continuing projections of:

- electric loads at various points in time (ranging from 30 minutes to multiple years) based on, among other things, estimates of customer usage and weather, historical data and contract terms, and
- resource availability at these points in time based on, among other things, fuel choices and fuel markets, estimates of streamflows, availability of generating units, historic and forward market information, contract terms, and experience.

On the basis of these projections, Avista Utilities makes purchases and sales of electric capacity and energy and fuel to match expected resources to expected electric load requirements. Resource optimization involves generating plant dispatch and scheduling available resources and also includes transactions such as:

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

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

As part of its resource procurement and management 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
- purchases and sales of natural gas to optimize use of storage capacity.

The following table presents the underlying energy commodity derivative volumes as of December 31, 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
2012	1,021	2,181	39,547	78,575	613	1,398	4,261	71,913
2013	398	1,874	11,742	61,357	254	1,781	1,532	52,817
2014	366	30	5,562	22,328	286	737	1,050	8,900
2015	379	—	2,635	1,502	286	—	—	—
2016	367	—	910	227	287	—	—	—
Thereafter	949	—	—	—	730	—	—	—

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 December 31 (dollars in thousands):

	2011	2010
Number of contracts	28	29
Notional amount (in United States dollars)	$ 7,033	$ 10,916
Notional amount (in Canadian dollars)	7,192	10,989
Derivatives in other current assets	32	116

Interest Rate Swap Agreements

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

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

	2011	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	(18,895)	(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 14). Upon settlement of the interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the life of the forecasted interest payments.

Derivative Instruments Summary

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

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

The following table presents the fair values and locations of derivative instruments recorded on the 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 December 31, 2011, the Company had cash deposited as collateral of $18.2 million and letters of credit of $18.8 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 December 31, 2011 was $154.9 million. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2011, the Company could be required to post $61.3 million of collateral to its counterparties.

Credit Risk

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

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

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

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

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

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

The Company maintains 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 7. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, the Colstrip Generating Project (Colstrip) located in southeastern Montana, and provides financing for its ownership interest in the project. The Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Consolidated Statements of Income.

The Company's share of utility plant in service for Colstrip and accumulated depreciation were as follows as of December 31 (dollars in thousands):

	2011	2010
Utility plant in service	$ 342,539	$ 336,796
Accumulated depreciation	(225,746)	(219,770)

NOTE 8. PROPERTY, PLANT AND EQUIPMENT

The balances of the major classifications of property, plant and equipment are detailed in the following table as of December 31 (dollars in thousands):

	2011	2010
Avista Utilities:		
Electric production	$ 1,094,223	$ 1,076,829
Electric transmission	522,930	496,495
Electric distribution	1,157,012	1,084,082
Electric construction work-in-progress (CWIP) and other	205,437	183,479
Electric total	2,979,602	2,840,885
Natural gas underground storage	40,430	32,928
Natural gas distribution	683,948	653,075
Natural gas CWIP and other	41,077	56,899
Natural gas total	765,455	742,902
Common plant (including CWIP)	221,649	192,149
Total Avista Utilities	3,966,706	3,775,936
Ecova (1)	25,763	27,222
Other (1)	22,042	36,962
Total	$ 4,014,511	$ 3,840,120

(1) Included in other intangibles, property and investments — net on the Consolidated Balance Sheets. Accumulated depreciation was $20.3 million as of December 31, 2011 and $22.4 million as of December 31, 2010 for Ecova and $13.1 million as of December 31, 2011 and $16.6 million as of December 31, 2010 for the other businesses.

NOTE 9. ASSET RETIREMENT OBLIGATIONS

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the associated costs of the asset retirement obligation are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. Upon retirement of the asset, the Company either settles the retirement obligation for its recorded amount or incurs a gain or loss. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and asset retirement obligations recorded since asset retirement costs are recovered through rates charged to customers. The regulatory assets do not earn a return.

Specifically, the Company has recorded liabilities for future asset retirement obligations to:

- restore ponds at Colstrip,
- cap a landfill at the Kettle Falls Plant,
- remove plant and restore the land at the Coyote Springs 2 site at the termination of the land lease,
- remove asbestos at the corporate office building, and
- dispose of PCBs in certain transformers.

Due to an inability to estimate a range of settlement dates, the Company cannot estimate a liability for the:

- removal and disposal of certain transmission and distribution assets, and
- abandonment and decommissioning of certain hydroelectric generation and natural gas storage facilities.

The following table documents the changes in the Company's asset retirement obligation during the years ended December 31 (dollars in thousands):

	2011	2010	2009
Asset retirement obligation at beginning of year	$ 3,887	$ 3,971	$ 4,208
New liability recognized	—	19	—
Liability settled	(612)	(460)	(499)
Accretion expense	238	357	262
Asset retirement obligation at end of year	$ 3,513	$ 3,887	$ 3,971

NOTE 10. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering substantially all regular full-time employees at Avista Utilities. Individual benefits under this plan are based upon the employee's years of service, date of hire and average compensation as specified in the plan. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $26 million in cash to the pension plan in 2011, $21 million in 2010 and $48 million in 2009. The Company expects to contribute $44 million in cash to the pension plan in 2012.

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

The Company expects that benefit payments under the pension plan and the SERP will total (dollars in thousands):

	2012	2013	2014	2015	2016	Total 2017–2021
Expected benefit payments	$ 20,484	$ 21,899	$ 23,189	$ 24,759	$ 26,100	$ 154,146

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. In selecting a discount rate, the Company considers yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits.

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 elected to amortize the transition obligation of $34.5 million over a period of 20 years, beginning in 1993.

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

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

The Company expects that benefit payments under other postretirement benefit plans will total (dollars in thousands):

	2012	2013	2014	2015	2016	Total 2017–2021
Expected benefit payments	$ 5,277	$ 5,390	$ 5,523	$ 5,735	$ 5,946	$ 32,231

The Company expects to contribute $5.3 million to other postretirement benefit plans in 2012, representing expected benefit payments to be paid during the year. The Company uses a December 31 measurement date for its pension and other postretirement benefit plans.

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2011 and 2010 and the components of net periodic benefit costs for the years ended December 31, 2011, 2010 and 2009 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2011	2010	2011	2010
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 433,491	$ 378,235	$ 60,339	$ 39,560
Service cost	12,936	11,609	1,805	684
Interest cost	24,134	23,231	4,126	2,624
Actuarial loss	44,148	38,547	42,476	21,657
Transfer of accrued vacation	—	—	450	367
Benefits paid	(20,517)	(18,131)	(4,466)	(4,553)
Benefit obligation as of end of year	$ 494,192	$ 433,491	$ 104,730	$ 60,339
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 306,712	$ 272,732	$ 22,875	$ 20,394
Actual return on plan assets	14,705	29,846	(420)	2,481
Employer contributions	26,000	21,000	—	—
Benefits paid	(19,267)	(16,866)	—	—
Fair value of plan assets as of end of year	$ 328,150	$ 306,712	$ 22,455	$ 22,875
Funded status	$ (166,042)	$ (126,779)	$ (82,275)	$ (37,464)
Unrecognized net actuarial loss	192,883	149,819	76,187	35,149
Unrecognized prior service cost	665	1,140	(1,005)	(1,154)
Unrecognized net transition obligation	—	—	505	1,011
Prepaid (accrued) benefit cost	27,506	24,180	(6,588)	(2,458)
Additional liability	(193,548)	(150,959)	(75,687)	(35,006)
Accrued benefit liability	$ (166,042)	$ (126,779)	$ (82,275)	$ (37,464)
Accumulated pension benefit obligation	$ 429,135	$ 377,606	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 39,470	$ 27,921
For fully eligible employees			$ 29,597	$ 15,618
For other participants			$ 35,663	$ 16,800
Included in accumulated comprehensive loss (income) (net of tax):				
Unrecognized net transition obligation	$ —	$ —	$ 328	$ 657
Unrecognized prior service cost	433	741	(653)	(750)
Unrecognized net actuarial loss	125,374	97,382	49,522	22,847
Total	125,807	98,123	49,197	22,754
Less regulatory asset	(119,360)	(92,570)	(49,873)	(23,981)
Accumulated other comprehensive loss (income)	$ 6,447	$ 5,553	$ (676)	$ (1,227)

	Pension Benefits 2011	Pension Benefits 2010	Other Post-retirement Benefits 2011	Other Post-retirement Benefits 2010
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	5.04%	5.69%	4.98%	5.50%
Discount rate for annual expense	5.68%	6.28%	5.53%	6.00%
Expected long-term return on plan assets	7.40%	7.75%	7.00%	7.75%
Rate of compensation increase	4.87%	4.72%		
Medical cost trend pre-age 65 — initial			7.50%	8.00%
Medical cost trend pre-age 65 — ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2017	2017
Medical cost trend post-age 65 — initial			8.00%	8.00%
Medical cost trend post-age 65 — ultimate			6.00%	6.00%
Ultimate medical cost trend year post-age 65			2018	2015

	Pension Benefits 2011	Pension Benefits 2010	Pension Benefits 2009	Other Post-retirement Benefits 2011	Other Post-retirement Benefits 2010	Other Post-retirement Benefits 2009
Components of net periodic benefit cost:						
Service cost	$ 12,936	$ 11,609	$ 10,496	$ 1,805	$ 684	$ 803
Interest cost	24,134	23,231	21,770	4,126	2,624	2,364
Expected return on plan assets	(23,115)	(21,381)	(17,612)	(1,601)	(1,581)	(1,364)
Transition obligation recognition	—	—	—	505	505	505
Amortization of prior service cost	475	650	654	(149)	(149)	(149)
Net loss recognition	9,493	7,189	10,539	3,458	1,379	1,279
Net periodic benefit cost	$ 23,923	$ 21,298	$ 25,847	$ 8,144	$ 3,462	$ 3,438

Plan Assets

The Finance Committee of the Company's Board of Directors establishes investment policies, objectives and strategies that seek an appropriate return for the pension plan and other postretirement benefit plans and reviews and approves changes to the investment and funding policies.

The Company has contracted with investment consultants who are responsible for managing/monitoring the individual investment managers. The investment managers' performance and related individual fund performance is periodically reviewed by an internal benefits committee and by the Finance Committee to monitor compliance with investment policy objectives and strategies.

Pension plan assets are invested primarily in marketable debt and equity securities. Pension plan assets may also be invested in real estate, absolute return, venture capital/private equity and commodity funds. In seeking to obtain the desired return to fund the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee.

The Finance Committee has established target investment allocation percentages by asset classes as indicated in the table below:

	2011	2010
Equity securities	51%	51%
Debt securities	31%	31%
Real estate	5%	5%
Absolute return	10%	10%
Other	3%	3%

The market-related value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). Investments in common/collective trust funds are presented at estimated fair value, which is determined based on the unit value of the fund. Unit value is determined by an independent trustee, which sponsors the fund, by dividing the fund's net assets by its units outstanding at the valuation date. The fair value of the closely held investments and partnership interests is based upon the allocated share of the fair value of the underlying assets as well as the allocated share of the undistributed profits and losses, including realized and unrealized gains and losses.

The market-related value of pension plan assets invested in real estate was determined by the investment manager based on three basic approaches:

- properties are externally appraised on an annual basis by independent appraisers, additional appraisals may be performed as warranted by specific asset or market conditions,
- property valuations are reviewed quarterly and adjusted as necessary, and
- loans are reflected at fair value.

The market-related value of pension plan assets was determined as of December 31, 2011 and 2010.

The following table discloses by level within the fair value hierarchy (refer to Note 17 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2011 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 7,550	$ —	$ 7,550
Mutual funds:				
Fixed income securities	76,486	—	—	76,486
U.S. equity securities	102,790	—	—	102,790
International equity securities	52,241	—	—	52,241
Absolute return (1)	16,121	—	—	16,121
Commodities (2)	6,526	—	—	6,526
Common/collective trusts:				
Fixed income securities	—	27,774	—	27,774
U.S. equity securities	—	12,669	—	12,669
Real estate	—	—	8,598	8,598
Partnership/closely held investments:				
Absolute return (1)	—	—	16,587	16,587
Private equity funds (3)	—	—	808	808
Total	$ 254,164	$ 47,993	$ 25,993	$ 328,150

The following table discloses by level within the fair value hierarchy (refer to Note 17 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2010 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 335	$ —	$ —	$ 335
Mutual funds:				
Fixed income securities	96,026	—	—	96,026
U.S. equity securities	104,232	—	—	104,232
International equity securities	53,964	—	—	53,964
Absolute return (1)	12,662	—	—	12,662
Commodities (2)	7,133	—	—	7,133
Common/collective trusts:				
U.S. equity securities	—	13,653	—	13,653
Absolute return (1)	—	—	95	95
Real estate	—	—	423	423
Partnership/closely held investments:				
Absolute return (1)	—	—	16,917	16,917
Private equity funds (3)	—	—	1,272	1,272
Total	$ 274,352	$ 13,653	$ 18,707	$ 306,712

(1) This category invests in multiple strategies to diversify risk and reduce volatility. The strategies include: (a) event driven, relative value, convertible, and fixed income arbitrage, (b) distressed investments, (c) long/short equity and fixed income, and (d) market neutral strategies.

(2) The fund primarily invests in derivatives linked to commodity indices to gain exposure to the commodity markets. The fund manager fully collateralizes these positions with debt securities.

(3) This category includes private equity funds that invest primarily in U.S. companies.

The table below discloses the summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2011 (dollars in thousands):

	Common/collective trusts		Partnership/closely held investments	
	Absolute return	Real estate	Absolute return	Private equity funds
Balance, as of January 1, 2011	$ 95	$ 423	$ 16,917	$ 1,272
Realized gains (losses)	(748)	22	—	373
Unrealized gains (losses)	746	1,098	(330)	(218)
Purchases (sales), net	(93)	7,055	—	(619)
Balance, as of December 31, 2011	$ —	$ 8,598	$ 16,587	$ 808

The table below discloses the summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2010 (dollars in thousands):

	Common/collective trusts		Partnership/closely held investments	
	Absolute return	Real estate	Absolute return	Private equity funds
Balance, as of January 1, 2010	$ 844	$ 6,029	$ 15,794	$ 1,561
Realized gains (losses)	(233)	630	—	(148)
Unrealized gains (losses)	(193)	(160)	1,123	(48)
Purchases (sales), net	(323)	(6,076)	—	(93)
Balance, as of December 31, 2010	$ 95	$ 423	$ 16,917	$ 1,272

The market-related value of other postretirement plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). The target asset allocation was 62 percent equity securities and 38 percent debt securities in 2011 and 2010.

The market-related value of other postretirement plan assets was determined as of December 31, 2011 and 2010.

The following table discloses by level within the fair value hierarchy (refer to Note 17 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2011 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 86	$ —	$ 86
Mutual funds:				
Fixed income securities	8,683	—	—	8,683
U.S. equity securities	7,278	—	—	7,278
International equity securities	4,766	—	—	4,766
U.S. equity securities	1,569	—	—	1,569
Other	73	—	—	73
Total	$ 22,369	$ 86	$ —	$ 22,455

The following table discloses by level within the fair value hierarchy (refer to Note 17 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2010 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 118	$ —	$ —	$ 118
Mutual funds:				
Fixed income securities	8,320	—	—	8,320
U.S. equity securities	6,986	—	—	6,986
International equity securities	5,572	—	—	5,572
U.S. equity securities	1,785	—	—	1,785
Other	94	—	—	94
Total	$ 22,875	$ —	$ —	$ 22,875

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase the accumulated postretirement benefit obligation as of December 31, 2011 by $14.8 million and the service and interest cost by $0.8 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease the accumulated postretirement benefit obligation as of December 31, 2011 by $12.3 million and the service and interest cost by $0.7 million.

The Company and its most significant subsidiaries have salary deferral 401(k) plans that are defined contribution plans and cover substantially all employees. Employees can make contributions to their respective accounts in the plans on a pre-tax basis up to the maximum amount permitted by law. The respective company matches a portion of the salary deferred by each participant according to the schedule in the respective plan.

Employer matching contributions were as follows for the years ended December 31 (dollars in thousands):

	2011	2010	2009
Employer 401(k) matching contributions	$ 7,027	$ 5,405	$ 4,667

The Company has an Executive Deferral Plan. This plan allows executive officers and other key employees the opportunity to defer until the earlier of their retirement, termination, disability or death, up to 75 percent of their base salary and/or up to 100 percent of their incentive payments. Deferred compensation funds are held by the Company in a Rabbi Trust.

There were deferred compensation assets included in other intangibles, property and investments — net and corresponding deferred compensation liabilities included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets of the following amounts as of December 31 (dollars in thousands):

	2011	2010
Deferred compensation assets and liabilities	$ 8,653	$ 9,285

NOTE 11. ACCOUNTING FOR INCOME TAXES

Income tax expense consisted of the following for the years ended December 31 (dollars in thousands):

	2011	2010	2009
Taxes currently provided	$ 32,625	$ 13,423	$ 32,470
Deferred income tax expense	24,007	37,734	13,853
Total income tax expense	$ 56,632	$ 51,157	$ 46,323

A reconciliation of federal income taxes derived from statutory federal tax rates (35 percent in 2011, 2010 and 2009) applied to income before income taxes as set forth in the accompanying Consolidated Statements of Income is as follows for the years ended December 31 (dollars in thousands):

	2011	2010	2009
Federal income taxes at statutory rates	$ 56,060	$ 51,137	$ 47,182
Increase (decrease) in tax resulting from:			
Tax effect of regulatory treatment of utility plant differences	1,798	2,761	1,858
State income tax expense	687	624	2,746
Settlement of prior year tax returns and adjustment of tax reserves	163	(1,030)	(2,726)
Manufacturing deduction	(1,099)	(1,630)	(1,091)
Kettle Falls tax credit	—	—	(1,622)
Other	(977)	(705)	(24)
Total income tax expense	$ 56,632	$ 51,157	$ 46,323

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and tax credit carryforwards.

The total net deferred income tax liability consisted of the following as of December 31 (dollars in thousands):

	2011	2010
Deferred income tax assets:		
Allowance for doubtful accounts	$ 12,086	$ 12,556
Reserves not currently deductible	6,302	5,872
Net operating loss from subsidiary acquisition	14,867	6,495
Deferred compensation	3,248	3,877
Unfunded benefit obligation	80,939	54,195
Utility energy commodity derivatives	38,999	28,878
Power and natural gas deferrals	9,545	7,726
Tax credits	16,924	14,671
Other	18,838	23,226
Total deferred income tax assets	201,748	157,496
Deferred income tax liabilities:		
Intangible assets from subsidiary acquisition	8,334	3,505
Differences between book and tax basis of utility plant	478,604	457,661
Power deferrals	—	8,747
Regulatory asset for pensions and other postretirement benefits	91,125	62,645
Power exchange contract	15,571	19,966
Utility energy commodity derivatives	38,992	28,880
Loss on reacquired debt	7,193	7,979
Interest rate swaps	3,720	333
Settlement with Coeur d'Alene Tribe	19,185	21,193
Other	14,505	13,239
Total deferred income tax liabilities	677,229	624,148
Net deferred income tax liability	$ 475,481	$ 466,652
Current deferred income tax asset	$ 30,473	$ 28,822
Long-term deferred income tax liability	505,954	495,474
Net deferred income tax liability	$ 475,481	$ 466,652

As of December 31, 2011, the Company had $12.4 million of state tax credit carryforwards. State tax credits expire from 2015 to 2025. The Company recognizes the effect of state tax credits generated from utility plant as they are utilized.

The realization of deferred income tax assets is dependent upon the ability to generate taxable income in future periods. The Company evaluated available evidence supporting the realization of its deferred income tax assets and determined it is more likely than not that deferred income tax assets will be realized.

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon and Montana. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The Internal Revenue Service (IRS) has completed its examination of all tax years through 2007 and all issues were resolved related to these years. The IRS has not completed an examination of the Company's 2008, 2009 or 2010 federal income tax returns. The Company does not believe that any open tax years for federal or state income taxes could result in any adjustments that would be significant to the consolidated financial statements.

The Company did not incur any penalties on income tax positions in 2011, 2010 or 2009. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operating expense.

The Company had net regulatory assets related to the probable recovery of certain deferred income tax liabilities from customers through future rates as of December 31 (dollars in thousands):

	2011	2010
Regulatory assets for deferred income taxes	$ 84,576	$ 90,025

NOTE 12. ENERGY PURCHASE CONTRACTS

Avista Utilities has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The termination dates of the contracts range from one month to the year 2055.

Total expenses for power purchased, natural gas purchased, fuel for generation and other fuel costs, which are included in utility resource costs in the Consolidated Statements of Income, were as follows for the years ended December 31 (dollars in thousands):

	2011	2010	2009
Utility power resources	$ 557,619	$ 649,408	$ 704,886

The following table details Avista Utilities' future contractual commitments for power resources (including transmission contracts) and natural gas resources (including transportation contracts) (dollars in thousands):

	2012	2013	2014	2015	2016	Thereafter	Total
Power resources	$ 218,599	$ 157,401	$ 139,180	$ 116,184	$ 111,698	$ 1,037,268	$ 1,780,330
Natural gas resources	134,047	102,923	87,926	72,632	54,475	639,790	1,091,793
Total	$ 352,646	$ 260,324	$ 227,106	$ 188,816	$ 166,173	$ 1,677,058	$ 2,872,123

These energy purchase contracts were entered into as part of Avista Utilities' obligation to serve its retail electric and natural gas customers' energy requirements. As a result, these costs are recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost deferral and recovery mechanisms.

In addition, Avista Utilities has operational agreements, settlements and other contractual obligations for its generation, transmission and distribution facilities. The expenses associated with these agreements are reflected as other operating expenses in the Consolidated Statements of Income.

The following table details future contractual commitments for these agreements (dollars in thousands):

	2012	2013	2014	2015	2016	Thereafter	Total
Contractual obligations	$ 29,103	$ 30,346	$ 30,891	$ 28,392	$ 32,528	$ 246,503	$ 397,763

Avista Utilities has fixed contracts with certain Public Utility Districts (PUD) to purchase portions of the output of certain generating facilities. Although Avista Utilities has no investment in the PUD generating facilities, the fixed contracts obligate Avista Utilities to pay certain minimum amounts (based in part on the debt service requirements of the PUD) whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in utility resource costs in the Consolidated Statements of Income.

Expenses under these PUD contracts were as follows for the years ended December 31 (dollars in thousands):

	2011	2010	2009
PUD contract costs	$ 10,533	$ 8,287	$ 12,633

Information as of December 31, 2011 pertaining to these PUD contracts is summarized in the following table (dollars in thousands):

			Company's Current Share of			
	Output	Kilowatt Capability	Annual Costs [1]	Debt Service Costs [1]	Bonds Outstanding	Expiration Date
Chelan County PUD:						
Rocky Reach Project	2.9%	37,000	$ 2,017	$ 887	$ —	2011
Douglas County PUD:						
Wells Project	3.4%	28,000	2,456	876	3,613	2018
Grant County PUD:						
Priest Rapids and Wanapum Projects	3.3%	65,800	6,060	2,203	30,263	2055
Totals		130,800	$ 10,533	$ 3,966	$ 33,876	

(1) The annual costs will change in proportion to the percentage of output allocated to Avista Utilities in a particular year. Amounts represent the operating costs for 2011. Debt service costs are included in annual costs.

The estimated aggregate amounts of required minimum payments (Avista Utilities' share of existing debt service costs) under these PUD contracts are as follows (dollars in thousands):

	2012	2013	2014	2015	2016	Thereafter	Total
Minimum payments	$ 3,337	$ 3,332	$ 3,305	$ 3,195	$ 3,106	$ 44,835	$ 61,110

In addition, Avista Utilities will be required to pay its proportionate share of the variable operating expenses of these projects.

NOTE 13. 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. In December 2011, this committed line of credit was amended to extend the expiration date to February 2017 and revise the pricing terms.

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 December 31, 2011, the Company was in compliance with this covenant.

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

	2011	2010	2009
Balance outstanding at end of period	$ 61,000	$ 110,000	$ 87,000
Letters of credit outstanding at end of period	$ 29,030	$ 27,126	$ 28,448
Average interest rate at end of period	1.12%	0.57%	0.59%

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. In December 2011, the amount of this committed line of credit was increased to $60.0 million. The amount of this committed line of credit will decrease to $55.0 million on September 30, 2012 and $50.0 million on December 31, 2012. The credit agreement is secured by substantially all of Ecova's assets.

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

	2011	2010	2009
Balance outstanding at end of period	$ 35,000	$ —	$ 5,700
Average interest rate at end of period	2.38%	—	1.23%

NOTE 14. LONG-TERM DEBT

The following details long-term debt outstanding as of December 31 (dollars in thousands):

Maturity Year	Description	Interest Rate	2011	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
2041	First Mortgage Bonds (3)	4.45%	85,000	—
	Total secured long-term debt		1,263,700	1,178,700
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Other long-term debt and capital leases		5,455	5,500
	Settled interest rate swaps		(10,629)	(951)
	Unamortized debt discount		(1,626)	(1,792)
	Total		1,261,000	1,185,557
	Secured Pollution Control Bonds held by Avista Corporation (1)(2)		(83,700)	(83,700)
	Current portion of long-term debt		(7,474)	(358)
	Total long-term debt		$ 1,169,826	$ 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 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 Consolidated Balance Sheet.

(3) In December 2011, the Company issued $85.0 million of 4.45 percent First Mortgage Bonds due in 2041.

The following table details future long-term debt maturities including long-term debt to affiliated trusts (see Note 15) (dollars in thousands):

	2012	2013	2014	2015	2016	Thereafter	Total
Debt maturities	$ 7,000	$ 50,000	$ —	$ —	$ —	$ 1,178,647	$ 1,235,647

Substantially all utility properties owned by the Company are subject to the lien of the Company's mortgage indenture. Under the Mortgage and Deed of Trust securing the Company's First Mortgage Bonds (including Secured Medium-Term Notes), the Company may issue additional First Mortgage Bonds in an aggregate principal amount equal to the sum of: 1) 66-2/3 percent of the cost or fair value (whichever is lower) of property additions which have not previously been made the basis of any application under the Mortgage, or 2) an equal principal amount of retired First Mortgage Bonds which have not previously been made the basis of any application under the Mortgage, or 3) deposit of cash. However, the Company may not issue any additional First Mortgage Bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the Company's "net earnings" (as defined in the Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the First Mortgage Bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2011, property additions and retired bonds would have allowed the Company to issue $727.1 million in aggregate principal amount of additional First Mortgage Bonds.

See Note 13 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its committed line of credit agreement.

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.

The following table details future nonrecourse long-term debt maturities (dollars in thousands):

	2012	2013	2014	2015	Total
Debt maturities	$ 13,668	$ 14,965	$ 16,407	$ 1,431	$ 46,471

NOTE 15. LONG-TERM DEBT TO AFFILIATED TRUSTS

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly.

The distribution rates paid were as follows during the years ended December 31:

	2011	2010	2009
Low distribution rate	1.13%	1.13%	1.22%
High distribution rate	1.40	1.41	3.06
Distribution rate at the end of the year	1.40	1.17	1.22

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These debt securities may be redeemed at the option of Avista Capital II on or after June 1, 2007 and mature on June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company owns 100 percent of Avista Capital II and has solely and unconditionally guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent that Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed. The Company does not include these capital trusts in its consolidated financial statements as Avista Corp. is not the primary beneficiary. As such, the sole assets of the capital trusts are $51.5 million of junior subordinated deferrable interest debentures of Avista Corp., which are reflected on the Consolidated Balance Sheets. Interest expense to affiliated trusts in the Consolidated Statements of Income represents interest expense on these debentures.

NOTE 16. LEASES

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from one to forty-five years.

Rental expense under operating leases was as follows for the years ended December 31 (dollars in thousands):

	2011	2010	2009
Rental expense	$ 6,463	$ 6,080	$ 5,624

Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2011 were as follows (dollars in thousands):

	2012	2013	2014	2015	2016	Thereafter	Total
Minimum payments required	$ 5,023	$ 4,885	$ 4,960	$ 2,757	$ 1,070	$ 4,624	$ 23,319

NOTE 17. 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 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 Consolidated Balance Sheets as of December 31 (dollars in thousands):

	2011		2010	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt	$ 1,184,100	$ 1,369,763	$ 1,099,100	$ 1,139,765
Nonrecourse long-term debt	46,471	51,974	58,934	64,795
Long-term debt to affiliated trusts	51,547	43,810	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.

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

	Level 1	Level 2	Level 3	Counterparty Netting [1]	Total
December 31, 2011					
Assets:					
Energy commodity derivatives	$ —	$ 80,571	$ 5,630	$ (84,877)	$ 1,324
Foreign currency derivatives	—	32	—	—	32
Investments and funds held for clients:					
Money market funds [2]	21,957	—	—	—	21,957
Securities available for sale:					
U.S. government agency	—	74,893	—	—	74,893
Municipal	—	425	—	—	425
Corporate fixed income — financial	—	11,154	—	—	11,154
Corporate fixed income — industrial	—	6,518	—	—	6,518
Corporate fixed income — utility	—	2,092	—	—	2,092
Certificate of deposits	—	1,497	—	—	1,497
Funds held in trust account of Spokane Energy	1,600	—	—	—	1,600
Deferred compensation assets:					
Fixed income securities [3]	2,116	—	—	—	2,116
Equity securities [3]	5,252	—	—	—	5,252
Total	$ 30,925	$ 177,182	$ 5,630	$ (84,877)	$ 128,860
Liabilities:					
Energy commodity derivatives	$ —	$ 177,743	$ 18,488	$ (84,877)	$ 111,354
Interest rate swaps	—	18,895	—	—	18,895
Total	$ —	$ 196,638	$ 18,488	$ (84,877)	$ 130,249
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
Funds held for clients [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 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 Consolidated Balance Sheets is due to netting arrangements with certain counterparties. The Company uses quoted market prices and forward price curves to estimate the fair value of utility derivative commodity instruments included in Level 2. In particular, electric derivative valuations are performed using broker quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange (NYMEX) pricing for similar instruments, adjusted for basin differences, using broker quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

For securities available for sale (held at Ecova) the Company uses a nationally recognized third party to obtain fair value and reviews these prices for accuracy using a variety of market tools and analysis. The Company's pricing vendor uses a generic model which uses standard inputs, 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 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 6 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 $1.3 million as of December 31, 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 years ended December 31 (dollars in thousands):

	Assets			Liabilities		
	2011	2010	2009	2011	2010	2009
Balance as of January 1	$ 19,739	$ 57,276	$ 68,047	$ (6,280)	$ (7,806)	$ (16,085)
Total gains or losses (realized/unrealized):						
Included in net income	—	—	—	—	—	—
Included in other comprehensive income	—	—	—	—	—	—
Included in regulatory assets/liabilities (1)	(14,084)	(34,943)	(7,202)	(10,792)	1,209	7,747
Purchases	—	—	—	—	—	—
Issuance	—	—	—	—	—	—
Settlements	(25)	(2,594)	(3,569)	2,988	317	532
Transfers to other categories (2)	—	—	—	(4,404)	—	—
Ending balance as of December 31	$ 5,630	$ 19,739	$ 57,276	$ (18,488)	$ (6,280)	$ (7,806)

(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 Consolidated Statements of Income. Realized gains or losses are recognized in the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases.

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

NOTE 18. COMMON STOCK

The Company has a Direct Stock Purchase and Dividend Reinvestment Plan under which the Company's shareholders may automatically reinvest their dividends and make optional cash payments for the purchase of the Company's common stock at current market value. Shares issued under this plan in 2011, 2010 and 2009 are disclosed in the Consolidated Statements of Equity and Redeemable Noncontrolling Interests.

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock contained in the Company's Articles of Incorporation, as amended.

In August 2010, the Company entered into an amended and restated sales agency agreement with a sales agent to issue up to 3,087,500 shares of its common stock from time to time. The Company originally entered into a sales agency agreement to issue up to 1,250,000 shares of its common stock in December 2009.

Shares issued under sales agency agreements were as follows in the years ended December 31:

	2011	2010	2009
Shares issued under sales agency agreement	807,000	2,054,110	—

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2011 and 2010.

NOTE 19. 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 years ended December 31 (in thousands, except per share amounts):

	2011	2010	2009
Numerator:			
Net income attributable to Avista Corporation	$ 100,224	$ 92,425	$ 87,071
Subsidiary earnings adjustment for dilutive securities	(473)	(226)	(114)
Adjusted net income attributable to Avista Corporation for computation of diluted earnings per common share	$ 99,751	$ 92,199	$ 86,957
Denominator:			
Weighted-average number of common shares outstanding — basic	57,872	55,595	54,694
Effect of dilutive securities:			
Performance and restricted stock awards	172	157	163
Stock options	48	72	85
Weighted-average number of common shares outstanding — diluted	58,092	55,824	54,942
Potential shares excluded in calculation (1)	—	—	218
Earnings per common share attributable to Avista Corporation:			
Basic	$ 1.73	$ 1.66	$ 1.59
Diluted	$ 1.72	$ 1.65	$ 1.58

(1) Certain stock options were excluded from the calculation because they were antidilutive based on the fact that the exercise price of the stock options was higher than the average market price of Avista Corp. common stock during the respective period.

NOTE 20. STOCK COMPENSATION PLANS

1998 Plan

In 1998, the Company adopted, and shareholders approved, the Long-Term Incentive Plan (1998 Plan). Under the 1998 Plan, certain key employees, officers and non-employee directors of the Company and its subsidiaries may be granted stock options, stock appreciation rights, stock awards (including restricted stock) and other stock-based awards and dividend equivalent rights. The Company has available a maximum of 4.5 million shares of its common stock for grant under the 1998 Plan. As of December 31, 2011, 0.2 million shares were remaining for grant under this plan.

2000 Plan

In 2000, the Company adopted a Non-Officer Employee Long-Term Incentive Plan (2000 Plan), which was not required to be approved by shareholders. The provisions of the 2000 Plan are essentially the same as those under the 1998 Plan, except for the exclusion of non-employee directors and executive officers of the Company. The Company has available a maximum of 2.5 million shares of its common stock for grant under the 2000 Plan. However, the Company currently does not plan to issue any further options or securities under the 2000 Plan. As of December 31, 2011, 1.8 million shares were remaining for grant under this plan.

Stock Compensation

The Company records compensation cost relating to share-based payment transactions in the financial statements based on the fair value of the equity or liability instruments issued.

The Company recorded stock-based compensation expense (included in other operating expenses) and income tax benefits in the Consolidated Statements of Income of the following amounts for the years ended December 31 (dollars in thousands):

	2011	2010	2009
Stock-based compensation expense	$ 5,756	$ 4,916	$ 2,906
Income tax benefits	2,014	1,720	1,017

Stock Options

The following summarizes stock options activity under the 1998 Plan and the 2000 Plan for the years ended December 31:

	2011	2010	2009
Number of shares under stock options:			
Options outstanding at beginning of year	201,674	523,973	748,673
Options granted	—	—	—
Options exercised	(107,575)	(101,649)	(200,225)
Options canceled	(1,600)	(220,650)	(24,475)
Options outstanding and exercisable at end of year	92,499	201,674	523,973
Weighted average exercise price:			
Options exercised	$ 12.25	$ 11.51	$ 13.83
Options canceled	$ 11.80	$ 22.60	$ 22.69
Options outstanding and exercisable at end of year	$ 10.69	$ 11.53	$ 16.30
Cash received from options exercised (in thousands)	$ 1,318	$ 2,179	$ 2,770
Intrinsic value of options exercised (in thousands)	$ 1,279	$ 1,006	$ 1,180
Intrinsic value of options outstanding (in thousands)	$ 1,393	$ 2,217	$ 2,774

Information for options outstanding and exercisable as of December 31, 2011 is as follows:

Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$10.17	80,499	$ 10.17	0.85
$12.41	6,000	12.41	1.35
$15.88	6,000	15.88	0.36
Total	92,499	$ 10.69	0.85

As of December 31, 2011 and 2010, the Company's stock options were fully vested and expensed.

Restricted Shares

Restricted shares vest in equal thirds each year over a three-year period and are payable in Avista Corp. common stock at the end of each year if the service condition is met. In addition to the service condition, the Company must meet a return on equity target in order for the CEO's restricted shares to vest. During the vesting period, employees are entitled to dividend equivalents which are paid when dividends on the Company's common stock are declared. Restricted stock is valued at the close of market of the Company's common stock on the grant date. The weighted average remaining vesting period for the Company's restricted shares outstanding as of December 31, 2011 was 0.7 years.

The following table summarizes restricted stock activity for the years ended December 31:

	2011	2010	2009
Unvested shares at beginning of year	84,134	71,904	55,939
Shares granted	50,618	43,800	44,400
Shares canceled	(431)	—	(10,000)
Shares vested	(40,839)	(31,570)	(18,435)
Unvested shares at end of year	93,482	84,134	71,904
Weighted average fair value at grant date	$ 23.06	$ 19.80	$ 18.18
Unrecognized compensation expense at end of year (in thousands)	$ 932	$ 735	$ 668
Intrinsic value, unvested shares at end of year (in thousands)	$ 2,407	$ 1,895	$ 1,552
Intrinsic value, shares vested during the year (in thousands)	$ 934	$ 682	$ 345

Performance Shares

Performance share grants have vesting periods of three years. Performance awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific performance conditions. Based on the attainment of the performance condition, the amount of cash paid or common stock issued will range from 0 to 150 percent of the performance shares granted for grants prior to 2011 and 0 to 200 percent for 2011 grants depending on the change in the value of the Company's common stock relative to an external benchmark. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest.

Performance share awards entitle the grantee to shares of common stock or cash payable once the service condition is satisfied. Based on attainment of the performance condition, grantees may receive 0 to 150 percent of the original shares granted for grants prior to 2011 and 0 to 200 percent for shares granted in 2011. The performance condition used is the Company's Total Shareholder Return performance over a three-year period as compared against other utilities; this is considered a market-based condition. Performance shares may be settled in common stock or cash at the discretion of the Company. Historically, the Company has settled these awards through issuance of stock and intends to continue this practice. These awards vest at the end of the three-year period. Performance shares are equity awards with a market-based condition, which results in the compensation cost for these awards being recognized over the requisite service period, provided that the requisite service period is rendered, regardless of when, if ever, the market condition is satisfied.

The Company measures (at the grant date) the estimated fair value of performance shares granted. The fair value of each performance share award was estimated on the date of grant using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to a peer group. Expected volatility was based on the historical volatility of Avista Corp. common stock over a three-year period. The expected term of the performance shares is three years based on the performance cycle. The risk-free interest rate was based on the U.S. Treasury yield at the time of grant. The compensation expense on these awards will only be adjusted for changes in forfeitures.

The following summarizes the weighted average assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2011	2010	2009
Risk-free interest rate	1.2%	1.4%	1.3%
Expected life, in years	3	3	3
Expected volatility	26.9%	27.8%	25.8%
Dividend yield	4.7%	4.6%	3.6%
Weighted average grant date fair value (per share)	$ 20.79	$ 15.30	$ 17.22

The fair value includes both performance shares and dividend equivalent rights.

The following summarizes performance share activity:

	2011	2010	2009
Opening balance of unvested performance shares	325,700	300,601	252,923
Performance shares granted	184,600	168,700	163,900
Performance shares canceled	(2,177)	—	(43,758)
Performance shares vested	(156,778)	(143,601)	(72,464)
Ending balance of unvested performance shares	351,345	325,700	300,601
Intrinsic value of unvested performance shares (in thousands)	$ 9,047	$ 7,335	$ 6,490
Unrecognized compensation expense (in thousands)	$ 2,991	$ 2,330	$ 2,453

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2011 was 1.5 years. Unrecognized compensation expense as of December 31, 2011 will be recognized during 2012 and 2013.

The following summarizes the impact of the market condition on the vested performance shares:

	2011	2010	2009
Performance shares vested	156,778	143,601	72,464
Impact of market condition on shares vested	(15,678)	21,540	(72,464)
Shares of common stock earned	141,100	165,141	—
Intrinsic value of common stock earned (in thousands)	$ 3,633	$ 3,719	$ —

Shares earned under this plan are distributed to participants in the quarter following vesting.

Awards outstanding under the performance share grants include a dividend component that is paid in cash. This component of the performance share grants is accounted for as a liability award. These liability awards are revalued on a quarterly basis taking into account the number of awards outstanding, historical dividend rate, and the change in the value of the Company's common stock relative to an external benchmark. Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2011 and 2010, the Company had recognized compensation expense and a liability of $1.0 million and $0.9 million related to the dividend component of performance share grants.

Ecova

Ecova has an employee stock incentive plan under which certain employees of Ecova may be granted options to purchase shares of Ecova at prices no less than the estimated fair value on the date of grant. Options outstanding under this plan generally vest over periods of four years from the date granted and terminate ten years from the date granted. Unrecognized compensation expense for stock based awards at Ecova was $2.9 million as of December 31, 2011, which will be expensed during 2012 through 2015.

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. In 2009, Ecova amended its employee stock incentive plan to make this put feature optional for future stock option grants. Stock is reacquired at fair market value at the date of reacquisition. Additionally, there were redeemable noncontrolling interests related to the Cadence Network acquisition, as the previous owners can exercise a right to put their stock back to Ecova (refer to Note 5 for further information).

The following amounts of common stock were repurchased from Ecova employees during the years ended December 31 (dollars in thousands):

	2011	2010	2009
Stock repurchased from Ecova employees	$ 464	$ 2,593	$ 4,725

NOTE 21. 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.

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

California Refund Proceeding

In July 2001, the FERC ordered an evidentiary hearing to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the CalISO and the CalPX during the period from October 2, 2000 to June 20, 2001 (Refund Period). Proposed refunds are based on the calculation of mitigated market clearing prices for each hour. The FERC ruled that if the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, sellers may document these costs and limit their refund liability commensurately. In September 2005, Avista Energy submitted its cost filing claim pursuant to the FERC's August 2005 order. The filing was initially accepted by the FERC, but in March 2011, the FERC ordered Avista Energy to remove any return on equity in a compliance filing with the CalISO, which Avista Energy did in April 2011. A challenge to Avista Energy's cost filing by the California AG, the CPUC, PG&E and SCE was denied in July 2011 as a collateral attack on the FERC's prior orders accepting Avista Energy's cost filing. In July 2011, the California AG, the CPUC, PG&E and SCE filed a petition for review of the FERC's orders regarding Avista Energy's cost filing with the Ninth Circuit.

The 2001 bankruptcy of PG&E resulted in a default on its payment obligations to the CalPX. As a result, Avista Energy has not been paid for all of its energy sales during the Refund Period. Those funds are now in escrow accounts and will not be released until the FERC issues an order directing such release in the California refund proceeding. The CalISO continues to work on its compliance filing for the Refund Period, which will show "who owes what to whom." In July 2011, the FERC accepted the preparatory rerun compliance filings by the CalPX and CalISO, and responded to the CalPX request for guidance on issues related to completing the final determination of "who owes what to whom." The FERC directed both the CalISO and the CalPX to prepare and submit to the FERC their final refund rerun compliance filings. The FERC's order also directs the CalPX to pay past due principal amounts to governmental entities. In February 2012, the FERC denied the challenges made to the July 2011 order by the California AG, the CPUC, PG&E and SCE. As of December 31, 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 April 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 with 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 would result in a material loss. This is primarily due to the fact that the FERC orders have stated that any refunds will be netted against unpaid amounts owed to the respective parties and the Company does not believe that refunds would exceed unpaid amounts owed to the Company.

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. In August 2007, the Ninth Circuit found that the FERC, in denying the request for refunds, had failed to take into account new evidence of market manipulation in the California energy market and its potential ties to the Pacific Northwest energy market and that such failure was arbitrary and capricious and, accordingly, remanded the case to the FERC, stating that the FERC's findings must be reevaluated in light of the evidence. In addition, the Ninth Circuit concluded that the FERC abused its discretion in denying potential relief for transactions involving energy that was purchased by the California 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. A procedural schedule in this docket has not yet been set.

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.

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 effect on its financial condition, results of operations or cash flows.

Colstrip Generating Project Complaint

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

Harbor Oil Inc. Site

Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, the Environmental Protection Agency (EPA) Region 10 provided notification to Avista Corp. and several other parties, as customers of Harbor Oil, that the EPA had determined that hazardous substances were released at the Harbor Oil site in Portland, Oregon and that Avista Corp. and several other parties may be liable for investigation and cleanup of the site under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as the federal “Superfund” law, which provides for joint and several liability. The initial indication from the EPA is that the site may be contaminated with PCBs, petroleum hydrocarbons, chlorinated solvents and heavy metals. Six potentially responsible parties, including Avista Corp., signed an Administrative Order on Consent with the EPA on May 31, 2007 to conduct a remedial investigation and feasibility study (RI/FS). The draft final RI/FS was submitted to the EPA in December 2011. The actual cleanup, if any, will not occur until the RI/FS is finalized and approved by the EPA. Based on the review of its records related to Harbor Oil, the Company does not believe it is a major contributor to this potential environmental contamination based on the small volume of waste oil it delivered to the Harbor Oil site. As such, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows. The Company has expensed its share of the RI/FS ($0.5 million) for this matter.

Spokane River Licensing

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

As part of the Settlement Agreement with the Washington Department of Ecology (DOE), the Company has participated in the Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On May 20, 2010, the EPA approved the TMDL and on May 27, 2010, the DOE filed an amended 401 Water Quality Certification with the FERC for inclusion into the license. The amended 401 Water Quality Certification includes the Company’s level of responsibility, as defined in the TMDL, for low dissolved oxygen levels in Lake Spokane. The Company 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. The EPA and the Idaho Department of Environmental Quality (Idaho DEQ) are preparing draft National Pollutant Discharge Elimination System permits and the 401 Water Quality Certifications for the Idaho dischargers, respectively, which once issued will be released for a 30-day public comment period.

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

Cabinet Gorge Total Dissolved Gas Abatement Plan

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

Fish Passage at Cabinet Gorge and Noxon Rapids

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

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

Aluminum Recycling Site

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

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 alleged 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 alleged 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 January 2012, Avista Corp. and its insurance provider reached a settlement with the plaintiffs. Avista Corp. has expensed its share of the settlement (including legal fees) of $2 million (which was recorded in 2010 and 2011).

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. The Company has expensed its estimated liability for this matter, which was not material to its financial condition, results of operations or cash flows. Based on information currently known to the Company's management, the Company does not expect this complaint will have a material effect on its financial condition, results of operations or cash flows.

Collective Bargaining Agreements

The Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represents approximately 45 percent of all of Avista Utilities' employees. The agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the bargaining unit employees expires in March 2014. Two local agreements in Oregon, which cover approximately 50 employees, expired in April 2010. New agreements were reached in December 2010 (expiring in March 2014).

Other Contingencies

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

The Company routinely assesses, based on studies, expert analyses and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who either have or have not agreed to a settlement as well as recoveries from insurance carriers. The Company's policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred. For matters that affect Avista Utilities' operations, the Company seeks, to the extent appropriate, recovery of incurred costs through the ratemaking process.

The Company has potential liabilities under the Endangered Species Act for species of fish that have either already been added to the endangered species list, listed as "threatened" or petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company. However, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. The state of Montana is examining the status of all water right claims within state boundaries. Claims within the Clark Fork River basin could adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho has initiated an adjudication in northern Idaho, which will ultimately include the lower Clark Fork River, the Spokane River and the Coeur d'Alene basin. In addition, the state of Washington has indicated its intent to initiate an adjudication for the Spokane River basin in the next several years. The Company is and will continue to be a participant in these adjudication processes. The complexity of such adjudications makes each unlikely to be concluded in the foreseeable future. As such, it is not possible for the Company to estimate the impact of any outcome at this time.

NOTE 22. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2017. The largest of these contracts provides for increases due to changes in the cost of living index and further provides flexibility in the annual obligation from year-to-year subject to a three-year true-up cycle.

Total payments under these contracts were as follows for the years ended December 31 (dollars in thousands):

	2011	2010	2009
Information service contract payments	$ 13,038	$ 13,426	$ 15,529

The majority of the costs are included in other operating expenses in the Consolidated Statements of Income. Minimum contractual obligations under the Company's information services contracts are $13.0 million in 2012, $10.5 million in 2013, $8.0 million in 2014, and $7.0 million in each of 2015, 2016 and 2017.

Regulatory Assets and Liabilities

The following table presents the Company's regulatory assets and liabilities as of December 31, 2011 (dollars in thousands):

	Remaining Amortization Period	Receiving Regulatory Treatment: Earning A Return (1)	Receiving Regulatory Treatment: Not Earning A Return	Pending Regulatory Treatment (2)	Total 2011	Total 2010
Regulatory Assets:						
Investment in exchange power — net	2019	$ 18,783	$ —	$ —	$ 18,783	$ 21,233
Regulatory assets for deferred income tax	(3)	—	84,576	—	84,576	90,025
Regulatory assets for pensions and other postretirement benefit plans	(4)	—	—	260,359	260,359	178,985
Current regulatory asset for utility derivatives	(5)	—	69,685	—	69,685	48,891
Power deferrals	(3)	—	—	—	—	18,305
Unamortized debt repurchase costs	(6)	23,037	—	—	23,037	25,454
Regulatory asset for settlement with Coeur d'Alene Tribe	2059	52,463	—	—	52,463	54,056
Demand side management programs	(3)	—	798	—	798	4,251
Montana lease payments	(3)	5,096	—	—	5,096	6,134
Lancaster Plant 2010 net costs	2015	5,327	—	—	5,327	6,687
Regulatory asset for interest rate swaps	2012–2013	—	18,895	—	18,895	—
Non-current regulatory asset for utility derivatives	(5)	—	40,345	—	40,345	15,724
Other regulatory assets	(3)	5,097	3,875	5,341	14,313	16,248
Total regulatory assets		$ 109,803	$ 218,174	$ 265,700	$ 593,677	$ 485,993
Regulatory Liabilities:						
Oregon Senate Bill 408	2012	$ 772	$ —	$ —	$ 772	$ 2,545
Natural gas deferrals	(3)	12,140	—	—	12,140	22,074
Power deferrals	(3)	13,692	—	—	13,692	—
Regulatory liability for utility plant retirement costs	(7)	227,282	—	—	227,282	223,131
Income tax related liabilities	(3)	—	18,607	—	18,607	28,353
Regulatory liability for Spokane Energy	(8)	—	—	19,902	19,902	17,076
Other regulatory liabilities	(3)	3,001	2,533	—	5,534	5,043
Total regulatory liabilities		$ 256,887	$ 21,140	$ 19,902	$ 297,929	$ 298,222

(1) Earning a return includes either interest on the regulatory asset/liability, or a return on the investment as a component of rate base or the weighted cost of capital.

(2) Pending regulatory treatment includes regulatory assets and liabilities that have prior regulatory precedent.

(3) Remaining amortization period varies depending on timing of underlying transactions.

(4) As the Company has historically recovered and currently recovers its pension and other postretirement benefit costs related to its regulated operations in retail rates, the Company records a regulatory asset for that portion of its pension and other postretirement benefit funding deficiency.

(5) 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 Consolidated Statements of Income. Realized gains or losses are recognized in the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases.

(6) For the Company's Washington jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums paid to repurchase debt are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. In the Company's other regulatory jurisdictions, premiums paid to repurchase debt prior to 2007 are being amortized over the average remaining maturity of outstanding debt when no new debt was issued in connection with the debt repurchase. These costs are recovered through retail rates as a component of interest expense.

(7) This amount is dependent upon the cost of removal of underlying utility plant assets and the life of utility plant.

(8) Consists of a regulatory liability recorded for the cumulative retained earnings of Spokane Energy that the Company will flow through regulatory accounting mechanisms in future periods.

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge on the Consolidated Balance Sheets for future review and recovery through retail rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Avista Utilities and the costs included in base retail rates. This difference in net power supply costs 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.

In Washington, the Energy Recovery Mechanism (ERM) allows Avista Utilities to periodically increase or decrease electric rates with WUTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual net power supply costs, net of the margin on wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers. In the 2010 Washington general rate case settlement, the parties agreed that there would be no deferrals under the ERM for 2010. Deferrals under the ERM resumed in 2011. Total net deferred power costs under the ERM were a liability of $12.9 million as of December 31, 2011.

The initial amount of power supply costs in excess or below the level in retail rates, which the Company either incurs the cost of, or receives the benefit from, is referred to as the deadband. The annual (calendar year) deadband amount is currently $4.0 million. The Company will incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. The Company shares annual power supply cost variances between $4.0 million and $10.0 million with its 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. The Company absorbs or receives the benefit in power supply costs of the remaining 10 percent of the annual variance beyond $10.0 million without affecting current or future customer rates.

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%

Avista Utilities has a Power Costs Adjustment (PCA) mechanism in Idaho that allows it to modify electric rates on October 1 of each year with Idaho Public Utilities Commission (IPUC) approval. Under the PCA mechanism, Avista Utilities defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers. These annual October 1 rate adjustments recover or rebate power costs deferred during the preceding July–June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a regulatory liability of $0.7 million as of December 31, 2011 and a regulatory asset of $18.3 million as of December 31, 2010.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Utilities files a purchased gas cost adjustment (PGA) in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. These annual PGA filings in Washington and Idaho provide for the deferral, and recovery or refund, of 100 percent of the difference between actual and estimated commodity and pipeline transportation costs, subject to applicable regulatory review. The annual PGA filing in Oregon provides for deferral, and recovery or refund, of 100 percent of the difference between actual and estimated pipeline transportation costs and commodity costs that are fixed through hedge transactions. Commodity costs that are not hedged for Oregon customers are subject to a sharing mechanism whereby Avista Utilities defers, and recovers or refunds, 90 percent of the difference between these actual and estimated costs. Total net deferred natural gas costs to be refunded to customers were a liability of $12.1 million as of December 31, 2011 and $22.1 million as of December 31, 2010.

Washington General Rate Cases

In December 2009, the WUTC issued an order on Avista Corp.'s electric and natural gas general rate cases that were filed with the WUTC in January 2009. The WUTC approved a base electric rate increase for the Company's Washington customers of 2.8 percent, which was designed to increase annual revenues by $12.1 million. Base natural gas rates for the Company's Washington customers increased by an average of 0.3 percent, which was designed to increase annual revenues by $0.6 million. The new electric and natural gas rates became effective on January 1, 2010. In this general rate case order, the WUTC did not allow the Company to include the costs associated with the power purchase agreement for the Lancaster Plant in rates. The Company subsequently filed for and received approval for deferred accounting treatment for these net costs.

In November 2010, the WUTC approved an all-party settlement stipulation in the Company's general rate case filed in March 2010. As agreed to in the settlement stipulation, electric rates for the Company's 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 the Company's 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.

In December 2011, the WUTC approved a settlement agreement in the Company's electric and natural gas general rate cases filed in May 2011. As agreed to in the settlement agreement, base electric rates for the Company's Washington customers increased by an average of 4.6 percent, which is designed to increase annual revenues by $20.0 million. Base natural gas rates for the Company's Washington customers increased 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 became effective on January 1, 2012.

As part of the settlement agreement, the Company 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, the Company is deferring changes in maintenance costs related to its Coyote Spring 2 natural gas-fired generation plant and its 15 percent ownership interest in Units 3&4 of the Colstrip generation plant. The Company compares 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 defers the difference. The deferral will 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 will 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. For 2011, the Company deferred $0.5 million of maintenance costs in Washington.

Idaho General Rate Cases

In July 2009, the IPUC approved a settlement agreement in the Company's general rate cases that were filed with the IPUC in January 2009. The new electric and natural gas rates became effective on August 1, 2009. As agreed to in the settlement, base electric rates for the Company's Idaho customers increased by an average of 5.7 percent, which was designed to increase annual revenues by $12.5 million. Base natural gas rates for the Company's Idaho customers increased by an average of 2.1 percent, which was designed to increase annual revenues by $1.9 million.

In September 2010, the IPUC approved a settlement agreement in the Company's 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 the Company's 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 the Company's Idaho customers increased by an average of 2.6 percent, which was designed to increase annual revenues by $1.8 million.

The 2010 settlement agreement includes a rate mitigation plan under which the impact on customers of the new rates will be 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 the Company's cash collections from customers will be reduced by this amortization during the two-year period, the mitigation plan will have no impact on the Company's net income. Retail rates increased on October 1, 2011 and will increase on October 1, 2012 as the deferred state income tax balance is amortized.

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

As part of the settlement agreement, the Company 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 the Company from filing annual rate adjustments such as the PCA and the PGA.

The settlement agreement also provides for the deferral of certain generation plant operation and maintenance costs. In order to address the variability in year-to-year operation and maintenance costs, beginning in 2011, the Company is deferring changes in operation and maintenance costs related to the Coyote Spring 2 natural gas-fired generation plant and its 15 percent ownership interest in Units 3&4 of the Colstrip generation plant. The Company compares 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 defers 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. For 2011, the Company deferred $0.1 million of operation and maintenance costs in Idaho.

Oregon General Rate Cases

In October 2009, the OPUC approved a settlement agreement in the Company's general rate case that was filed with the OPUC in June 2009. The new natural gas rates became effective on November 1, 2009. As agreed to in the settlement, base natural gas rates for Oregon customers increased by an average of 7.1 percent, which was designed to increase annual revenues by $8.8 million.

In March 2011, the OPUC approved an all-party settlement stipulation in the Company's general rate case that was filed in September 2010. The settlement provides for an overall rate increase of 3.1 percent for the Company's 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.

NOTE 24. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. Avista Utilities' business is managed based on the total regulated utility operation. Ecova is a provider of facility information and cost management services for multi-site customers throughout North America. The Other category, which is not a reportable segment, includes Spokane Energy, other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital.

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 year ended December 31, 2011:						
Operating revenues	$ 1,443,322	$ 137,848	$ 40,410	$ 178,258	$ (1,800)	$ 1,619,780
Resource costs	790,048	—	—	—	—	790,048
Other operating expenses	255,326	109,738	33,897	143,635	(1,800)	397,161
Depreciation and amortization	105,629	7,193	778	7,971	—	113,600
Income from operations	208,970	20,917	5,735	26,652	—	235,622
Interest expense (2)	69,347	305	4,943	5,248	(387)	74,208
Income taxes	48,964	7,852	(184)	7,668	—	56,632
Net income (loss) attributable to Avista Corporation	90,902	9,671	(349)	9,322	—	100,224
Capital expenditures	239,782	2,998	592	3,590	—	243,372
For the year ended December 31, 2010:						
Operating revenues	$ 1,419,646	$ 102,035	$ 61,067	$ 163,102	$ (24,008)	$ 1,558,740
Resource costs	795,075	—	—	—	—	795,075
Other operating expenses	242,521	80,100	53,846	133,946	(24,008)	352,459
Depreciation and amortization	100,554	6,070	1,002	7,072	—	107,626
Income from operations	208,104	15,865	6,219	22,084	—	230,188
Interest expense (2)	70,867	276	5,530	5,806	(249)	76,424
Income taxes	46,428	5,679	(950)	4,729	—	51,157
Net income (loss) attributable to Avista Corporation	86,681	7,433	(1,689)	5,744	—	92,425
Capital expenditures	202,227	1,932	497	2,429	—	204,656
For the year ended December 31, 2009:						
Operating revenues	$ 1,395,201	$ 77,275	$ 40,089	$ 117,364	$ —	$ 1,512,565
Resource costs	799,539	—	—	—	—	799,539
Other operating expenses	229,907	60,985	45,118	106,103	—	336,010
Depreciation and amortization	93,783	4,687	1,305	5,992	—	99,775
Income (loss) from operations	195,389	11,603	(6,334)	5,269	—	200,658
Interest expense (2)	66,688	302	231	533	(187)	67,034
Income taxes	44,480	3,969	(2,126)	1,843	—	46,323
Net income (loss) attributable to Avista Corporation	86,744	5,329	(5,002)	327	—	87,071
Capital expenditures	205,384	3,031	89	3,120	—	208,504
Total Assets:						
As of December 31, 2011	$ 3,809,446	$ 292,940	$ 112,145	$ 405,085	$ —	$ 4,214,531
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.

NOTE 25. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The Company's energy operations are significantly affected by weather conditions. Consequently, there can be large variances in revenues, expenses and net income between quarters based on seasonal factors such as, but not limited to, temperatures and streamflow conditions.

A summary of quarterly operations (in thousands, except per share amounts) for 2011 and 2010 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2011				
Operating revenues	$ 476,586	$ 360,557	$ 343,710	$ 438,927
Operating expenses	391,761	305,033	308,832	378,532
Income from operations	$ 84,825	$ 55,524	$ 34,878	$ 60,395
Net income	$ 42,403	$ 23,528	$ 11,637	$ 25,971
Less: Net income attributable to noncontrolling interests	(485)	(527)	(935)	(1,368)
Net income attributable to Avista Corporation	$ 41,918	$ 23,001	$ 10,702	$ 24,603
Outstanding common stock:				
Weighted average, basic	57,342	57,787	58,057	58,304
Weighted average, diluted	57,414	58,143	58,232	58,583
Earnings per common share attributable to Avista Corporation, diluted	$ 0.73	$ 0.39	$ 0.18	$ 0.42
2010				
Operating revenues	$ 456,415	$ 360,733	$ 367,172	$ 374,420
Operating expenses	388,591	298,984	329,428	311,549
Income from operations	$ 67,824	$ 61,749	$ 37,744	$ 62,871
Net income	$ 29,317	$ 26,047	$ 13,334	$ 26,250
Less: Net income attributable to noncontrolling interests	(507)	(507)	(988)	(521)
Net income attributable to Avista Corporation	$ 28,810	$ 25,540	$ 12,346	$ 25,729
Outstanding common stock:				
Weighted average, basic	54,869	55,031	55,616	56,835
Weighted average, diluted	55,115	55,231	55,801	57,126
Earnings per common share attributable to Avista Corporation, diluted	$ 0.52	$ 0.46	$ 0.22	$ 0.45

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not applicable.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended) to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company's management, including its principal executive and principal financial officers as appropriate to allow timely decisions regarding required disclosure. Under the supervision and with the participation of the Company's management, including the Company's principal executive officer and principal financial officer, the Company evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives. Based upon the Company's evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures are effective at a reasonable assurance level as of December 31, 2011.

Management's Report on Internal Control Over Financial Reporting

The Company's management, together with its consolidated subsidiaries, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). The Company's internal control over financial reporting is a process designed under the supervision of the Company's principal executive officer and principal financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with accounting principles generally accepted in the United States of America.

The Company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's financial statements.

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 conducted an assessment of the effectiveness of the Company's internal control over financial reporting based on the framework established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that the Company's internal control over financial reporting as of December 31, 2011 is effective at a reasonable assurance level.

The Company's independent registered public accounting firm, Deloitte & Touche LLP, has issued an attest report on the Company's internal control over financial reporting as of December 31, 2011.

Changes in Internal Control Over Financial Reporting

There have been no changes in the Company's internal control over financial reporting that occurred during the Company's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Avista Corporation
Spokane, Washington

We have audited the internal control over financial reporting of Avista Corporation and subsidiaries (the "Company") as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2011 of the Company and our report dated February 28, 2012 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 28, 2012

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding the directors of the Registrant and compliance with Section 16(a) of the Exchange Act has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 10, 2012.

Executive Officers of the Registrant

Name	Age	Business Experience
Scott L. Morris	54	Chairman, President and Chief Executive Officer effective January 1, 2008. Director since February 9, 2007; President and Chief Operating Officer May 2006–December 2007; Senior Vice President February 2002–May 2006; Vice President November 2000–February 2002; President — Avista Utilities August 2000–December 2008; General Manager — Avista Utilities for the Oregon and California operations October 1991–August 2000; various other management and staff positions with the Company since 1981.
Mark T. Thies	48	Senior Vice President and Chief Financial Officer (Principal Financial Officer) since September 2008; prior to employment with the Company held the following positions with Black Hills Corporation: Executive Vice President and Chief Financial Officer March 2003 to January 2008; Senior Vice President and Chief Financial Officer March 2000 to March 2003; Controller May 1997 to March 2000.
Marian M. Durkin	58	Senior Vice President, General Counsel and Chief Compliance Officer since November 2005; Senior Vice President and General Counsel August 2005–November 2005; prior to employment with the Company: held several legal positions with United Air Lines, Inc. from 1995 to August 2005, most recently served as Vice President Deputy General Counsel and Assistant Secretary.
Karen S. Feltes	56	Senior Vice President of Human Resources and Corporate Secretary since November 2005; Vice President of Human Resources and Corporate Secretary March 2003–November 2005; Vice President of Human Resources and Corporate Services February 2002–March 2003; various human resources positions with the Company April 1998–February 2002.
Dennis P. Vermillion	50	Senior Vice President since January 2010; Vice President July 2007–December 2009; President — Avista Utilities since January 2009; Vice President of Energy Resources and Optimization — Avista Utilities July 2007–December 2008; President and Chief Operating Officer of Avista Energy February 2001–July 2007; various other management and staff positions with the Company since 1985.
Christy M. Burmeister-Smith	55	Vice President, Controller and Principal Accounting Officer since May 2007. Vice President and Treasurer January 2006–May 2007; Vice President and Controller June 1999 – January 2006; various other management and staff positions with the Company since 1980.
James M. Kensok	53	Vice President and Chief Information Officer since January 2007; Chief Information Officer February 2001–December 2006; various other management and staff positions with the Company since 1996.
Don F. Kopczynski	56	Vice President since May 2004; Vice President of Customer Solutions — Avista Utilities since April 2011; Vice President of Transmission and Distribution Operations — Avista Utilities May 2004–April 2011; various other management and staff positions with the Company and its subsidiaries since 1979.

Executive Officers of the Registrant

Name	Age	Business Experience
David J. Meyer	58	Vice President and Chief Counsel for Regulatory and Governmental Affairs since February 2004; Senior Vice President and General Counsel September 1998–February 2004.
Kelly O. Norwood	53	Vice President since November 2000; Vice President of State and Federal Regulation — Avista Utilities since March 2002; Vice President and General Manager of Energy Resources — Avista Utilities August 2000–March 2002; various other management and staff positions with the Company since 1981.
Richard L. Storro	61	Vice President since January 2009; Vice President Energy Resources — Avista Utilities since January 2009. Various other management and staff positions with the Company since 1973.
Jason R. Thackston	41	Vice President of Energy Delivery since April 2011; Vice President of Finance June 2009 –April 2011; various other management and staff positions with the Company since 1996.
Roger D. Woodworth	55	Vice President since November 1998; Vice President and Chief Strategy Officer since April 2011; Vice President, Sustainable Energy Solutions Avista Utilities February 2007–April 2011; Vice President, Customer Solutions for Avista Utilities March 2003–February 2007; Vice President of Utility Operations of Avista Utilities September 2001–March 2003; Vice President — Corporate Development November 1998–September 2001; various other management and staff positions with the Company since 1979.

All of the Company's executive officers, with the exception of James M. Kensok, Don F. Kopczynski, David J. Meyer, Kelly O. Norwood and Richard L. Storro, were officers or directors of one or more of the Company's subsidiaries in 2011. The Company's executive officers are elected annually by the Board of Directors.

The Company has adopted a Code of Business Conduct and Ethics (Code of Conduct) for directors, officers (including the principal executive officer, principal financial officer and principal accounting officer), and employees. The Code of Conduct is available on the Company's Web site at www.avistacorp.com and will also be provided to any shareholder without charge upon written request to:

Avista Corp.
General Counsel
P.O. Box 3727 MSC-12
Spokane, Washington 99220-3727

Any changes to or waivers for executive officers and directors of the Company's Code of Conduct will be posted on the Company's Web site.

ITEM 11. EXECUTIVE COMPENSATION

Information regarding executive compensation has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 10, 2012.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

(a) Security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities):

Information regarding security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities) has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 10, 2012.

(b) Security ownership of management:

Information regarding security ownership of management has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 10, 2012.

(c) Changes in control:

None.

(d) Securities authorized for issuance under equity compensation plans as of December 31, 2011:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights (1)	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders (2)	70,500	$ 10.85	163,520
Equity compensation plans not approved by security holders (3)	21,999	$ 10.17	1,864,474
Total	92,499	$ 10.69	2,027,994

(1) Excludes unvested restricted shares and performance share awards granted under Avista Corp.'s Long Term Incentive Plan. At December 31, 2011, 93,482 Restricted Share awards were outstanding. Performance share awards may be paid out at zero shares at a minimum achievement level; 351,345 shares at target level; or 618,585 shares at a maximum level. Because there is no exercise price associated with restricted shares or performance share awards, such shares are not included in the weighted-average price calculation.

(2) Includes the Long-Term Incentive Plan approved by shareholders in 1998 and the Non-Employee Director Stock Plan approved by shareholders in 1996. In February 2005, the Board of Directors elected to terminate the Non-Employee Director Stock Plan.

(3) Represents stock options outstanding and stock available for future issuance under the Non-Officer Employee Long-Term Incentive Plan, which was adopted by the Company in 2000. The Company currently does not plan to issue any further options or securities under this plan. Under this plan, employees (excluding directors and executive officers) of the Company and its subsidiaries may be granted stock options, stock appreciation rights, stock awards, performance awards, other stock-based awards and dividend equivalent rights. Stock options granted under this plan are equal to the market price of the Company's common stock on the date of grant. Stock options granted under this plan have terms of up to 10 years and generally vest at a rate of 25 percent per year over a four-year period.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information regarding certain relationships and related transactions has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 10, 2012.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 10, 2012.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements (Included in Part II of this report):

Report of Independent Registered Public Accounting Firm

Consolidated Statements of Income for the Years Ended December 31, 2011, 2010 and 2009

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2011, 2010 and 2009

Consolidated Balance Sheets as of December 31, 2011 and 2010

Consolidated Statements of Cash Flows for the Years Ended December 31, 2011, 2010 and 2009

Consolidated Statements of Equity and Redeemable Noncontrolling Interests for the Years Ended December 31, 2011, 2010 and 2009

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules:

None

(a) 3. Exhibits:

Reference is made to the Exhibit Index commencing on page 104. The Exhibits include the management contracts and compensatory plans or arrangements required to be filed as exhibits to this Form 10-K pursuant to Item 15(b).

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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

February 28, 2012	By /s/ Scott L. Morris
Date	Scott L. Morris Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Scott L. Morris Scott L. Morris Chairman of the Board, President and Chief Executive Officer	Principal Executive Officer	February 28, 2012
/s/ Mark T. Thies Mark T. Thies (Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 28, 2012
/s/ Christy M. Burmeister-Smith Christy M. Burmeister-Smith (Vice President, Controller and Principal Accounting Officer)	Principal Accounting Officer	February 28, 2012
/s/ Erik J. Anderson Erik J. Anderson	Director	February 28, 2012
/s/ Kristianne Blake Kristianne Blake	Director	February 28, 2012
/s/ Donald C. Burke Donald C. Burke	Director	February 28, 2012
/s/ Rick R. Holley Rick R. Holley	Director	February 28, 2012
/s/ John F. Kelly John F. Kelly	Director	February 28, 2012
/s/ Rebecca A. Klein Rebecca A. Klein	Director	February 28, 2012
/s/ Michael L. Noël Michael L. Noël	Director	February 28, 2012
/s/ Marc F. Racicot Marc F. Racicot	Director	February 28, 2012
/s/ Heidi B. Stanley Heidi B. Stanley	Director	February 28, 2012
/s/ R. John Taylor R. John Taylor	Director	February 28, 2012

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
3.1	1-3701 (with June 30, 2011 Form 10-Q)	3(i)	Restated Articles of Incorporation of Avista Corporation, as amended and restated May 23, 2011.
3.2	1-3701 (with Form 8-K dated as of August 12, 2011)	3.2	Bylaws of Avista Corporation, as amended August 12, 2011.
4.1	2-4077	B-3	Mortgage and Deed of Trust, dated as of June 1, 1939.
4.2	2-9812	4(c)	First Supplemental Indenture, dated as of October 1, 1952.
4.3	2-60728	2(b)-2	Second Supplemental Indenture, dated as of May 1, 1953.
4.4	2-13421	4(b)-3	Third Supplemental Indenture, dated as of December 1, 1955.
4.5	2-13421	4(b)-4	Fourth Supplemental Indenture, dated as of March 15, 1967.
4.6	2-60728	2(b)-5	Fifth Supplemental Indenture, dated as of July 1, 1957.
4.7	2-60728	2(b)-6	Sixth Supplemental Indenture, dated as of January 1, 1958.
4.8	2-60728	2(b)-7	Seventh Supplemental Indenture, dated as of August 1, 1958.
4.9	2-60728	2(b)-8	Eighth Supplemental Indenture, dated as of January 1, 1959.
4.10	2-60728	2(b)-9	Ninth Supplemental Indenture, dated as of January 1, 1960.
4.11	2-60728	2(b)-10	Tenth Supplemental Indenture, dated as of April 1, 1964.
4.12	2-60728	2(b)-11	Eleventh Supplemental Indenture, dated as of March 1, 1965.
4.13	2-60728	2(b)-12	Twelfth Supplemental Indenture, dated as of May 1, 1966.
4.14	2-60728	2(b)-13	Thirteenth Supplemental Indenture, dated as of August 1, 1966.
4.15	2-60728	2(b)-14	Fourteenth Supplemental Indenture, dated as of April 1, 1970.
4.16	2-60728	2(b)-15	Fifteenth Supplemental Indenture, dated as of May 1, 1973.
4.17	2-60728	2(b)-16	Sixteenth Supplemental Indenture, dated as of February 1, 1975.
4.18	2-60728	2(b)-17	Seventeenth Supplemental Indenture, dated as of November 1, 1976.
4.19	2-69080	2(b)-18	Eighteenth Supplemental Indenture, dated as of June 1, 1980.
4.20	1-3701 (with 1980 Form 10-K)	4(a)-20	Nineteenth Supplemental Indenture, dated as of January 1, 1981.
4.21	2-79571	4(a)-21	Twentieth Supplemental Indenture, dated as of August 1, 1982.
4.22	1-3701 (with Form 8-K dated September 20, 1983)	4(a)-22	Twenty-First Supplemental Indenture, dated as of September 1, 1983.

	Previously Filed [1]		
Exhibit	With Registration Number	As Exhibit	
4.23	2-94816	4(a)-23	Twenty-Second Supplemental Indenture, dated as of March 1, 1984.
4.24	1-3701 (with 1986 Form 10-K)	4(a)-24	Twenty-Third Supplemental Indenture, dated as of December 1, 1986.
4.25	1-3701 (with 1987 Form 10-K)	4(a)-25	Twenty-Fourth Supplemental Indenture, dated as of January 1, 1988.
4.26	1-3701 (with 1989 Form 10-K)	4(a)-26	Twenty-Fifth Supplemental Indenture, dated as of October 1, 1989.
4.27	33-51669	4(a)-27	Twenty-Sixth Supplemental Indenture, dated as of April 1, 1993.
4.28	1-3701 (with 1993 Form 10-K)	4(a)-28	Twenty-Seventh Supplemental Indenture, dated as of January 1, 1994.
4.29	1-3701 (with 2001 Form 10-K)	4(a)-29	Twenty-Eighth Supplemental Indenture, dated as of September 1, 2001.
4.30	333-82502	4(b)	Twenty-Ninth Supplemental Indenture, dated as of December 1, 2001.
4.31	1-3701 (with June 30, 2002 10-Q)	4(f)	Thirtieth Supplemental Indenture, dated as of May 1, 2002.
4.32	333-39551	4(b)	Thirty-First Supplemental Indenture, dated as of May 1, 2003.
4.33	1-3701 (with September 30, 2003 10-Q)	4(f)	Thirty-Second Supplemental Indenture, dated as of September 1, 2003.
4.34	333-64652	4(a)33	Thirty-Third Supplemental Indenture, dated as of May 1, 2004.
4.35	1-3701 (with Form 8-K dated as of December 15, 2004)	4.1	Thirty-Fourth Supplemental Indenture, dated as of November 1, 2004.
4.36	1-3701 (with Form 8-K dated as of December 15, 2004)	4.2	Thirty-Fifth Supplemental Indenture, dated as of December 1, 2004.
4.37	1-3701 (with Form 8-K dated as of December 15, 2004)	4.3	Thirty-Sixth Supplemental Indenture, dated as of December 1, 2004.
4.38	1-3701 (with Form 8-K dated as of December 15, 2004)	4.4	Thirty-Seventh Supplemental Indenture, dated as of December 1, 2004.
4.39	1-3701 (with Form 8-K dated as of May 12, 2005)	4.1	Thirty-Eighth Supplemental Indenture, dated as of May 1, 2005.

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
4.40	1-3701 (with Form 8-K dated as of November 17, 2005)	4.1	Thirty-Ninth Supplemental Indenture, dated as of November 1, 2005.
4.41	1-3701 (with Form 8-K dated as of April 6, 2006)	4.1	Fortieth Supplemental Indenture, dated as of April 1, 2006.
4.42	1-3701 (with Form 8-K dated as of December 15, 2006)	4.1	Forty-First Supplemental Indenture, dated as of December 1, 2006.
4.43	1-3701 (with Form 8-K dated as of April 3, 2008)	4.1	Forty-Second Supplemental Indenture, dated as of April 1, 2008.
4.44	1-3701 (with Form 8-K dated as of November 26, 2008)	4.1	Forty-Third Supplemental Indenture, dated as of November 1, 2008.
4.45	1-3701 (with Form 8-K dated as of December 16, 2008)	4.1	Forty-Fourth Supplemental Indenture, dated as of December 1, 2008.
4.46	1-3701 (with Form 8-K dated as of December 30, 2008)	4.3	Forty-Fifth Supplemental Indenture, dated as of December 1, 2008.
4.47	1-3701 (with Form 8-K dated as of September 15, 2009)	4.1	Forty-Sixth Supplemental Indenture, dated as of September 1, 2009.
4.48	1-3701 (with Form 8-K dated as of November 25, 2009)	4.1	Forty-Seventh Supplemental Indenture, dated as of November 1, 2009.
4.49	1-3701 (with Form 8-K dated as of December 15, 2010)	4.5	Forty-Eighth Supplemental Indenture, dated as of December 1, 2010.
4.50	1-3701 (with Form 8-K dated as of December 20, 2010)	4.1	Forty-Ninth Supplemental Indenture, dated as of December 1, 2010.
4.51	1-3701 (with Form 8-K dated as of December 30, 2010)	4.1	Fiftieth Supplemental Indenture, dated as of December 1, 2010.
4.52	1-3701 (with Form 8-K dated as of February 11, 2011)	4.1	Fifty-First Supplemental Indenture, dated as of February 1, 2011.

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
4.53	1-3701 (with Form 8-K dated as of August 16, 2011)	4.1	Fifty-Second Supplemental Indenture, dated as of August 1, 2011.
4.54	1-3701 (with Form 8-K dated as of December 14, 2011)	4.1	Fifty-Third Supplemental Indenture, dated as of December 1, 2011.
4.55	1-3701 (with Form 8-K dated as of December 15, 2004)	4.5	Supplemental Indenture No. 1, dated as of December 1, 2004 to the Indenture dated as of April 1, 1998 between Avista Corporation and JPMorgan Chase Bank, N.A.
4.56	333-82165	4(a)	Indenture dated as of April 1, 1998 between Avista Corporation and The Bank of New York, as Successor Trustee.
4.57	1-3701 (with Form 8-K dated as of December 15, 2010)	4.1	Loan Agreement between City of Forsyth, Montana and Avista Corporation $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A dated as of December 1, 2010.
4.58	1-3701 (with Form 8-K dated as of December 15, 2010)	4.3	Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A, dated as of December 1, 2010.
4.59	1-3701 (with Form 8-K dated as of December 15, 2010)	4.2	Loan Agreement between City of Forsyth, Montana and Avista Corporation $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B dated as of December 1, 2010.
4.60	1-3701 (with Form 8-K dated as of December 15, 2010)	4.4	Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B, dated as of December 1, 2010.
10.1	1-3701 (with Form 8-K dated as February 11, 2011)	10.1	Credit Agreement, dated as of February 11, 2011, among Avista of Corporation, the Banks Party hereto, The Bank of New York Mellon, Keybank National Association, and U.S. Bank National Association, as Co-Documentation Agents, Wells Fargo Bank National Association as Syndication Agent and an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.
10.2	1-3701 (with Form 8-K dated as of February 11, 2011)	10.2	Bond Delivery Agreement, dated as of February 11, 2011, between Avista Corporation and Union Bank, N.A.
10.3	1-3701 (with Form 8-K dated as of December 14, 2011)	10.1	First Amendment and Waiver Thereunder, dated as of December 14, 2011, to the Credit Agreement dated as of February 11, 2011, among Avista Corporation, the Banks Party hereto, Wells Fargo Bank National Association as an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.

	Previously Filed [1]		
Exhibit	With Registration Number	As Exhibit	
10.4	1-3701 (with 2002 Form 10-K)	10(b)-3	Priest Rapids Project Product Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.5	1-3701 (with 2002 Form 10-K)	10(b)-4	Priest Rapids Project Reasonable Portion Power Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.6	1-3701 (with 2002 Form 10-K)	10(b)-5	Additional Product Sales Agreement (Priest Rapids Project) executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.7	2-60728	5(g)	Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.
10.8	2-60728	5(g)-1	Amendment to Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.
10.9	2-60728	5(h)	Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.
10.10	2-60728	5(h)-1	Amendment to Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.
10.11	1-3701 (with September 30, 1985 Form 10-Q)	1	Settlement Agreement and Covenant Not to Sue executed by the United States Department of Energy acting by and through the Bonneville Power Administration and the Company, dated as of September 17, 1985, describing the settlement of Project 3 litigation.
10.12	1-3701 (with 1981 Form 10-K)	10(s)-7	Ownership and Operation Agreement for Colstrip Units No. 3 and 4, dated as of May 6, 1981.
10.13	1-3701 (with 1992 Form 10-K)	10(s)-1	Agreements for Purchase and Sale of Firm Capacity between the Company and Portland General Electric Company dated March and June 1992.
10.14	1-3701 (with 2003 Form 10-K)	10(l)	Power Purchase and Sale Agreement between Avista Corporation and Potlatch Corporation, dated as of July 22, 2003.
10.15	[2]		Avista Corporation Executive Deferral Plan. [3]
10.16	[2]		Avista Corporation Executive Deferral Plan. [3][8]
10.17	[2]		Avista Corporation Supplemental Executive Retirement Plan. [3][8]

	Previously Filed [1]		
Exhibit	With Registration Number	As Exhibit	
10.18	[2]		Avista Corporation Supplemental Executive Retirement Plan. [3][8]
10.19	1-3701 (with 1992 Form 10-K)	10(t)-11	The Company's Unfunded Supplemental Executive Disability Plan. [3]
10.20	1-3701 (with 2007 Form 10-K)	10.34	Income Continuation Plan of the Company. [3]
10.21	1-3701 (with 2010 Definitive Proxy Statement filed March 31, 2010)	Appendix A	Avista Corporation Long-Term Incentive Plan. [3]
10.22	1-3701 (with 2010 Form 10-K)	10.23	Avista Corp. Performance Award Plan Summary. [3][9]
10.23	1-3701 (with 2010 Form 10-K)	10.24	Avista Corporation Performance Award Agreement. [3][9]
10.24	[2]		Avista Corporation Performance Award Agreement. [3][10]
10.25	1-3701 (with Form 8-K dated June 21, 2005)	10.1	Employment Agreement between the Company and Marian Durkin in the form of a Letter of Employment. [3]
10.26	1-3701 (with Form 8-K dated August 13, 2008)	10.1	Employment Agreement between the Company and Mark T. Thies in the form of a Letter of Employment. [3]
10.27	333-47290	99.1	Non-Officer Employee Long-Term Incentive Plan.
10.28	1-3701 (with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. [3][5]
10.29	1-3701 (with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. [3][6]
10.30	1-3701 (with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. [3][7]
10.31	1-3701 (with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. [3][7]
10.32	[2]		Avista Corporation Non-Employee Director Compensation.
12	[2]		Statement Re: computation of ratio of earnings to fixed charges.
21	[2]		Subsidiaries of Registrant.
23	[2]		Consent of Independent Registered Public Accounting Firm.
31.1	[2]		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).

	Previously Filed [1]		
Exhibit	With Registration Number	As Exhibit	
31.2	[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	[4]		Certification of Corporate Officers (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002).
101	[4]		The following financial information from the Annual Report on Form 10–K for the period ended December 31, 2011, formatted in XBRL (Extensible Business Reporting Language) and furnished electronically herewith: (i) the Consolidated Statements of Income; (ii) Consolidated Statements of Comprehensive Income; (iii) the Consolidated Balance Sheets; (iv) the Consolidated Statements of Cash Flows; (v) the Condensed Consolidated Statements of Equity and Redeemable Noncontrolling Interests; and (vi) the Notes to Consolidated Financial Statements.

(1) Incorporated herein by reference.

(2) Filed herewith.

(3) Management contracts or compensatory plans filed as exhibits to this Form 10-K pursuant to Item 15(b).

(4) Furnished herewith.

(5) Applies to Christy M. Burmeister-Smith, Don F. Kopczynski, James M. Kensok, David J. Meyer, Kelly O. Norwood, Richard L. Storro, Jason R. Thackston, Dennis P. Vermillion, and Roger D. Woodworth.

(6) Applies to Marian M. Durkin, Karen S. Feltes, Scott L. Morris, and Mark T. Thies.

(7) Applies to executive officers appointed after October 1, 2010. The Company does not currently have any officers that these agreements apply to.

(8) Applies to executive officers appointed after February 4, 2011. The Company does not currently have any officers that these plans apply to.

(9) Applies to awards in 2010.

(10) Applies to awards in 2011.

Avista Corporation

Computation of Ratio of Earnings to Fixed Charges

Consolidated

(Thousands of Dollars)

Years Ended December 31

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

Avista Corporation

SUBSIDIARIES OF REGISTRANT

Subsidiary	State or Country of Incorporation
Avista Capital, Inc.	Washington
Ecova, Inc.	Washington
Avista Development, Inc.	Washington
Avista Energy, Inc.	Washington
Avista Northwest Resources, LLC	Washington
Avista Power, LLC	Washington
Avista Turbine Power, Inc.	Washington
Avista Ventures, Inc.	Washington
Pentzer Corporation	Washington
Pentzer Venture Holding II, Inc.	Washington
Bay Area Manufacturing, Inc.	Washington
Advanced Manufacturing and Development, Inc.	California
Avista Capital II	Delaware
Spokane Energy, LLC	Delaware
Steam Plant Square, LLC	Washington
Steam Plant Brew Pub, LLC	Washington
Courtyard Office Center, LLC	Washington

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 2-81697, 2-94816, 033-54791, 333-03601, 333-22373, 333-33790, 333-47290, and 333-126577 on Form S-8; and in Registration Statement Nos. 333-163609 and 333-177981 on Form S-3 of our reports dated February 28, 2012, relating to the consolidated financial statements of Avista Corporation and subsidiaries (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of Accounting Standards Update No. 2009-17, *Consolidations — Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities*), and the effectiveness of Avista Corporation's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Avista Corporation for the year ended December 31, 2011.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 28, 2012

EXHIBIT 31.1

CERTIFICATION

I, Scott L. Morris, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 28, 2012

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

EXHIBIT 31.2

CERTIFICATION

I, Mark T. Thies, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 28, 2012

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

CERTIFICATION OF CORPORATE OFFICERS

(Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)

Each of the undersigned, Scott L. Morris, Chairman of the Board, President and Chief Executive Officer of Avista Corporation (the "Company"), and Mark T. Thies, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company's Annual Report on Form 10-K for the year ended December 31, 2011 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2012

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

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

Avista Corporation

As of and for the years ended December 31,

Dollars in thousands, except per share data and ratios

	2011	2010	2009	2008	2007	2001
Financial Results						
Operating revenues	$ 1,619,780	$ 1,558,740	$ 1,512,565	$ 1,676,763	$ 1,417,757	$ 1,511,751
Operating expenses	1,384,158	1,328,552	1,311,907	1,491,852	1,279,328	1,327,685
Income from operations	235,622	230,188	200,658	184,911	138,429	184,066
Interest expense	74,208	76,424	67,034	79,587	86,440	105,819
Income taxes	56,632	51,157	46,323	45,625	24,334	40,585
Income from continuing operations	103,539	94,948	88,648	74,757	38,727	68,241
Loss from discontinued operations	—	—	—	—	—	(56,085)
Net income	103,539	94,948	88,648	74,757	38,727	12,156
Net income attributable to noncontrolling interests	(3,315)	(2,523)	(1,577)	(1,137)	(252)	—
Preferred stock dividend requirements (1)	—	—	—	—	—	(2,432)
Net income attributable to Avista Corporation	$ 100,224	$ 92,425	$ 87,071	$ 73,620	$ 38,475	$ 9,724
Earnings per common share attributable to Avista Corporation, diluted:						
Earnings from continuing operations	$ 1.72	$ 1.65	$ 1.58	$ 1.36	$ 0.72	$ 1.38
Loss from discontinued operations	—	—	—	—	—	(1.18)
Total	$ 1.72	$ 1.65	$ 1.58	$ 1.36	$ 0.72	$ 0.20
Earnings per common share attributable to Avista Corporation, basic:	$ 1.73	$ 1.66	$ 1.59	$ 1.37	$ 0.73	$ 0.21
Common Stock Statistics						
Dividends paid per common share	$ 1.10	$ 1.00	$ 0.81	$ 0.69	$ 0.595	$ 0.48
Book value per common share	$ 20.30	$ 19.71	$ 19.17	$ 18.30	$ 17.27	$ 15.12
Shares of common stock:						
Outstanding at year-end	58,423	57,120	54,837	54,488	52,909	47,633
Average — basic	57,872	55,595	54,694	53,637	52,796	47,417
Average — diluted	58,092	55,824	54,942	54,028	52,263	47,435
Return on average Avista Corporation stockholders' equity:						
Total company	8.7%	8.5%	8.5%	7.7%	4.2%	1.3%
Utility only	8.4%	8.6%	9.2%	8.0%	5.8%	5.9%
Non-utility only	12.4%	7.2%	0.4%	4.9%	-3.4%	-3.4%
Common stock price:						
High	$ 26.53	$ 22.81	$ 22.44	$ 23.30	$ 25.81	$ 23.97
Low	$ 21.13	$ 18.46	$ 12.67	$ 16.58	$ 18.19	$ 10.60
Year-end close	$ 25.75	$ 22.52	$ 21.59	$ 19.38	$ 21.54	$ 13.26

(1) Preferred stock was reclassified from equity to liabilities in 2003 in accordance with a change in accounting standards. Accordingly, preferred stock dividend requirements were reclassified to interest expense effective July 1, 2003. Balance includes current portion.

Avista Corporation

As of and for the years ended December 31,

Dollars in thousands, except per share data and ratios

	2011	2010	2009	2008	2007	2001
Debt and Preferred Stock Statistics						
Pretax interest coverage:						
Including AFUDC/AFUCE	3.16(x)	2.96(x)	2.97(x)	2.45(x)	1.75(x)	1.32(x)
Excluding AFUDC/AFUCE	3.09(x)	2.91(x)	2.92(x)	2.32(x)	1.65(x)	1.29(x)
Embedded cost of long-term debt	5.76%	5.76%	5.91%	6.69%	7.84%	8.78%
Embedded cost of preferred stock	— %	— %	— %	— %	— %	7.39%
Financial Condition						
Total assets	$ 4,214,531	$ 3,940,095	$ 3,606,959	$ 3,630,747	$ 3,189,797	$ 4,210,704
Total net utility property	2,860,776	2,714,237	2,607,011	2,492,191	2,351,342	1,739,123
Utility property capital expenditures (excluding equity-related AFUDC)	239,782	202,227	205,384	219,239	205,811	119,905
Long-term debt (including current portion)	1,177,300	1,101,857	1,071,338	826,465	948,833	1,175,715
Nonrecourse long-term debt of Spokane Energy (including current portion) (2)	46,471	58,934	—	—	—	—
Long-term debt to affiliated trusts	51,547	51,547	51,547	113,403	113,403	—
Preferred stock subject to mandatory redemption (1)	—	—	—	—	—	35,000
Avista Corporation stockholders' equity	$ 1,185,701	$ 1,125,784	$ 1,051,287	$ 996,883	$ 913,966	$ 720,063

(1) Preferred stock was reclassified from equity to liabilities in 2003 in accordance with a change in accounting standards. Accordingly, preferred stock dividend requirements were reclassified to interest expense effective July 1, 2003. Balance includes current portion.

(2) Spokane Energy was consolidated effective January 1, 2010. See Note 3 of the Notes to Consolidated Financial Statements.

Avista Corporation

As of and for the years ended December 31,

	2011	2010	2009	2008	2007	2001
Avista Utilities						
Electric Operations						
Electric operating revenues (millions of dollars):						
Residential	$ 324.9	$ 296.6	$ 315.7	$ 279.6	$ 251.4	$ 158.8
Commercial	280.1	265.2	274.0	247.7	224.2	155.4
Industrial	122.6	114.8	107.7	101.8	95.2	80.4
Public street and highway lighting	6.9	6.7	6.6	6.0	5.5	3.8
Total retail	734.5	683.3	704.0	635.1	576.3	398.4
Wholesale	78.3	165.6	88.4	141.8	105.7	480.9
Sales of fuel	153.5	106.4	33.0	44.7	12.9	19.0
Other	21.9	19.0	15.4	16.9	16.2	23.9
Total electric operating revenues	$ 988.2	$ 974.3	$ 840.8	$ 838.5	$ 711.1	$ 922.2
Electric energy sales (millions of kWhs):						
Residential	3,728	3,618	3,791	3,744	3,670	3,219
Commercial	3,122	3,100	3,177	3,188	3,132	2,882
Industrial	2,147	2,099	1,948	2,059	2,084	1,891
Public street and highway lighting	26	26	26	26	26	25
Total retail	9,023	8,843	8,942	9,017	8,912	8,017
Wholesale	2,796	3,803	2,354	1,964	1,594	6,262
Total electric energy sales	11,819	12,646	11,296	10,981	10,506	14,279
Retail electric customers (average per year):						
Residential	316,762	315,283	313,884	311,381	306,737	276,845
Commercial	39,618	39,489	39,276	39,075	38,488	35,454
Industrial	1,380	1,376	1,394	1,388	1,378	1,434
Public street and highway lighting	455	449	444	434	426	402
Total retail electric customers	358,215	356,597	354,998	352,278	347,029	314,135
Retail electric customers (at year-end):						
Residential	318,694	317,451	315,297	313,660	310,701	279,129
Commercial	39,826	39,619	39,408	39,173	39,001	35,726
Industrial	1,385	1,372	1,384	1,384	1,383	1,424
Public street and highway lighting	456	453	447	440	427	415
Total retail electric customers	360,361	358,895	356,536	354,657	351,512	316,694
Revenue per residential kWh (cents)	8.71	8.20	8.33	7.47	6.85	4.93
Use per residential customer (kWh)	11,769	11,476	12,079	12,023	11,965	11,629
Revenue per commercial kWh (cents)	8.97	8.56	8.62	7.77	7.16	5.39
Use per commercial customer (kWh)	78,804	78,507	80,881	81,583	81,377	81,288
Electric energy resources (millions of kWhs):						
Hydro generation (from Company facilities)	4,534	3,494	3,766	3,851	3,689	2,564
Thermal generation (from Company facilities)	2,447	3,748	3,097	3,693	3,640	3,001
Purchased power — long-term hydro contracts	1,047	685	839	833	861	631
Purchased power — wholesale	4,388	5,315	4,152	3,253	2,959	8,624
Power exchanges	(24)	(15)	(18)	(17)	(18)	(104)
Total power resources	12,392	13,227	11,836	11,613	11,131	14,716
Energy losses and company use	(573)	(581)	(540)	(632)	(625)	(437)
Total electric energy resources	11,819	12,646	11,296	10,981	10,506	14,279

Avista Corporation

As of and for the years ended December 31,

	2011	2010	2009	2008	2007	2001
Electric Operations (continued)						
Total resources available at peak (MW):						
Company owned:						
Hydro	934	716	562	765	617	956
Thermal	822	821	781	724	830	462
Purchased power:						
Long-term hydro contracts	124	152	103	132	171	144
Other	1,043	1,216	1,068	859	684	1,991
Total resources available at peak (winter)	2,923	2,905	2,514	2,480	2,302	3,553
Net system peak demand (winter)	1,669	1,704	1,763	1,821	1,685	1,500
Wholesale obligations	712	803	608	562	367	1,734
Total requirements (winter)	2,381	2,507	2,371	2,383	2,052	3,234
Reserve margin	19%	14%	6%	4%	11%	9%
Annual load factor	61%	60%	61%	62%	61%	65%
Natural Gas Operations						
Natural gas operating revenues (millions of dollars):						
Residential	$ 219.6	$ 193.2	$ 251.0	$ 276.4	$ 264.5	$ 179.6
Commercial	111.9	98.2	135.2	152.1	148.4	104.0
Industrial and interruptible	6.7	6.5	10.0	12.2	11.3	11.2
Total retail	338.2	297.9	396.2	440.7	424.2	294.8
Wholesale	195.9	197.3	143.5	281.7	142.2	1.8
Transportation	6.7	6.5	6.1	6.3	6.6	8.6
Other	7.4	9.5	8.6	5.5	4.2	3.4
Total natural gas operating revenues	$ 548.2	$ 511.2	$ 554.4	$ 734.2	$ 577.2	$ 308.6
Natural gas therms delivered (millions of therms):						
Residential	207.2	188.5	208.0	210.1	195.7	198.4
Commercial	125.3	113.4	126.3	128.2	121.6	126.9
Industrial and interruptible	10.2	9.8	10.9	12.2	10.8	15.5
Total retail	342.7	311.7	345.2	350.5	328.1	340.8
Wholesale	510.8	468.9	398.0	345.9	223.1	4.8
Transportation and other	152.9	142.5	145.1	149.3	149.2	196.4
Total natural gas therms delivered	1,006.4	923.1	888.3	845.7	700.4	542.0
Retail natural gas customers (average per year):						
Residential	284,504	282,721	280,667	277,892	273,415	249,650
Commercial	33,540	33,431	33,214	32,901	32,327	30,355
Industrial and interruptible	293	292	300	297	302	328
Total retail natural gas customers	318,337	316,444	314,181	311,090	306,044	280,333
Retail natural gas customers (at year-end):						
Residential	286,567	285,067	282,538	280,687	277,397	253,325
Commercial	33,730	33,638	33,369	33,123	32,840	30,697
Industrial and interruptible	295	291	294	292	298	318
Total retail natural gas customers	320,592	318,996	316,201	314,102	310,535	284,340

Avista Corporation

As of and for the years ended December 31,

	2011	2010	2009	2008	2007	2001
Natural Gas Operations (continued)						
Revenue per residential therm (in dollars)	1.06	1.02	1.21	1.32	1.35	0.91
Use per residential customer (therms)	728	667	741	756	716	795
Revenue per commercial therm (in dollars)	0.89	0.87	1.07	1.19	1.22	0.82
Use per commercial customer (therms)	3,737	3,393	3,804	3,897	3,760	4,180
Heating degree days (at Spokane, Washington):						
Actual	6,861	6,320	6,976	7,052	6,539	6,800
30 year average	6,647	6,647	6,820	6,820	6,820	6,842
Actual as a percent of average	103%	95%	102%	103%	96%	99%
Ecova						
Revenues (millions of dollars)	$ 137.8	$ 102.0	$ 77.3	$ 59.1	$ 47.3	$ 13.2
Total assets (millions of dollars)	$ 292.9	$ 221.1	$ 143.1	$ 125.9	$ 108.9	$ 20.3
Other						
Revenues (millions of dollars)	$ 40.4	$ 61.1	$ 40.1	$ 45.0	$ 82.1	$ 420.2
Total assets (millions of dollars)	$ 112.1	$ 129.8	$ 63.5	$ 70.0	$ 71.4	$ 1,592.7

CORPORATE INFORMATION

COMPANY HEADQUARTERS

Spokane, Washington

AVISTA ON THE INTERNET

Financial results, stock quotes, news releases, documents filed with the Securities and Exchange Commission, and information on the company's products and services are available on Avista's Web site at www.avistacorp.com.

TRANSFER AGENT

Computershare is the company's stock transfer, dividend payment and reinvestment plan agent. Answers to many shareholder questions and requests for forms are available by visiting its Web site at www.bnymellon.com/shareowner/equityaccess.

STOCK INQUIRIES SHOULD BE DIRECTED TO:

Avista Corp.
c/o Computershare
P.O. Box 358035
Pittsburgh, PA 15252-8035
800.642.7365
e-mail: shrrelations@bnymellon.com

INVESTOR INFORMATION

A copy of the company's financial reports, including the reports on Forms 10-K and 10-Q filed with the Securities and Exchange Commission, will be provided without charge upon request to:
Avista Corp.
Investor Relations
P.O. Box 3727 MSC-19
Spokane, WA 99220-3727
800.222.4931

ANNUAL MEETING OF SHAREHOLDERS

Shareholders are invited to attend the company's annual meeting to be held at 8:15 a.m. PDT on Thursday, May 10, 2012, at Avista Corp. headquarters, 1411 East Mission Avenue, Spokane, Washington.

The annual meeting will be webcast. Please go to www.avistacorp.com to preregister for the webcast and to listen to the live webcast. The webcast will be archived at www.avistacorp.com for one year to allow shareholders to listen at their convenience.

EXCHANGE LISTING

Ticker Symbol: AVA
New York Stock Exchange

CERTIFICATIONS

On May 27, 2011, the Chief Executive Officer (CEO) of Avista Corp. filed a Section 303A.12(a) Annual CEO Certification with the New York Stock Exchange. The CEO Certification attests that the CEO is not aware of any violations by the company of NYSE's Corporate Governance Listing Standards.

Avista Corp. has included as exhibits to its annual report on Form 10-K for the year 2011, filed with the Securities and Exchange Commission, certifications of Avista's Chief Executive Officer and Chief Financial Officer regarding the quality of Avista's public disclosure in compliance with Section 302 of the Sarbanes-Oxley Act of 2002.

This annual report contains forward-looking statements regarding the company's current expectations. These statements are subject to a variety of risks and uncertainties that could cause actual results to differ materially from the expectations. These risks and uncertainties include, in addition to those discussed herein, all factors discussed in the company's annual report on Form 10-K for the year 2011. Our 2011 annual report is provided for shareholders. It is not intended for use in connection with any sale or purchase of or any solicitation of others to buy or sell securities.

The 2011 annual report is produced through a partnership of talented employees and companies within Avista's service area.
Many thanks for their assistance –
Klündt | Hosmer, J. Craig Sweat Photography, Dean Davis Photography, Ben Hider Photography and Lawton Printing

HELP US HELP THE ENVIRONMENT

Managing costs is a primary goal for Avista. You can help us meet this goal by agreeing to receive future annual reports and proxy statements electronically. This service saves on the costs of printing and mailing, provides timely delivery of information, and helps protect our environment by saving energy and decreasing the need for paper, printing and mailing materials. For more information, please visit our Web site www.avistacorp.com.

In our commitment to sustainability, the forest products used in the 2011 annual report are FSC certified – sustainably harvested from the forest of origin and responsibly managed through the supply chain.

FSC
MIX
Paper
FSC® C015667

AVISTA Corp.
1411 EAST MISSION AVENUE | SPOKANE, WASHINGTON 99202 | 509.489.0500 | AVISTACORP.COM