Energy for a smart future

annual report : 2009

Avista Corp.

IN TODAY'S WORLD, WE MUST REMEMBER THAT EVERYTHING WE DO HAS RIPPLE EFFECTS AROUND THE GLOBE, ESPECIALLY GIVEN TWO IMPERATIVES –

people and our planet

On the cover: Avista's future is filled with growth, optimism, spirit and energy, much like this young lady – Anne Ogle, six-year-old daughter of Avista Gas Engineering Compliance Technician Brad Ogle. It is with today's children in mind that Avista is committed to a future of sustainable energy.

On the facing page: Avista's "Sun Car" – a Plug-in Hybrid Electric Vehicle – is charged with battery power generated from clean, renewable sources, such as solar panels, which we've installed on the roof of our corporate office. As we move forward with more renewable energy projects, we're gaining keen insights into what the future looks like for our company and our customers.

TO OUR SHAREHOLDERS

finding the best ways forward

AS THE SECOND DECADE OF THE NEW MILLENNIUM BEGINS, OUR REFLECTIONS ON AVISTA'S ACHIEVEMENTS OVER THE PAST 10 YEARS GIVE ME A GREAT SENSE OF PRIDE. I AM REMINDED OF THE MANY CHALLENGES WE FACED AND THE SIGNIFICANT GOALS WE ACHIEVED. TODAY WE ARE FINANCIALLY SOUND AND ONE OF THE CLEANEST, MOST EFFICIENT UTILITIES IN THE COUNTRY. FOR AVISTA, OUR PAST HAS GIVEN US THE RESILIENCE TO MEET THE FUTURE HEAD ON. BEFORE WE LOOK AHEAD, I'D LIKE TO BRIEFLY RECAP SOME HIGHLIGHTS OF 2009.

WE HAD A POSITIVE AND SUCCESSFUL YEAR:

- Earnings per share growth of 16 percent;
- Dividend increase of 17 percent for an annualized dividend of $0.84 per share; targeting a dividend payout ratio of 60 to 70 percent;
- Credit rating upgrade from Fitch and positive ratings outlooks from Moody's and Standard and Poor's;
- Favorable refinancing activities in a challenging market, saving our customers millions of dollars over the next decade, lessening our business risk and improving our financial performance; and
- Stable earnings at Advantage IQ, despite a challenging economy, with 31 percent growth in revenue over 2008.

implementing knowledge and

We successfully reset general rates for electricity and natural gas in the three western states we serve. And we will continue to work with state regulators to earn rates of return closer to those authorized by regulators.

Recovering the costs of doing business through rates, however, was more contentious in 2009, due in part to the weak economy, regional job losses, legislative uncertainties and an extremely harsh winter. But when a family sits down for dinner, the energy they need to cook their meal, to light the table and to heat the room must be there. So, we will continue with our annual $210 million capital investments to assure our customers get the reliable energy they expect.

Another achievement of 2009 was the receipt of a new 50-year license for our five hydroelectric projects on the Spokane River. In addition, we celebrated the 50th anniversary of our Noxon Rapids hydroelectric project in Montana. Our long-standing commitment to renewable hydroelectric generation and environmental stewardship is strengthened by the partnerships formed through these endeavors with stakeholders including local, state and federal agencies, non-governmental groups like Trout Unlimited and the Sierra Club, and concerned individuals. We will continue to nurture these important relationships while investigating opportunities for further renewable energy solutions.

Our company is well-grounded by the work we're doing to help our customers get the most value from their energy dollar in their homes and businesses. Later in this report you'll read about the success they are having in attaining significant energy efficiency savings. But, for the future, our collective attention must turn to managing energy demand. By using energy more wisely – not just by using less – we can improve our environmental footprints and positively impact our economy. I believe alignment of new public policies and regulations concerning energy efficiency will truly make a difference in our future.

But getting alignment isn't easy. We are working to cut through the political rhetoric of "green," to more clearly focus the conversation on options and opportunities that encourage energy efficiency as the preferred source of new energy. That's also why we are advocating for state policies and regulations that provide Avista with the opportunity to recover all of the costs associated with our investments in conservation as a resource. And we are involved in the discussions on fair cap and trade and renewable energy legislation, to level the playing field so our customers don't pay more just because we already invested in clean generation and energy efficiency. We're carefully examining how new technology is impacting our industry and our customers as we incorporate smart grid components to bring value to our customers and fair returns to our investors.

The stimulus fund grants we were selected to receive from the U.S. Department of Energy in late 2009 will give us added leverage to significantly accelerate our use of smart circuit technology, to enhance the efficiency and reliability in our own system and to reduce our carbon emissions. And in partnership with some

technology at the speed of value

of the best organizations in the industry, we'll develop the first smart grid city in the Pacific Northwest to carefully test new technology from generation to the customer.

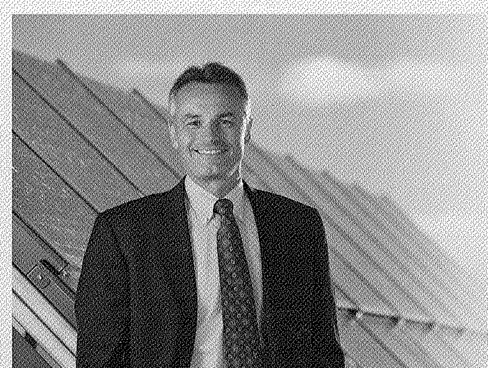
We know that this is just the beginning of the journey into distributed and intelligent energy services. And we must be ever mindful that if these new technologies are to be truly successful, it will be because of the human element that is integral to their use.

People increasingly demand more energy to power what they do every day. And we must look to meet this growing need with fewer employees, as the largest generation of all time – Baby Boomers – is retiring. We've planned for this shift in our demographics, and we continue to develop our work force to keep ideas fresh and leadership strong.

The worldwide discourse on climate change is no longer only about the rising demand for energy, however; it is about clean energy. As our society moves from being passive to active, informed users of energy, it will ultimately be people – like the dedicated employees of Avista – who will determine how successfully we can implement the emerging clean energy technologies. We will be prepared.

Companies that can deliver effective energy solutions will be the leaders and will enable their customers to make wise decisions. At Avista, we have been attentive to those opportunities since our inception. And it shows. The foresight that spawned the innovations you'll see noted later in this report – Itron, ReliOn and Advantage IQ, among others – is woven throughout our company's culture. It positions us well to continue our legacy of energy for a smart future.

What will our company look like in the next decade or two? I am sure it will be different from today, but many things will remain unchanged. We are – and will continue to be – focused on the deliberate design of what lies ahead, with the clear intent of meeting the needs of our customers, our investors, our employees and the communities we serve – implementing knowledge and technology at the speed of value.



Scott Morris

Scott L. Morris
Chairman, President and Chief Executive Officer

where does Avista's future come from?

1903 World's Longest Transmission Line

1910 Nation's First Automatic Control for the Electric Stove

1915 World's Highest Spillway – Long Lake Dam

1940

innovation forward

Where does the future begin? For Avista, it began in 1889 along the shores of a rumbling river in the town of Spokane Falls, in the Washington Territory. Bringing power to the homes and businesses that were growing up in the mining and timber region of the Inland Northwest required the same kind of foresight, innovation and tenacity that is integral to the operation of our company today.

Avista is meeting the growing energy needs of our customers by assuring that our company's operations are relevant to a rapidly changing society. Our strength comes in our ability to recognize emerging trends, and then use our intuition, knowledge and persistence to assure they bring value to our customers and our investors.

Our core business – Avista Utilities – is well positioned to integrate the clean technology of the 21st century into our generation, transmission and distribution system. And we are doing this while maintaining one of the smallest carbon footprints of large energy producers in the country.

As the recipient of two matching grants for smart grid projects under the American Recovery and Reinvestment Act, we are doing what we do best – building a solid, state-of-the-art energy delivery and communications system that will enhance the reliability and efficiency of our electric grid. In partnership with leaders in the research and development of power technology, over the next five years we plan to pilot the first "smart city" in the Pacific Northwest. We will install and test intelligent technology from the generating plant to the home – learning first-hand how smart our system can be and how to best help our customers make use of the insight they will receive about their own energy use.

On this spread: Avista's employees are at the forefront of the future. Through their innovation, our sustainable future is evolving through relationships with mutually beneficial outcomes. Our partnership with Washington State University, Schweitzer Engineering Laboratories, Itron, Hewlett Packard and the City of Pullman, Wash., will infuse new technology over power lines to create the first smart community in the Pacific Northwest. And through a partnership with a local producer, Avista is testing clean biodiesel fuel, a renewable and cost-effective resource for our service trucks.

FIRST OF THREE COFFIN MEDALS (EDISON AWARD) FOR DISTINGUISHED CONTRIBUTIONS TO THE DEVELOPMENT OF ELECTRIC LIGHT AND POWER FOR THE CONVENIENCE OF THE PUBLIC AND BENEFIT OF THE INDUSTRY

1977	WORLD LEADER IN UTILITY METERING INFORMATION – ITRON – FOUNDED
1979	SERVICE TERRITORY-WIDE CUSTOMER ENERGY EFFICIENCY PROGRAMS INITIATED – UNINTERRUPTED FOR OVER 30 YEARS
1983	NATION'S FIRST PLANT CONSTRUCTED SOLELY FOR PRODUCING POWER FROM WOOD WASTE – KETTLE FALLS.

sustain ability

At home, our customers are embracing the opportunities to make informed choices about managing their energy bills. In 2009 they saved more than 82 million kilowatts of electricity and 2.3 million therms of natural gas – roughly enough to heat and light 9,000 homes a year – making good use of Avista's "Every Little Bit" energy efficiency rebate and incentive programs.

Extending Avista's knowledge base and experience into the workplace, Advantage IQ, a non-utility subsidiary, is the market leader in serving the unique energy information needs of Fortune 500, multi-site companies throughout North America. With an increasing number of businesses concerned with their facility expenses, their carbon footprints and the integration of sustainable practices into their operations, Advantage IQ delivers actionable intelligence to customers. The 2009 acquisition of Ecos, a provider of energy efficiency solutions, steps up Advantage IQ's role from being a manager of utility information to being a trusted advisor to companies who seek to be exceptional stewards of their resources. Under the new leadership of Jeff Heggedahl and his executive team, Advantage IQ is focused on the future, ready to meet the evolving needs of customers through sustained energy management excellence.

From the generating plant to the natural gas pipeline and from the home to the workplace, Avista's future is grounded on a solid legacy of innovation, sustainability and leadership. We are committed to keeping our eye on the horizon, looking for new opportunities, while realistically weighing the potential costs and risks, to drive value for our customers and our shareholders. ✦

On the facing page: Natural gas is the cleanest fossil fuel and remains readily available for the foreseeable future, according to Avista's 2009 Integrated Resource Plan. In 2009, Avista netted more than 2,000 new natural gas customers. And system enhancements like the $3 million East Medford (Ore.) Reinforcement Project, phase 3, are making it possible for customers like Avista employee Brad Ogle and his daughter Anne to continue enjoying the safe, cost-effective use of natural gas in their homes and businesses.

where does Avista's future come from?

1995

National Model to Fund Customer Energy Efficiency Programs

North America Market Leader, Multi-Site Facility Expense Management Founded – Advantage IQ

1998 World Leader in Modular PEM Fuel Cells Founded – ReliOn

1999 National Model for Alternative Relicensing Process – Clark Fork Hydro Projects Living License

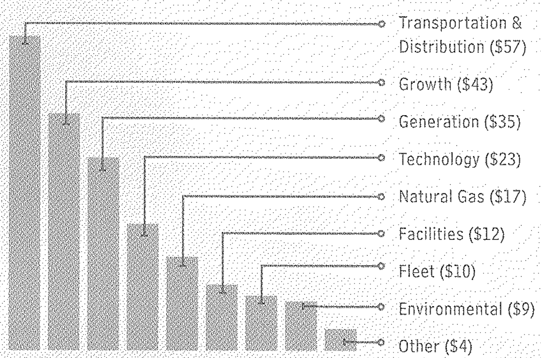
2003–2006 Regional major power grid Project – Avista's five-year, $120 million transmission upgrade project

2007 National Outstanding Stewardship of America's Waters Award for Excellence in River Stewardship – 8th consecutive Award

2009 In North America named number one electric and natural gas utility website for customer self-service functionality, www.avistautilities.com

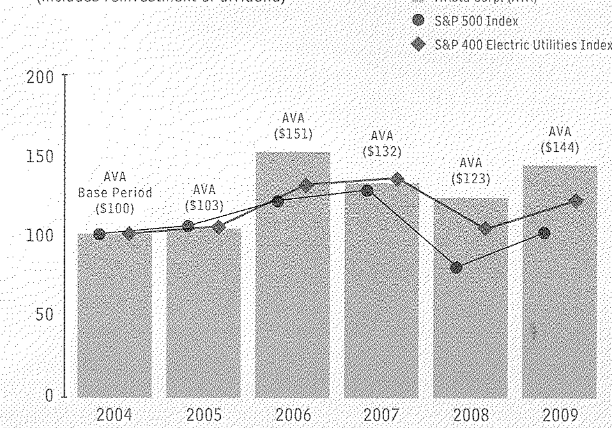
2010 CAPITAL BUDGET

(total capital budget $210 million) ($ in millions)



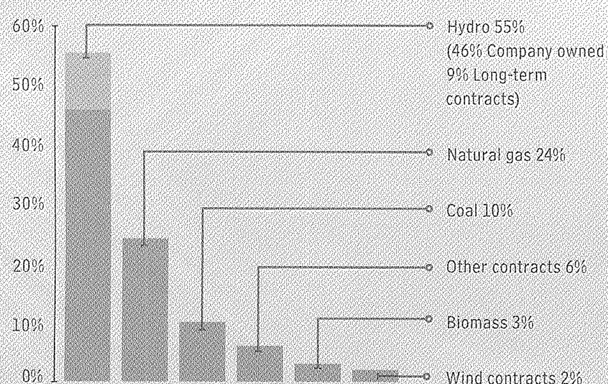
TOTAL RETURN TO SHAREHOLDERS

(includes reinvestment of dividend)



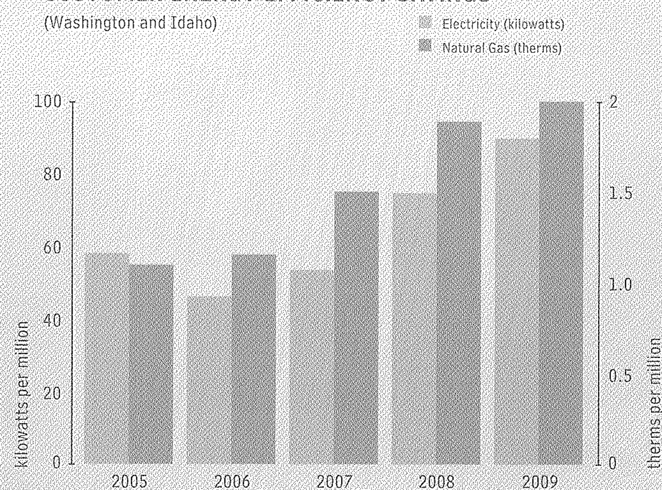
ELECTRICITY GENERATION RESOURCE MIX

(as of December 31, 2009)



CUSTOMER ENERGY EFFICIENCY SAVINGS

(Washington and Idaho)



(dollars in thousands except statistics and per share amounts or as otherwise indicated)	2009	2008	2007
FINANCIAL RESULTS			
Operating revenues	$ 1,512,565	$ 1,676,763	$ 1,417,757
Operating expenses	1,311,907	1,491,852	1,279,328
Income from operations	200,658	184,911	138,429
Net income	88,648	74,757	38,727
Net income attributable to Avista Corporation	87,071	73,620	38,475
Earnings per common share attributable to Avista Corporation, diluted	1.58	1.36	0.72
Earnings per common share attributable to Avista Corporation, basic	1.59	1.37	0.73
Dividends paid per common share	0.810	0.690	0.595
Book value per common share	$ 19.17	$ 18.30	$ 17.27
Average common shares outstanding	54,694	53,637	52,796
Actual common shares outstanding	54,837	54,488	52,909
Return on average Avista Corporation stockholders' equity	8.5%	7.7%	4.2%
Common stock closing price	$ 21.59	$ 19.38	$ 21.54
OPERATING RESULTS			
Avista Utilities			
Retail electric revenues	$ 703,951	$ 635,102	$ 576,260
Retail kWh sales (in millions)	8,942	9,017	8,912
Retail electric customers at year-end	356,536	354,657	351,512
Wholesale electric revenues	$ 88,414	$ 141,744	$ 105,729
Wholesale kWh sales (in millions)	2,354	1,964	1,594
Sales of fuel	$ 32,992	$ 44,695	$ 12,910
Other electric revenues	15,426	16,916	16,231
Retail natural gas revenues	396,203	440,692	424,246
Wholesale natural gas revenues	143,524	281,668	142,167
Transportation and other natural gas revenues	$ 14,691	$ 11,847	$ 10,820
Total therms delivered (in thousands)	888,301	845,710	700,433
Retail natural gas customers at year-end	316,201	314,102	310,535
Net income attributable to Avista Corporation	$ 86,744	$ 70,032	$ 43,822
Advantage IQ			
Revenues	$ 77,275	$ 59,085	$ 47,255
Net income attributable to Avista Corporation	5,329	6,090	6,651
Other			
Revenues	$ 40,089	$ 45,014	$ 82,139
Net loss attributable to Avista Corporation	(5,002)	(2,502)	(11,998)
FINANCIAL CONDITION			
Total assets	$ 3,606,959	$ 3,630,747	$ 3,189,797
Long-term debt (including current portion)	1,071,338	826,465	948,833
Long-term debt to affiliated trusts	51,547	113,403	113,403
Total Avista Corporation stockholders' equity	$ 1,051,287	$ 996,883	$ 913,966

board of directors

Erik J. Anderson, 51
President, Westriver Capital
Kirkland, Washington
Director since 2000

Kristianne Blake, 56
President, Kristianne Gates Blake, P.S.
Spokane, Washington
Director since 2000

Brian W. Dunham, 52
President & CEO, Northwest Pipe Co.
Vancouver, Washington
Director since 2008

Roy L. Eiguren, 58
President
Eiguren Public Law & Policy, PLLC
Boise, Idaho
Director since 2002

Jack W. Gustavel, 70
Chairman & CEO
Idaho Independent Bank
Coeur d'Alene, Idaho
Director since 2003

John F. Kelly, 65
President & CEO
John F. Kelly & Associates
Coral Gables, Florida
Director since 1997

Scott L. Morris, 52
Chairman of the Board,
President & CEO
Avista Corp.
Spokane, Washington
Director since 2007

Michael L. Noël, 68
President, Noël Consulting Company
Prescott, Arizona
Director since 2004

Marc F. Racicot, 61
Bigfork, Montana
Director since 2009

Heidi B. Stanley, 53
Spokane, Washington
Director since 2006

R. John Taylor, 60
Chairman & CEO
CropUSA Insurance Agency
Lewiston, Idaho
Director since 1985

board committees

Corporate Governance/ Nominating Committee
Kristianne Blake
Heidi B. Stanley
R. John Taylor
John F. Kelly – Chair

Executive Committee
Kristianne Blake
Jack W. Gustavel
R. John Taylor
Scott L. Morris – Chair

Audit Committee
Roy L. Eiguren
Michael L. Noël (Financial Expert)
Heidi B. Stanley
Kristianne Blake – Chair

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

Finance Committee
Brian W. Dunham
Jack W. Gustavel
Marc F. Racicot
Erik J. Anderson – Chair

Energy, Environmental & Operations Committee
Erik J. Anderson
Jack W. Gustavel
Marc F. Racicot
Roy L. Eiguren – Chair

corporate & business unit officers

Scott L. Morris, 52
Chairman of the Board,
President & CEO

Mark T. Thies, 46
Senior Vice President & CFO

Marian M. Durkin, 56
Senior Vice President,
General Counsel &
Chief Compliance Officer

Karen S. Feltes, 54
Senior Vice President &
Corporate Secretary

Dennis P. Vermillion, 48
Senior Vice President &
Environmental Compliance Officer
President, Avista Utilities

Christy M. Burmeister-Smith, 53
Vice President, Controller &
Principal Accounting Officer

James M. Kensok, 51
Vice President & CIO

Don F. Kopczynski, 54
Vice President

David J. Meyer, 56
Vice President &
Chief Counsel for Regulatory
& Governmental Affairs

Kelly O. Norwood, 51
Vice President

Richard L. Storro, 59
Vice President

Jason R. Thackson, 39
Vice President

Roger D. Woodworth, 53
Vice President

Diane C. Thoren, 57
Treasurer

Jeffrey D. Heggedahl, 45
President & CEO, Advantage IQ


2009 form 10-K
footprints for the future

AVISTA CORP (AVA)

FORM 10-K

Filed: February 26, 2010 (Period: December 31, 2009)

Annual report which provides a comprehensive overview of the company for the past year.

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, 2009** 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, together with Preferred Share Purchase Rights appurtenant thereto	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 $973,684,544 based on the last reported sale price thereof on the consolidated tape on June 30, 2009.

As of January 31, 2010, 54,852,750 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 13, 2010	Part III, Items 10, 11, 12, 13 and 14

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SELECTED FINANCIAL DATA

** = not an applicable item in the 2009 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
APB	– Accounting Principles Board
Advantage IQ	– Advantage IQ, Inc., provider of facility information and cost management services for multi-site customers throughout North America, subsidiary of Avista Capital
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 Mechanism	– 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 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
Energy	– The amount of electricity produced or consumed over a period of time, measured in KWH or MWH
EITF	– Emerging Issues Task Force
ERM	– The Energy Recovery Mechanism in the state of Washington
FASB	– Financial Accounting Standards Board

ACRONYM/TERM	MEANING
FIN	– Financial Accounting Standards Board Interpretation
FERC	– Federal Energy Regulatory Commission
IPUC	– Idaho Public Utilities Commission
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 Council
Noxon Rapids	– The Noxon Rapids Hydroelectric Generating Project, located on the Clark Fork River in Montana
OASIS	– Open Access Same-Time Information System
OPUC	– The Public Utility Commission of Oregon
PCA	– The Power Cost Adjustment mechanism in the state of Idaho
PLP	– Potentially liable party
PUD	– Public Utility District
PURPA	– The Public Utility Regulatory Policies Act of 1978
RTO	– Regional Transmission Organization
SFAS	– Statement of Financial Accounting Standards
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

PART I

Our Annual Report on Form 10-K contains forward-looking statements, which should be read with the cautionary statements and important factors included at "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Forward-Looking Statements." 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 are subject to a variety of risks and uncertainties and other factors. Many of these factors are beyond our control and could have a significant effect on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in our statements.

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.

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, 2009, we employed 1,538 people in our utility operations and 897 people in our subsidiary businesses. Our corporate headquarters are in Spokane, Washington, the hub of the Inland Northwest. Historically, the primary industries in our service areas were mining, lumber and wood products, military and agriculture. Although they remain important, our economy is now more diversified. Health care, higher education, finance, manufacturing and tourism are also important sectors. Retail trade, governmental and professional services have expanded to serve a larger population.

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.
- **ADVANTAGE IQ** — an indirect subsidiary of Avista Corp. (approximately 74 percent owned as of December 31, 2009) that provides sustainable utility expense management solutions to its customers that are generally multi-site companies across North America to assess and manage utility costs and usage. Advantage IQ's primary product lines include processing, payment and auditing of energy, telecom, waste, water/sewer and lease bills, as well as strategic management services.

We have other businesses, including sheet metal fabrication, venture fund investments and real estate investments, as well as certain natural gas storage facilities held by Avista Energy, Inc. (Avista Energy). These activities do not represent a reportable business segment and are conducted by various indirect subsidiaries of Avista Corp. 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.

Advantage IQ, Avista Energy, and various other companies are subsidiaries of Avista Capital, Inc. (Avista Capital) which is a direct, wholly owned subsidiary of Avista Corp. Our total Avista Corp. stockholders' equity was $1,051.3 million as of December 31, 2009, of which $81.2 million represented our investment in Avista Capital.

See "Item 6. Selected Financial Data" and "Note 27 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 2009, we supplied retail electric service to 356,000 customers and retail natural gas service to 316,000 customers across our entire service territory. See "Item 2. Properties" for further information on our utility assets.

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 capacity and energy, and 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 wholesale electric capacity and energy and fuel as part of the process of acquiring and balancing resources to serve our load obligations. These transactions range from terms of one hour up to multiple years. We make continuing projections of:

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

On the basis of these projections, 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.

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. Our Open Access Same-Time Information System (OASIS) is part of the Joint Transmission Services Information Network that covers much of the United States. Transmission revenues were $9.3 million in 2009, $9.5 million in 2008 and $10.6 million in 2007.

ELECTRIC REQUIREMENTS

Our peak electric native load requirement for 2009 occurred on December 8, 2009 at which time our total load was 2,371 MW consisting of:

- native load of 1,763 MW,
- long-term wholesale obligations of 259 MW, and
- short-term wholesale obligations of 349 MW.

At that time our maximum resource capacity available was 2,514 MW, which included:

- company-owned electric generation of 1,343 MW,
- long-term hydroelectric contracts with certain Public Utility Districts (PUDs) of 103 MW,
- other long-term wholesale contracts of 279 MW, and
- short-term wholesale purchases of 789 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 2009, our facilities had a total net capability of 1,776 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 2010 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 529 average megawatts (aMW) (or 4.6 million MWhs). Hydroelectric resources provided 526 aMW for 2009, 535 aMW for 2008 and 519 aMW for 2007.

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

	2009	2008	2007
Noxon Rapids	1,673	1,696	1,591
Cabinet Gorge	1,061	1,081	1,088
Post Falls	84	85	83
Upper Falls	52	78	63
Monroe Street	104	104	100
Nine Mile	106	105	100
Long Lake	487	497	471
Little Falls	199	205	193
Total company-owned hydroelectric generation	3,766	3,851	3,689
Long-term hydroelectric contracts with PUDs	839	833	861
Total hydroelectric generation	4,605	4,684	4,550

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. Natural gas may be used as an alternate fuel. 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. We did not operate these generating units significantly in 2009, 2008 and 2007. 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:

	2009	2008	2007
Coyote Springs 2	1,559	1,696	1,623
Colstrip	1,277	1,758	1,673
Kettle Falls GS	184	201	299
Northeast CT and Rathdrum CT	44	15	20
Boulder Park and Kettle Falls CT	33	23	25
Total thermal generation	3,097	3,693	3,640

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 by the Federal Energy Regulatory Commission (FERC) as required by the Energy Policy Act of 2005 (Energy Policy Act), we are required to purchase generation from qualifying facilities. This includes small hydroelectric and cogeneration projects at rates approved by the Washington Utilities and Transportation Commission (WUTC) and the Idaho Public Utilities Commission (IPUC). These contracts expire at various times between 2015 and 2027. These contracts were not a significant source of power resources in 2009, 2008 and 2007.

See "Avista Utilities Operating Statistics — Electric Operations — Electric Energy Resources" for annual quantities of purchased power, wholesale power sales and power from exchanges in 2009, 2008 and 2007.

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.

In March 2001, we received a 45-year operating license from the FERC for the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) and the Noxon Rapids Hydroelectric Generating Project (Noxon Rapids). 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 "Clark Fork Settlement Agreement" in "Note 24 of the Notes to Consolidated Financial Statements" for disclosure 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.

We own and operate six hydroelectric plants on the Spokane River. Five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls, which have a total present capability of 144.1 MW) are under one FERC license 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 FERC issued a new 50-year license for the Spokane River Project on June 18, 2009.

The license incorporated certain conditions that were included in the December 2008 Settlement Agreement with United States Department of Interior (DOI) and the Coeur d'Alene Tribe (the 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. Various issues that were appealed under the Washington 401 Water Quality Certification were subsequently resolved through settlement.

As part of the Settlement Agreement with the Washington Department of Ecology (DOE), we are currently engaged with the DOE and the Environmental Protection Agency (EPA) Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On February 12, 2010, the DOE submitted the TMDL for the EPA's review and approval. Once the TMDL process is completed, and our level of responsibility related to low dissolved oxygen in Lake Spokane is established, we will identify potential mitigation measures. It is not possible to provide cost estimates at this time because the mitigation measures have not been fully indentified or approved by the DOE. It is also possible the TMDL will be appealed by one or more parties if it is approved by the EPA.

We are implementing the environmental and operational conditions required in the license for the Spokane River Project. The estimated cost to implement the license conditions for the five hydroelectric plants is $334 million over the 50 year license term. This will increase the Spokane River Project's cost of power by about 40 percent, while decreasing annual generation by approximately one-half of one percent. Costs to implement mitigation measures related to the TMDL are not included in these cost estimates.

The IPUC and the WUTC approved the recovery of licensing costs through general rate cases in 2009. We will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to the licensing of the Spokane River Project.

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 hourly, daily, monthly and annual durations, which vary widely because of the factors that influence demand. Our average hourly load was 1,082 aMW in 2009, 1,102 aMW in 2008 and 1,089 aMW in 2007.

The following is a forecast of our average annual energy requirements and resources for 2010, 2011, 2012 and 2013:

FORECASTED ELECTRIC ENERGY REQUIREMENTS AND RESOURCES (aMW)

	2010	2011	2012	2013
Requirements:				
System load	1,101	1,130	1,152	1,174
Contracts for power sales	140	139	139	139
Total requirements	1,241	1,269	1,291	1,313
Resources:				
Company-owned and contract hydro generation (1)	526	520	509	511
Company-owned base load thermal generation (2)	237	247	235	234
Company-owned other thermal generation (2)	291	285	296	296
Contracts for power purchases	625	482	468	466
Total resources	1,679	1,534	1,508	1,507
Surplus resources	438	265	217	194
Additional available energy (3)	142	152	152	142
Total surplus resources	580	417	369	336

(1) *The forecast assumes near normal hydroelectric generation (decline is related to changes in contracts with PUDs).*

(2) *Excludes the Northeast CT and Rathdrum CT. We generally use these 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 the third quarter of 2009, we filed our 2009 Electric Integrated Resource Plan (IRP) with the WUTC and the IPUC. The IRP identifies a strategic resource portfolio that meets future electric load requirements, promotes environmental stewardship and meets our obligation to provide reliable electric service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project. Highlights of the IRP include:

- Up to 150 MW of wind power by 2012 (which equates to approximately 50 average megawatts),
- An additional 200 MW of wind power by 2022,
- 750 MW of clean-burning natural gas-fired generation facilities,
- Aggressive energy efficiency measures to reduce generation requirements by 26 percent or 339 MW,
- Transmission upgrades to integrate new generation resources into our system, and
- Hydroelectric upgrades at existing facilities to generate additional renewable energy.

We are subject to Washington state renewable energy portfolio standards and must obtain a portion of our electricity from qualifying renewable resources or through purchase of renewable energy credits. Our IRP identified that additional qualifying renewable energy is needed by 2016 and that new capacity and energy resources are needed by 2018. Based on resource acquisition goals identified in the IRP, we evaluated proposals from suppliers to provide us with up to 35 average megawatts (which equates to approximately 105 MW of wind power) of long-term qualified renewable energy by the end of 2012.

In 2008, we completed the acquisition of the development rights for a wind generation site. We considered developing this site and/or acquiring additional renewable resources a few years early by taking advantage of certain federal and state tax incentives. However, after detailed analysis, we decided to postpone renewable resource acquisitions, including the potential construction of a wind generation project until the 2014-2015 timeframe.

Future generation resource decisions will be impacted by legislation for restrictions on greenhouse gas emissions and renewable energy requirements.

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 Avista Turbine Power, Inc. (ATP), an affiliate of Avista Energy, through 2026 under a power purchase agreement. ATP conveyed the majority of its rights and obligations under this agreement to Shell Energy through the end of 2009. ATP conveyed these rights and obligations to Avista Corp. (Avista Utilities) beginning in January 2010.

In Idaho, the net costs of the Lancaster power purchase agreement were determined to be prudent by the IPUC and are currently being recovered through the Power Cost Adjustment mechanism. We will include recovery of the net costs in base rates in our next general rate case filing. In Washington, the WUTC approved deferral of the net costs subject to a future determination of the power purchase agreement being a prudent resource acquisition, and review and approval of the costs in our next general rate case filing.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Environmental Issues and Other Contingencies" for information related 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, continue to 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.

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 also optimize natural gas resources by using excess resources and market opportunities to generate economic value that reduces retail rates. Wholesale sales are delivered through wholesale market facilities outside of our natural gas distribution system.

We make continuing projections of our natural gas loads and assess available natural gas resources. Forward natural gas contracts are typically for monthly delivery periods. However, daily variations in natural gas demand can be significantly different than monthly demand projections. 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 as much as four 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 purchase a significant portion of our natural gas supply requirements in short-term and spot markets. Natural gas resource optimization activities include:

- wholesale market sales of surplus natural gas supplies,
- purchases and sales of natural gas to use underutilized pipeline capacity, and
- sales of excess natural gas 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. The total volume transported on behalf of our transportation customers for 2009, 2008 and 2007 was 144.6, 148.7 and 148.8 million therms, representing 16 percent, 18 percent and 21 percent of total system deliveries.

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 244.1 million therms.

We also contract with Northwest Natural Gas for storage at the Mist Natural Gas storage facility. This contract is for 5 million therms of capacity and up to 150 million therms of deliverability. This contract expires on March 31, 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.

Avista Energy controls 30.3 million therms of our capacity at Jackson Prairie and in conjunction with the asset sales agreement has assigned this capacity to Shell Energy through April 30, 2011. After that date, it is our intent to transfer this capacity to Avista Utilities for use in utility operations subject to state regulatory approval.

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 service 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 is made on the basis of net investment, operating expenses and revenues as of a date prior to the date of the request. Although the current ratemaking process 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 results in a lag between the time we incur costs and the time when we can start recovering the costs through rates.

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 26 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 26 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. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Avista Utilities — Regulatory Matters — Purchased Gas Adjustments" and "Note 26 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 OASIS 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.

REGIONAL TRANSMISSION ORGANIZATIONS

FERC Order No. 2000 (issued in 2000) required all utilities subject to FERC regulation to file a proposal to form a Regional Transmission Organization (RTO), or a description of efforts to participate in an RTO, and any existing obstacles to RTO participation. While it has not formally withdrawn Order No. 2000, the FERC issued orders and made public policy statements indicating its support for the development and formation of regional independently-governed transmission organizations developed by such regions, but that do not necessarily meet all of the RTO functions and characteristics outlined in Order No. 2000. These include FERC Order No. 890 (issued in 2007), which required transmission providers 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 RTO in the region. ColumbiaGrid, a Washington nonprofit membership corporation, was formed to improve the operational efficiency, reliability, and planned expansion of the transmission grid in the Pacific Northwest. ColumbiaGrid members, including Avista Corp., elected an independent slate of directors to a three-member board in August 2006. ColumbiaGrid's members and stakeholders continue to publicly assess new responsibilities and functions that ColumbiaGrid may undertake. ColumbiaGrid's transmission planning and expansion functional agreement was accepted by the FERC and was signed by a number of Pacific Northwest parties, including Avista Corp. We will continue to assess the benefits of entering into other functional agreements with ColumbiaGrid.

RELIABILITY STANDARDS

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

The FERC subsequently certified the North American Electricity Reliability Council (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. As of January 2010, the FERC has approved 104 NERC Reliability Standards, including nine 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. We have continued to successfully demonstrate our compliance with these standards.

ENVIRONMENTAL ISSUES

We are subject to environmental regulation by federal, state and local authorities. The generation, transmission, distribution, service and storage facilities in which we have an ownership interest 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.

In addition to the information provided in this section, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Environmental Issues and Other Contingencies."

FISHERIES — A number of species of fish in the Northwest, including the Snake River sockeye salmon and fall chinook salmon, the Kootenai River white sturgeon, the upper Columbia River steelhead, the upper Columbia River spring chinook salmon and the bull trout, are listed as threatened or endangered under the Federal Endangered Species Act. Thus far, measures that were adopted and implemented to save the Snake River sockeye salmon and fall chinook salmon have not directly impacted generation levels at any of our hydroelectric facilities. We purchase power under long-term contracts with certain PUDs on the Columbia River that are directly impacted by ongoing mitigation measures for salmon and steelhead. The reduction in generation at these projects is relatively minor, resulting in minimal economic impact on our operations at this time. We cannot predict the economic costs to us resulting from future mitigation measures. We received a 45-year FERC operating license for Cabinet Gorge and Noxon Rapids in March 2001 that incorporates a comprehensive settlement agreement. The restoration of native salmonid fish, particularly bull trout, is a key part of the agreement. The result is a collaborative bull trout recovery program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana on the lower Clark Fork River, consistent with requirements of the FERC license. See "Hydroelectric Licensing" for further information.

AIR QUALITY — We must be in compliance with requirements under the Clean Air Act (CAA) and Clean Air Act Amendments (CAAA) in operating our thermal generating plants. We continue to monitor legislative developments at the state and national levels for potential further restrictions on sulfur dioxide, nitrogen oxide and carbon dioxide, as well as other greenhouse gas and mercury emissions. Compliance with new and proposed requirements and possible additional legislation or regulations will result in increases to capital expenditures and operating expenses for expanded emission controls at the Company's thermal generating facilities.

The most significant impacts on us, related to the CAA and the 1990 CAAA, pertain to Colstrip, which is a "Phase II" coal-fired plant for sulfur dioxide (SO_2) under the CAAA. However, we do not expect Colstrip to be required to implement any additional SO_2 mitigation in the foreseeable future in order to continue operations. Our other thermal projects are subject to various CAAA standards. Every five years each of the other thermal projects requires an updated operating permit (known as a Title V permit), which addresses, among other things, the compliance of the plant with the CAAA. The operating permit for the Rathdrum CT was renewed in 2006 (expires in 2011) and the operating permit for the Kettle Falls GS was renewed in 2007 (expires in 2012). Coyote Springs 2 was issued a renewed Title V permit in 2008 that expires in 2013. Boulder Park and the Northeast CT do not require a Title V permit based on their limited output and instead each has a synthetic minor permit that does not expire.

In 2006, the Montana Department of Environmental Quality (Montana DEQ) adopted final rules for the control of mercury emissions from coal-fired plants. The new rules set strict mercury emission limits by 2010, and put in place a recurring ten-year review process to ensure facilities are keeping pace with advancing technology in mercury emission control. The rules also provide for temporary alternate emission limits provided certain provisions are met, and they allocate mercury emission credits in a manner that rewards the cleanest facilities. The Company, along with the other owners of Colstrip, completed the first phase of testing on two mercury control technologies. The joint owners of Colstrip believe, based upon current results, that the plant will be able to comply with the Montana law without utilizing the temporary alternate emission limit provision. Current estimates indicate that our share of installation capital costs will be $1.4 million and annual operating costs will increase by $1.5 million (began in late-2009). We will continue to seek recovery, through the ratemaking process, of the costs to comply with various air quality requirements.

WATER QUALITY — See "Clark Fork Settlement Agreement" in "Note 24 of the Notes to Consolidated Financial Statements" regarding dissolved atmospheric gas levels that exceed state of Idaho and federal water quality standards downstream of Cabinet Gorge. See "Spokane River Licensing" in "Note 24 of the Notes to Consolidated Financial Statements" for the Clean Water Act certifications for our licensing of the Spokane River Project.

GLOBAL CLIMATE CHANGES — Rising concerns about long-term global climate changes could have a significant effect on our business. We continue to monitor and evaluate the possible adoption of national, regional, or state requirements related to global climate changes. These requirements could result in significant costs for us to comply with restrictions on carbon dioxide and other greenhouse gas emissions. Such requirements could also preclude us from developing certain types of generating plants or entering into new contracts for the output from generating plants that do not meet these requirements. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Environmental Issues and Other Contingencies" for further information.

OTHER ENVIRONMENTAL ISSUES — See "Colstrip Generating Project Complaint," "Harbor Oil Inc. Site," and "Aluminum Recycling Site" in "Note 24 of the Notes to Consolidated Financial Statements" for information on additional environmental issues.

AVISTA UTILITIES OPERATING STATISTICS

Avista Corporation

Years Ended December 31,

	2009	2008	2007
Electric Operations:			
Electric Operating Revenues (Dollars in Thousands):			
Residential	$ 315,649	$ 279,641	$ 251,357
Commercial	273,954	247,714	224,179
Industrial	107,741	101,785	95,207
Public street and highway lighting	6,607	5,962	5,517
Total retail	703,951	635,102	576,260
Wholesale	88,414	141,744	105,729
Sales of fuel	32,992	44,695	12,910
Other	15,426	16,916	16,231
Total electric operating revenues	$ 840,783	$ 838,457	$ 711,130
Electric Energy Sales (Thousands of MWhs):			
Residential	3,791	3,744	3,670
Commercial	3,177	3,188	3,132
Industrial	1,948	2,059	2,084
Public street and highway lighting	26	26	26
Total retail	8,942	9,017	8,912
Wholesale	2,354	1,964	1,594
Total electric energy sales	11,296	10,981	10,506
Electric Energy Resources (Thousands of MWhs):			
Hydro generation (from Company facilities)	3,766	3,851	3,689
Thermal generation (from Company facilities)	3,097	3,693	3,640
Purchased power — hydro generation from long-term contracts with PUDs	839	833	861
Purchased power — wholesale	4,152	3,253	2,959
Power exchanges	(18)	(17)	(18)
Total power resources	11,836	11,613	11,131
Energy losses and Company use	(540)	(632)	(625)
Total energy resources (net of losses)	11,296	10,981	10,506
Number Of Electric Retail Customers (Average for Period):			
Residential	313,884	311,381	306,737
Commercial	39,276	39,075	38,488
Industrial	1,394	1,388	1,378
Public street and highway lighting	444	434	426
Total electric retail customers	354,998	352,278	347,029
Electric Residential Service Averages:			
Annual use per customer (KWh)	12,079	12,023	11,965
Revenue per KWh (in cents)	8.33	7.47	6.85
Annual revenue per customer	$ 1,005.62	$ 898.07	$ 819.45
Electric Average Hourly Load (aMW)	1,082	1,102	1,089

Avista Corporation

Years Ended December 31,

	2009	2008	2007
Electric Operations (continued):			
Resource Availability at time of system peak (MW):			
Total requirements (winter)			
Retail native load	1,763	1,821	1,685
Wholesale obligations	608	562	367
Total requirements (winter)	2,371	2,383	2,052
Total resource availability (winter)	2,514	2,480	2,302
Total requirements (summer)			
Retail native load	1,522	1,602	1,631
Wholesale obligations	685	431	381
Total requirements (summer)	2,207	2,033	2,012
Total resource availability (summer)	2,499	2,250	2,434
Cooling Degree Days: (1)			
Spokane, WA			
Actual	589	478	576
30-year average	394	394	394
% of average	149%	121%	146%

(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 Corporation

Years Ended December 31,

	2009	2008	2007
Natural Gas Operations:			
Natural Gas Operating Revenues (Dollars in Thousands):			
Residential	$ 251,022	$ 276,386	$ 264,546
Commercial	135,236	152,147	148,416
Industrial and interruptible	9,945	12,159	11,284
Total retail	396,203	440,692	424,246
Wholesale	143,524	281,668	142,167
Transportation	6,067	6,327	6,638
Other	8,624	5,520	4,182
Total natural gas operating revenues	$ 554,418	$ 734,207	$ 577,233
Therms Delivered (Thousands of Therms):			
Residential	207,979	210,125	195,756
Commercial	126,345	128,224	121,557
Industrial and interruptible	10,918	12,196	10,833
Total retail	345,242	350,545	328,146
Wholesale	397,977	345,916	223,084
Transportation	144,580	148,723	148,765
Interdepartmental and Company use	502	526	438
Total therms delivered	888,301	845,710	700,433
Sources Of Natural Gas Supply (Thousands of Therms):			
Purchases	751,057	710,137	561,277
Storage — injections	(99,330)	(76,491)	(35,228)
Storage — withdrawals	95,183	66,271	28,842
Natural gas for transportation	144,580	148,723	148,765
Distribution system losses	(3,189)	(2,930)	(3,223)
Total natural gas supply	888,301	845,710	700,433
Number Of Natural Gas Retail Customers (Average for Period):			
Residential	280,667	277,892	273,415
Commercial	33,214	32,901	32,327
Industrial and interruptible	300	297	302
Total natural gas retail customers	314,181	311,090	306,044
Natural Gas Residential Service Averages:			
Annual use per customer (therms)	741	756	716
Revenue per therm (in dollars)	$ 1.21	$ 1.32	$ 1.35
Annual revenue per customer	$ 894.37	$ 994.58	$ 967.56
Heating Degree Days: (1)			
Spokane, WA			
Actual	6,976	7,052	6,539
30-year average	6,820	6,820	6,820
% of average	102%	103%	96%
Medford, OR			
Actual	4,485	4,569	4,386
30-year average	4,533	4,533	4,533
% of average	99%	101%	97%

(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).*

ADVANTAGE IQ

Our subsidiary, Advantage IQ provides sustainable utility expense management solutions to multi-site companies across North America to assess and manage utility costs and usage. Advantage IQ'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 this process, Advantage IQ analyzes and audits invoices, then presents consolidated bills on-line, and processes payments for these expenses. Information gathered from invoices, providers and other customer-specific data allows Advantage IQ to provide its clients with in-depth analytical support, real-time reporting and consulting services.

Advantage IQ 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 any claimed or threatened infringement on any of Advantage IQ'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.

The following table presents key statistics for Advantage IQ:

	2009	2008	2007
Customers at year-end	532	537	403
Billed sites at year-end	421,080	417,078	199,088
Dollars of customer bills processed (in billions)	$ 17.4	$ 16.7	$ 12.5

The 2009 and 2008 amounts include customers and sites of Cadence Network, which was acquired by Advantage IQ in July 2008 (see "Note 5 of the Notes to Consolidated Financial Statements").

On August 31, 2009, Advantage IQ acquired substantially all of the assets and liabilities of Ecos Consulting, Inc. (Ecos), a Portland, Oregon-based energy efficiency solutions provider.

OTHER BUSINESSES

In periods prior to 2008, we had a reportable Energy Marketing and Resource Management segment. This segment primarily included the results of Avista Energy. On June 30, 2007, Avista Energy and its subsidiary, Avista Energy Canada, completed the sale of substantially all of their contracts and ongoing operations to Shell Energy, as well as to certain other subsidiaries of Shell Energy. Completion of this transaction effectively ended the majority of the operations of this business segment. Avista Energy Canada provided natural gas services to industrial and commercial customers in British Columbia, Canada.

The historical activities of Avista Energy included trading electricity and natural gas, the optimization of generation assets owned by other entities, long-term electric supply contracts, natural gas storage and electric transmission and natural gas transportation arrangements.

Avista Energy still owns natural gas storage facilities and we expect these assets to eventually be transferred to our utility operations. This business had operating revenues and resource costs through the end of 2009 related to the power purchase agreement for the Lancaster Plant. The rights and obligations related to the power purchase agreement for the Lancaster Plant were conveyed to Avista Corp. (Avista Utilities) in January 2010.

Our other businesses 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 venture capital funds and low income housing, and
- the remaining investment in a previous fuel cell 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 "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — 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 AND PRECIPITATION LEVELS) 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, and
- the cost of power supply.

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 may adversely affect cash flows during periods when we purchase natural gas for retail supply at prices above the amount currently 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 and its 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 are required and the ability to realize net benefits from surplus hydroelectric wholesale sales is reduced.

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.

WE HAVE SIGNIFICANT CAPITAL REQUIREMENTS THAT WE EXPECT TO FUND, IN PART, BY ACCESSING CAPITAL MARKETS. FINANCIAL MARKET CONDITIONS MAY IMPACT OUR RESULTS OF OPERATIONS AND OUR LIQUIDITY.

Deterioration in the financial markets and credit availability and the state of 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. Additionally, we may experience an increase in uncollectible customer accounts and collection times. The consequences of a prolonged recession may include a lower level of economic activity and uncertainty regarding energy prices. A lower level of economic activity might result in a decline in energy consumption, which may adversely affect our revenues and future growth.

The deterioration in the financial markets could also result in significant declines in the market values of assets held by our pension plan (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 $320 million and $75 million committed lines of credit, which are scheduled to expire in April 2011. We cannot predict whether we will have access to credit beyond the expiration date. The line of credit agreements contain 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.

WE ARE DEPENDENT ON OUR ABILITY TO ACCESS LONG-TERM CAPITAL MARKETS.

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.

WE ARE SUBJECT TO COMMODITY PRICE RISK.

A combination of factors exposes our operations to commodity price risks. 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 higher prices in wholesale energy markets. 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.

Even 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 a reasonable return to our shareholders. If regulators grant substantially lower rate increases than our requests in the future, 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 BASE 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 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 for the potential of 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.

DOWNGRADES IN OUR CREDIT RATINGS COULD LIMIT OUR ABILITY TO OBTAIN FINANCING, ADVERSELY AFFECT THE TERMS OF FINANCING AND IMPACT OUR ABILITY TO ACQUIRE ENERGY RESOURCES.

We restored an overall corporate investment grade credit rating with the three major credit rating agencies. Our credit ratings were downgraded during 2001, which resulted in an overall corporate credit rating that was below investment grade. The downgrades were due to liquidity concerns primarily related to the significant amount of purchased power and natural gas costs that we incurred in our utility operations. These downgrades increased our debt service costs. Any future downgrades could limit our ability to access capital markets or obtain other financing on reasonable terms. Future downgrades could also require us to provide letters of credit and/or collateral to lenders and counterparties. In addition, future downgrades could reduce the number of counterparties willing to do business with us.

WE ARE SUBJECT TO VARIOUS OPERATIONAL AND EVENT RISKS THAT ARE COMMON TO 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,
- disruptions to our information systems and other administrative resources required for normal operations,
- weather conditions and natural disasters that can cause physical damage to property, requiring repairs to restore utility service, and
- terrorism and other malicious threats.

WE ARE CURRENTLY THE SUBJECT OF SEVERAL REGULATORY PROCEEDINGS, AND WE ARE NAMED IN MULTIPLE LAWSUITS RELATED TO OUR PARTICIPATION IN WESTERN ENERGY MARKETS AS DISCLOSED IN "NOTE 24 OF THE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS."

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 24 of the Notes to Consolidated Financial Statements" for further information. Any potential refunds or obligations arising from western energy market issues (or any other contingent matters) were retained by Avista Energy as part of its asset sale agreement in June 2007.

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 the FERC and the EPA. 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.

THERE HAS BEEN INCREASING LEGISLATIVE ACTION RELATED TO CONCERNS OVER LONG-TERM GLOBAL CLIMATE CHANGES, WHICH MAY AFFECT OUR OPERATIONAL AND FINANCIAL PERFORMANCE.

We are subject to legislative developments at both the state and national level for the potential of further restrictions on sulfur dioxide, nitrogen oxide, carbon dioxide, as well as other greenhouse gas and mercury emissions. Our operations could be affected by changes in laws and regulations intended to mitigate the risk of global climate changes, including restrictions on the operation of our power generation resources. In particular, a greenhouse gas bill was passed by the legislature in the state of Washington and a bill was approved by the U.S. House of Representatives. There will most likely be continuing activity in the near future.

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, and
- restrict the types of generating plants that can be built.

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 24 of the Notes to Consolidated Financial Statements" for further details of these matters including:

- a potential liability related to 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	83.3
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)	4	265.0	254.6
Post Falls (Spokane)	6	14.8	18.0
Montana:			
Noxon Rapids (Clark Fork)	5	480.6	556.6
Total Hydroelectric		913.6	989.9
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	56.3
Boulder Park	6	24.6	24.0
Idaho:			
Rathdrum CT	2	166.5	149.0
Montana:			
Colstrip Units 3 and 4 (3)	2	233.4	222.0
Oregon:			
Coyote Springs 2	1	287.0	278.3
Total Thermal		831.2	786.5
Total Generation Properties		1,744.8	1,776.4

(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, 2009.

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

ELECTRIC DISTRIBUTION AND TRANSMISSION PLANT

We operate approximately 17,800 miles of primary and secondary electric distribution lines providing service to retail customers. We have an electric transmission system of approximately 660 miles of 230 kV line and 1,500 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 system also includes 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 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 BPA, Grant County PUD, PacifiCorp, NorthWestern Energy and Idaho Power Company. These interconnections serve as points of delivery for power from generating facilities outside of our distribution territory, including:

- Colstrip,
- Coyote Springs 2, and
- Mid-Columbia hydroelectric generating facilities.

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 and Kettle Falls projects. These lines interconnect with the BPA, Chelan County PUD, the Grand Coulee Project Hydroelectric Authority, Grant County PUD, NorthWestern Energy, PacifiCorp, Pend Oreille County PUD and Puget Sound Energy. 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 contract 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, 1,900 miles in Idaho and 2,300 miles in Oregon. The natural gas distribution 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 244.1 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 Energy controls 30.3 million therms of our capacity at Jackson Prairie and in conjunction with the asset sales agreement has assigned this capacity to Shell Energy through April 30, 2011. After that date, it is our intent to transfer this capacity to Avista Utilities for use in utility operations subject to state regulatory approval.

ITEM 3. LEGAL PROCEEDINGS

See "Note 24 of Notes to Consolidated Financial Statements" for information with respect to legal proceedings.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

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. As of January 31, 2010, there were 11,675 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 (Avista Utilities).

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 12, 2010, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.25 per share on the Company's common stock.

For additional information, refer to "Notes 1, 21, 22 and 23 of Notes to Consolidated Financial Statements." For high and low stock prices, as well as dividend information, refer to "Note 28 of Notes to Consolidated Financial Statements."

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,

	2009	2008	2007	2006	2005
Operating Revenues:					
Avista Utilities	$ 1,395,201	$ 1,572,664	$ 1,288,363	$ 1,267,938	$ 1,161,317
Advantage IQ	77,275	59,085	47,255	39,636	31,748
Other	40,089	45,014	82,139	198,737	185,971
Intersegment Eliminations	—	—	—	—	(19,429)
Total	$ 1,512,565	$ 1,676,763	$ 1,417,757	$ 1,506,311	$ 1,359,607
Income (Loss) from Operations (pre-tax):					
Avista Utilities	$ 195,389	$ 174,245	$ 150,053	$ 177,049	$ 165,101
Advantage IQ	11,603	11,297	11,012	10,479	6,973
Other	(6,334)	(631)	(22,636)	12,032	(20,327)
Total	$ 200,658	$ 184,911	$ 138,429	$ 199,560	$ 151,747
Net income	$ 88,648	$ 74,757	$ 38,727	$ 72,941	$ 44,988
Net income attributable to noncontrolling interests	$ (1,577)	$ (1,137)	$ (252)	$ —	$ —
Net Income (Loss) Attributable to Avista Corporation:					
Avista Utilities	$ 86,744	$ 70,032	$ 43,822	$ 57,794	$ 52,299
Advantage IQ	5,329	6,090	6,651	6,255	3,922
Other	(5,002)	(2,502)	(11,998)	8,892	(11,233)
Total	$ 87,071	$ 73,620	$ 38,475	$ 72,941	$ 44,988
Average common shares outstanding, basic	54,694	53,637	52,796	49,162	48,523
Average common shares outstanding, diluted	54,942	54,028	53,263	49,897	48,979
Common shares outstanding at year-end	54,837	54,488	52,909	52,514	48,593
Earnings per Common Share Attributable to Avista Corporation:					
Diluted	$ 1.58	$ 1.36	$ 0.72	$ 1.46	$ 0.92
Basic	$ 1.59	$ 1.37	$ 0.73	$ 1.48	$ 0.93
Dividends paid per common share	$ 0.810	$ 0.690	$ 0.595	$ 0.570	$ 0.545
Book value per common share at year-end	$ 19.17	$ 18.30	$ 17.27	$ 17.41	$ 15.82
Total Assets at Year-End:					
Avista Utilities	$ 3,400,384	$ 3,434,844	$ 3,009,499	$ 2,895,883	$ 2,838,154
Advantage IQ	143,060	125,911	108,929	100,431	46,094
Other	63,515	69,992	71,369	1,060,194	2,064,246
Total	$ 3,606,959	$ 3,630,747	$ 3,189,797	$ 4,056,508	$ 4,948,494
Long-Term Debt (including current portion)	$ 1,071,338	$ 826,465	$ 948,833	$ 976,459	$ 1,029,514
Long-Term Debt to Affiliated Trusts	51,547	113,403	113,403	113,403	113,403
Preferred Stock Subject to Mandatory Redemption	—	—	—	26,250	28,000
Total Avista Corporation Stockholders' Equity	$ 1,051,287	$ 996,883	$ 913,966	$ 914,525	$ 768,849
Ratio of Earnings to Fixed Charges (1)	2.95	2.43	1.67	2.14	1.73

(1) See Exhibit 12 for computations.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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 and precipitation levels) and their effects on energy demand and electric generation, including the effect of precipitation and temperatures on the availability of hydroelectric resources, the effect of temperatures on customer demand, and similar impacts on supply and demand in the wholesale energy markets;
- the effect of state and federal regulatory decisions on our ability to recover costs and earn a reasonable return including, but not limited to, the disallowance of costs and investments, and delay in the recovery of capital investments and operating costs;
- changes in wholesale energy prices that can affect, among other things, the cash requirements to purchase electricity and natural gas, the value received for sales in the wholesale energy market, the necessity to request changes in rates that are subject to regulatory approval, collateral required of us by counterparties on wholesale energy transactions and credit risk to us from such transactions, and the market value of derivative assets and liabilities;
- global financial and economic conditions (including the impact on capital markets) and their effect on our ability to obtain funding at a reasonable cost;
- our ability to obtain financing through the issuance of debt and/or equity securities, which can be affected by various factors including our credit ratings, interest rates and other capital market conditions;
- economic conditions in our service areas, including the effect on the demand for, and customers' payment for, our utility services;
- the potential effects of legislation or administrative rulemaking, including the possible adoption of national or state laws requiring 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;
- 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 or other malicious acts, particularly for our utility assets;
- delays or changes in construction costs, and our ability to obtain required permits and materials for present or prospective facilities;
- changes in the long-term climate of the Pacific Northwest, which can affect, among other things, customer demand patterns and the volume and timing of streamflows to our hydroelectric resources;
- changes in industrial, commercial and residential growth and demographic patterns in our service territory or the loss of significant customers;
- the loss of key suppliers for materials or services;
- default or nonperformance on the part of any parties from which we purchase and/or sell capacity or energy;
- deterioration in the creditworthiness of our customers and counterparties;
- the effect of any potential decline in our credit ratings, including impeded access to capital markets, higher interest costs, and certain covenants with ratings triggers in our financing arrangements and wholesale energy contracts;
- increasing health care costs and the resulting effect on health insurance provided to our employees and retirees;

- increasing costs of insurance, more restricted coverage terms and our ability to obtain insurance;
- work force issues, including changes in collective bargaining unit agreements, strikes, work stoppages or the loss of key executives, availability of workers in a variety of skill areas, and our ability to recruit and retain employees;
- the potential effects of negative publicity regarding business practices, whether true or not, which could result in, among other things, costly litigation and a decline in our common stock price;
- changes in technologies, possibly making some of the current technology obsolete;
- changes in tax rates and/or policies; and
- changes in our strategic business plans, which may be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses.

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

In this Form 10-K, we discuss our credit ratings. 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 independently of all other ratings.

The following discussion and analysis is provided for the consolidated financial condition and results of operations of Avista Corp. and its subsidiaries and should be read along with the consolidated financial statements.

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.
- **ADVANTAGE IQ** — an indirect subsidiary of Avista Corp. (approximately 74 percent owned as of December 31, 2009) that provides sustainable utility expense management solutions to its customers that are generally multi-site companies across North America to assess and manage utility costs and usage. Advantage IQ's primary product lines include processing, payment and auditing of energy, telecom, waste, water/sewer and lease bills, as well as strategic management services.

We have other businesses, including sheet metal fabrication, venture fund investments and real estate investments, as well as certain natural gas storage facilities held by Avista Energy. These activities do not represent a reportable business segment and are conducted by various indirect subsidiaries of Avista Corp., including Advanced Manufacturing and Development (AM&D), doing business as METALfx.

The following table presents net income (loss) attributable to Avista Corporation for each of our business segments (and the other businesses) for the year ended December 31 (dollars in thousands):

	2009	2008	2007
Avista Utilities	$ 86,744	$ 70,032	$ 43,822
Advantage IQ	5,329	6,090	6,651
Other	(5,002)	(2,502)	(11,998)
Net income attributable to Avista Corporation	$ 87,071	$ 73,620	$ 38,475

EXECUTIVE LEVEL SUMMARY

OVERALL

Our operating results and cash flows are primarily from:

- regulated utility operations (Avista Utilities), and
- facility information and cost management services for multi-site customers (Advantage IQ).

Our net income attributable to Avista Corporation was $87.1 million for 2009, an increase from $73.6 million for 2008. This increase was primarily due to increased earnings at Avista Utilities (primarily due to the implementation of general rate increases in Washington and Idaho) as well as a decrease in interest expense. This was partially offset by a decrease in earnings at Advantage IQ and an increase in the net loss from the other businesses.

In late 2007, early 2008, and early 2009, Moody's Investors Service, Standard & Poor's and Fitch Ratings, Inc. upgraded our credit ratings, which resulted in an investment grade rating for our senior unsecured debt and corporate rating from each of these rating agencies. The upgrades reflected several steps taken over the past few years to lower our business risk profile and improve financial metrics. See further discussion at "Credit Ratings." It is important to note that we are at the lower end of the investment grade category. We are working to continuously strengthen our credit ratings by improving earnings and operating cash flows, controlling costs and reducing our debt ratio.

Employment has declined throughout our service area due to cutbacks in the construction, forest products, mining and manufacturing sectors. Non-farm employment contraction for December 2009 as compared to December 2008 was 1.8 percent in Spokane, Washington, 4.6 percent in Medford, Oregon and 3.9 percent in Coeur d'Alene, Idaho, compared to the national average decline of 3.0 percent. Unemployment rates were higher for December 2009 than December 2008 in our service areas. Unemployment rates for December 2009 were 9.3 percent in Spokane, Washington, 10.6 percent in Coeur d'Alene, Idaho and 11.7 percent in Medford, Oregon, compared to the national average of 10.0 percent. The housing markets in Coeur d'Alene, Idaho and Medford, Oregon have had a higher foreclosure rate than the national average; the 2009 annual foreclosure rate was 2.6 percent in Kootenai County (the county that includes Coeur d'Alene, Idaho), and 3.1 percent in Jackson County (the county that includes Medford, Oregon) compared to the national foreclosure rate of 2.2 percent; the housing market in Spokane County remains stable with a foreclosure rate of 0.9 percent.

AVISTA UTILITIES

Avista Utilities is our most significant business segment. Our utility operating and 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 fair 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.

Our utility net income was $86.7 million for 2009, an increase from $70.0 million for 2008 partially due to an increase in gross margin (operating revenues less resource costs). The increase in gross margin was primarily due to the implementation of the general rate increases in Washington and Idaho. In addition, our power supply costs were less than the amount included in retail rates in Washington. This was due to lower wholesale electric and natural gas fuel prices, partially offset by below normal hydroelectric generation and the negative impact from the extended outage at the Colstrip plant (with one of the units out of service from May 2009 until November 2009). This resulted in a benefit of $3.0 million under the Energy Recovery Mechanism (ERM) in Washington for 2009 compared to an expense of $7.4 million in 2008. The increase in net income was also due to a decrease in interest expense. These positive impacts on net income were partially offset by an increase in other operating expenses, depreciation and amortization and taxes other than income taxes.

We are continuing to invest in generation, transmission and distribution systems to enhance service reliability for our customers. Utility capital expenditures were $205.4 million for 2009. We expect utility capital expenditures to be over $210 million for 2010. These estimates of capital expenditures are subject to continuing review and adjustment and do not include costs for projects associated with stimulus funding (see discussion at "Avista Utilities Capital Expenditures").

ADVANTAGE IQ

Advantage IQ had net income of $5.3 million for 2009, a decrease from $6.1 million for 2008. The decrease for 2009 as compared to 2008 was primarily due to lower short-term interest rates (which decreases interest revenue), the decrease in our ownership percentage in the business in connection with the acquisition of Cadence Network effective July 2, 2008 and increased amortization of intangible assets (related to the Cadence and Ecos acquisitions — refer to the Cadence and Ecos discussions below). During 2009, we experienced slower internal growth at Advantage IQ than was originally expected, as some of its clients are experiencing bankruptcies and store closures in these difficult economic times. Additionally, interest revenue was lower in 2009 due to the historic low short-term interest rate environment that we are experiencing, which is expected to continue in 2010. The decrease in interest revenue was offset by other customer billing services, which increased operating revenues for 2009 as compared to 2008.

On August 31, 2009, Advantage IQ 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 Advantage IQ's committed credit agreement. Under the terms of the transaction, the assets and liabilities of Ecos were acquired by a wholly owned subsidiary of Advantage IQ.

Effective July 2, 2008, Advantage IQ acquired Cadence Network, a Cincinnati, Ohio-based energy and expense management company. As consideration, the owners of Cadence Network received a 25 percent ownership interest in Advantage IQ. The acquisition of Cadence Network was funded with the issuance of Advantage IQ common stock, which is subject to redemption. Under the transaction agreement, the previous owners of Cadence Network can exercise a right to have their shares of Advantage IQ stock redeemed during July 2011 or July 2012 if Advantage IQ is not liquidated through either an initial public offering or sale of the business to a third party. Their redemption rights expire July 31, 2012. The redemption price would be determined based on the fair market value of Advantage IQ at the time of the redemption election as determined by certain independent parties.

We would like to have a market determined valuation of our investment in Advantage IQ within the next four years. The potential valuation of Advantage IQ 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 Advantage IQ. There can be no assurance that we will be able to complete such a transaction.

OTHER BUSINESSES

The net loss for these operations was $5.0 million for 2009 compared to a net loss of $2.5 million for 2008. Contributing to the net loss attributable to Avista Corporation for 2009 was the impairment of a commercial building of $3.0 million, losses on long-term venture fund investments of $0.8 million (compared to losses of $1.4 million in 2008) and increased litigation costs related to the remaining contracts and previous operations of Avista Energy.

LIQUIDITY AND CAPITAL RESOURCES

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

We have a committed line of credit in the total amount of $320.0 million with an expiration date of April 5, 2011. We had $87.0 million of cash borrowings and $28.4 million in letters of credit outstanding as of December 31, 2009, under our $320.0 million committed line of credit.

In November 2009, we entered into a new committed line of credit in the total amount of $75.0 million with an expiration date of April 5, 2011. The new committed line of credit replaced a $200.0 million committed line of credit that expired in November 2009. We had no borrowings outstanding as of December 31, 2009, under our $75.0 million committed line of credit. We reduced the facility based on our forecasted liquidity needs.

In March 2009, we amended our accounts receivable sales facility to extend the termination date to March 2010. We expect to renew this facility before the March 2010 expiration. Under this facility, we can sell without recourse, on a revolving basis, up to $85.0 million of accounts receivable. Based upon calculations of our eligible accounts receivable under this agreement, we had the ability to sell up to $85.0 million as of December 31, 2009. There were not any accounts receivable sold under this facility as of December 31, 2009.

As of December 31, 2009, we had a combined $364.6 million of available liquidity under our $320.0 million committed line of credit, $75.0 million committed line of credit, and $85.0 million revolving accounts receivable sales facility.

In September 2009, we issued $250.0 million of 5.125 percent First Mortgage Bonds due in 2022. The net proceeds from the issuance of $249.4 million (net of discounts and before Avista Corp.'s expenses) were used to retire variable rate short-term borrowings outstanding under our $320.0 million committed line of credit, and for general corporate purposes. In conjunction with the issuance of long-term debt, we cash settled interest rate swap agreements and received a total of $10.8 million.

In April 2009, we redeemed the total amount outstanding ($61.9 million) of our Junior Subordinated Debt Securities held by AVA Capital Trust III (Long-term Debt to Affiliated Trusts). Concurrently, AVA Capital Trust III redeemed all of the Preferred Trust Securities issued to third parties ($60.0 million) and all of the Common Trust Securities issued to us ($1.9 million). The net redemption of $60.0 million was funded by borrowings under our $320.0 million committed line of credit agreement.

In December 2009, we purchased $17.0 million of our Pollution Control Bonds. We are planning, subject to market conditions, to refund these bonds in 2010 along with $66.7 million of our Pollution Control Bonds we purchased in December 2008.

In addition to the refunding of $83.7 million of our Pollution Control Bonds, we are planning to issue up to $45 million of common stock in 2010 in order to maintain our capital structure at an appropriate level for our business. After considering the refunding of our Pollution Control Bonds and issuances of common stock during 2010, we expect net cash flows from operating activities and our committed line of credit agreements (total of $395.0 million) to provide adequate resources to fund:

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

In December 2009, we entered into an amended and restated sales agency agreement with a sales agent to issue up to 1.25 million shares of our common stock from time to time. We originally entered into a sales agency agreement to issue up to 2 million shares of our common stock in December 2006. In 2008, we issued 750,000 shares of our common stock under this sales agency agreement. We did not issue any common stock under this agreement in 2009.

Due to market conditions and the decline in the fair value of pension plan assets in 2008, we contributed $48 million to the pension plan in 2009 as compared to the $28 million we contributed in 2008. In 2009, the fair value of pension plan assets increased. We expect that our contribution for 2010 will be $21 million. The determination of pension plan contributions in 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 projected benefit obligation).

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
- more closely align earned returns with those allowed by regulators.

With regards to the timing and plans for future filings, the assessment of our need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include, but are not limited to, in-service dates of major capital investments and the timing of changes in major revenue and expense items. We are planning to file general rate cases in Washington and Idaho by the end of the first quarter of 2010 and expect to file a general rate case in Oregon by the end of the second quarter of 2010 to more closely align earned returns with those authorized.

The following is a summary of our authorized rates of return in each jurisdiction:

Jurisdiction and service	Implementation Date	Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
Washington electric and natural gas	January 2010	8.25%	10.2%	46.5%
Idaho electric and natural gas	August 2009	8.55%	10.5%	50.0%
Oregon natural gas	November 2009	8.19%	10.1%	50.0%

WASHINGTON GENERAL RATE CASES

In September 2008, we entered into a settlement stipulation in our general rate case that was filed with the WUTC in March 2008. This settlement stipulation was approved by the WUTC in December 2008. The new electric and natural gas rates became effective on January 1, 2009. As agreed to in the settlement, base electric rates for our Washington customers increased by an average of 9.1 percent, which was designed to increase annual revenues by $32.5 million. Base natural gas rates for our Washington customers increased by an average of 2.4 percent, which was designed to increase annual revenues by $4.8 million.

On January 27, 2009, the Public Counsel Section of the Washington Attorney General's Office (Public Counsel) filed a Petition for Judicial Review (in Thurston County Superior Court) of the WUTC's December 2008 order approving our multiparty settlement. Public Counsel raised a number of issues that were previously argued before the WUTC. These included whether the recovery of settlement costs associated with resolving a dispute with the Coeur d'Alene Tribe would constitute illegal "retroactive ratemaking" (the Washington portion of these costs was $25.2 million). Public Counsel also questioned whether the WUTC's decision to entertain supplemental testimony to update our filing for power supply costs during the course of the proceedings was appropriate. Finally, Public Counsel argued that the settlement improperly included advertising costs, dues and donations, and certain other expenses. The appeal itself did not prevent the new rates from going into effect.

On December 18, 2009, the Thurston County Superior Court affirmed the decision of the WUTC and rejected the arguments of Public Counsel, with the exception of disallowing $0.1 million of miscellaneous expenses, including charitable donations. Public Counsel has until March 4, 2010 to further appeal the WUTC's decision.

On December 22, 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 is 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 is designed to increase annual revenues by $0.6 million. The new electric and natural gas rates became effective on January 1, 2010.

Following the execution of a partial settlement stipulation in September 2009, we revised our electric rate increase request downward from $69.8 million to $37.5 million, primarily due to the decline in the wholesale prices of electricity and natural gas. We also reduced our natural gas request from $4.9 million to $2.8 million. Under the partial settlement stipulation, we reached agreement with the other settling parties on issues in the areas of cost of capital, power supply, rate spread and rate design, and funding under the Low-Income Ratepayer Assistance Program. The WUTC approved this partial settlement stipulation in its order on December 22, 2009.

The WUTC did not allow us to include the costs associated with the power purchase agreement for the Lancaster Plant in rates, indicating we did not demonstrate compliance with certain requirements necessary for immediate inclusion in rates. However, the WUTC directed us to file to defer costs associated with the Lancaster Plant, with a carrying charge, for potential recovery in a future rate proceeding if we demonstrate that we have satisfied these requirements. Our proposed deferred accounting treatment for the net costs associated with the Lancaster Plant was approved by the WUTC in February 2010. The net costs associated with the power purchase agreement for the Lancaster Plant account for approximately half of the difference between our revised electric rate increase request of $37.5 million and the $12.1 million increase approved by the WUTC.

The WUTC also did not allow for certain pro forma future capital additions to rate base, as well as certain increases in labor costs, tree trimming costs and information systems costs. These costs account for the majority of the remaining difference between our revised electric rate increase request and the amount approved by the WUTC.

The partial settlement stipulation (as approved by the WUTC on December 22, 2009) is based on an overall rate of return of 8.25 percent with a common equity ratio of 46.5 percent and a 10.2 percent return on equity. Our original request was based on a proposed overall rate of return of 8.68 percent with a common equity ratio of 47.5 percent and an 11.0 percent return on equity.

IDAHO GENERAL RATE CASES

In August 2008, we entered into an all-party settlement stipulation in our electric and natural gas general rate cases that were filed with the IPUC in April 2008. This settlement stipulation was approved by the IPUC in September 2008. The new electric and natural gas rates became effective on October 1, 2008. As agreed to in the settlement, base electric rates for our Idaho customers increased by an average of 12.0 percent, which was designed to increase annual revenues by $23.2 million. Base natural gas rates for our Idaho customers increased by an average of 4.7 percent, which was designed to increase annual revenues by $3.9 million.

In June 2009, we entered into an all-party settlement stipulation in our electric and natural gas general rate cases that were filed with the IPUC in January 2009. This settlement stipulation was approved by the IPUC in July 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. Offsetting the base electric rate increase was an overall 4.2 percent decrease in the Power Cost Adjustment (PCA) surcharge, which was designed to decrease annual PCA revenues by $9.3 million, resulting in a net increase in annual revenues of $3.2 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. Offsetting the natural gas rate increase for residential customers was an equivalent Purchased Gas Adjustment (PGA) decrease of 2.1 percent. Large general services received a PGA decrease of 2.4 percent and interruptible services received a PGA decrease of 2.8 percent. The overall PGA decrease resulted in a $2.0 million decrease in annual PGA revenues, resulting in a net decrease in annual revenues of $0.1 million. The PGAs are designed to pass through changes in natural gas costs to our customers with no change in gross margin or net income.

Our original request was for an electric rate increase of 12.8 percent, which was designed to increase annual revenues by $31.2 million. Offsetting the electric rate increase was a decrease in the PCA surcharge of 5.0 percent, which was designed to decrease annual revenues by $12.3 million. We also requested to increase natural gas rates by an average of 3.0 percent, which was designed to increase annual revenues by $2.7 million.

OREGON GENERAL RATE CASES

As approved by the OPUC in March 2008, natural gas rates for our Oregon customers increased 0.4 percent effective April 1, 2008 (designed to increase annual revenues by $0.5 million) and increased an additional 1.1 percent effective November 1, 2008 (designed to increase annual revenues by an additional $1.4 million).

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 our June 2009 general rate case filing, we requested a natural gas rate increase of 11.6 percent, designed to increase annual natural gas service revenues by $14.2 million. As part of the settlement agreement, we agreed to refund a total of $2.4 million to our Oregon customers related to Oregon Senate Bill 408 (see further discussion below).

PURCHASED GAS ADJUSTMENTS

Effective November 1, 2009, natural gas rates decreased 22 percent in Oregon, 26 percent in Washington and 23 percent in Idaho. PGAs are designed to pass through changes in natural gas costs to our customers with no change in gross margin (operating revenues less resource costs) or net income. In Oregon, we absorb (gain or loss) 10 percent of the difference between actual and projected gas costs for supply that is not hedged. Total net deferred natural gas costs were a liability of $40.0 million as of December 31, 2009, an increase from $18.6 million as of December 31, 2008. The liability at December 31, 2009 is being refunded to customers through the PGAs implemented in November 2009.

OREGON SENATE BILL 408

The OPUC established rules in September 2007 related to Oregon Senate Bill 408 (OSB 408), which was enacted into law in 2005. These rules direct the utility to establish an automatic adjustment clause to account for the difference between income taxes collected in rates and taxes paid to units of government, net of adjustments, when that difference exceeds $100,000. The automatic adjustment clause may result in either rate increases or rate decreases.

In October 2009, the OPUC approved a settlement stipulation in our general rate case that also resolved the refund liability for the 2007 tax report. The approved settlement provided for a refund of $2.4 million, including interest, over a two-month period, November and December of 2009. This refund was approximately equal to the new revenue from the general rate increase for this period.

In October 2009, we filed the tax report for 2008 showing taxes paid to be less than taxes collected by $0.9 million before interest. In January 2010, we filed an all-party settlement with the OPUC for this amount. We expect an order from the OPUC on the final level of refund by April 2010. We recorded a potential refund liability for the 2009 tax report of $0.8 million.

NATURAL GAS DECOUPLING

In January 2007, the WUTC approved the implementation of a natural gas decoupling mechanism as a pilot for a two and one-half-year period. The decoupling mechanism is designed to recover a portion of lost margin resulting from lower usage by Washington residential and small commercial customers primarily due to conservation. However, the mechanism does not provide rate adjustments related to abnormal weather. As part of the general rate case order in December 2009, the WUTC approved continuation of the natural gas decoupling mechanism on a permanent basis, with certain modifications. Beginning July 2009, we can defer 45 percent of the lost margin associated with lower customer usage, as compared to a deferral of 90 percent during the pilot period. In the fall of each year, we can file to recover the deferred amount accumulated over the most recent July-June period if our energy efficiency therm savings meet certain pre-established targets associated with our natural gas demand side management programs. If per-customer therm usage (weather-normalized) during a July-June period were to increase instead of decrease, it may result in a refund to customers of 45 percent of the margin associated with higher customer usage.

POWER COST DEFERRALS AND RECOVERY MECHANISMS

The ERM is an accounting method used to track certain differences between actual power supply costs, net of the margin on wholesale sales, and the amount included in base retail rates for our Washington customers. In periods where we are a net seller of wholesale power, market prices lower than the prices included in rates negatively impact the ERM. In periods where we are a net purchaser, market prices lower than the amount included in retail rates have a beneficial impact under the ERM.

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.

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

The following is a summary of the ERM:

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

Under the ERM, we make an annual filing on or before April 1 of each year to provide the opportunity for the WUTC staff and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. 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 January 1, 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.

In February 2010, the WUTC approved our request to eliminate the existing ERM surcharge. The surcharge was eliminated as the previous balance of deferred power costs has been substantially recovered. This will result in an overall rate reduction of 7 percent for our Washington customers with no impact on our income from operations or net income.

A provision of our ERM requires that in the case of a major plant outage (below 70 percent availability), there may be a disallowance of fixed costs during the outage period if the outage resulted from imprudent actions, or if actual fixed costs are below the level used to calculate base rates. During scheduled maintenance in March 2009, turbines in unit 4 of Colstrip, of which we are a 15 percent owner, were found to be in need of repair. These repairs extended the planned outage from May 2009 until November 2009. We believe the outage was not due to imprudent actions and we expect there will not be a reduction in fixed costs for the plant outage.

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 costs deferred during the preceding July-June twelve-month period. The PCA rate surcharge was 0.61 cents per KWh for the period October 1, 2008 through September 30, 2009. However, the surcharge rate was lowered to 0.344 cents per KWh on August 1, 2009 to help mitigate the impact of the general rate increase that was also effective on that date. The surcharge rate is expected to remain in place until October 1, 2010, when it will be replaced by a new rate that will be proposed as part of the PCA report for the period July 1, 2009 through June 30, 2010.

The following table shows activity in deferred power costs for Washington and Idaho during 2008 and 2009 (dollars in thousands):

	Washington	Idaho	Total
Deferred power costs as of December 31, 2007	$ 58,524	$ 21,163	$ 79,687
Activity from January 1 — December 31, 2008:			
Power costs deferred	7,049	10,029	17,078
Interest and other net additions	2,231	1,153	3,384
Recovery of deferred power costs through retail rates	(30,852)	(11,690)	(42,542)
Deferred power costs as of December 31, 2008	36,952	20,655	57,607
Activity from January 1 — December 31, 2009:			
Power costs deferred	—	17,985	17,985
Interest and other net additions	879	388	1,267
Recovery of deferred power costs through retail rates	(31,567)	(17,521)	(49,088)
Deferred power costs as of December 31, 2009	$ 6,264	$ 21,507	$ 27,771

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, Advantage IQ and the other businesses) that follow this section.

2009 COMPARED TO 2008

Utility revenues decreased $177.5 million to $1,395.2 million due to decreased natural gas revenues of $179.8 million, partially offset by increased electric revenues of $2.3 million. The decrease in natural gas revenues was primarily the result of decreased wholesale revenues of $138.1 million (due to decreased prices, offset by increased volumes) and retail natural gas revenues of $44.5 million (primarily due to decreased prices and partially due to decreased volumes). The increase in electric revenues was primarily due to increased retail revenues of $68.8 million (primarily due to the Washington general rate increase implemented on January 1, 2009 and the Idaho general rate increases implemented on October 1, 2008 and August 1, 2009), partially offset by decreased wholesale revenues of $53.3 million (due to a decrease in prices, partially offset by an increase in volumes) and sales of fuel of $11.7 million.

Non-utility energy marketing and trading revenues decreased $0.8 million to $24.4 million. These revenues primarily represent payments for the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of this agreement were conveyed to Shell Energy through the end of 2009. These rights and obligations were conveyed to our utility operations in January 2010.

Other non-utility revenues increased $14.1 million to $92.9 million as a result of an increase in revenues from Advantage IQ of $18.2 million primarily due to the acquisition of Cadence Network in the third quarter of 2008 and Ecos in the third quarter of 2009, as well as other customer billing services. These increases in revenues from Advantage IQ were partially offset by a decrease in interest earnings on funds held for customers (due to lower interest rates). The increase in revenues at Advantage IQ was partially offset by decreased revenues from our other businesses of $4.1 million, primarily due to decreased sales at AM&D.

Utility resource costs decreased $232.5 million due to decreases in natural gas resource costs of $186.1 million and electric resource costs of $46.3 million. The decrease in natural gas resource costs primarily reflects a decrease in the price of natural gas purchases. The decrease in electric resource costs was primarily due to a decrease in fuel costs (due to a decrease in thermal generation and natural gas fuel prices).

Utility other operating expenses increased $23.4 million primarily due to an $8.9 million increase in electric generation operating and maintenance expenses, a $4.3 million increase in natural gas distribution and service costs, as well as a $10.7 million increase in pension and other benefit costs.

Utility depreciation and amortization increased $5.9 million primarily due to additions to utility plant.

Utility taxes other than income taxes increased $4.5 million due to increased revenue related taxes and increased property taxes.

Non-utility resource costs decreased $0.1 million. These costs primarily represent payments for the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of this agreement were conveyed to Shell Energy through the end of 2009. These rights and obligations were conveyed to our utility operations in January 2010.

The net change in other non-utility operating expenses was an increase of $17.6 million due to an increase of $16.6 million for Advantage IQ primarily due to the acquisition of Cadence Network in the third quarter of 2008 and the acquisition of Ecos in the third quarter of 2009. The increase was also partially due to an impairment of a commercial building of $3.0 million in the other businesses. These increases were partially offset by decreased operating expenses from AM&D.

Interest expense decreased $8.4 million due to the effect of long-term debt maturities and redemptions during 2008, which were funded primarily with proceeds from the issuance of long-term debt as well as borrowings under our $320.0 million committed line of credit at lower interest rates. The decrease was also partially due to interest expense of $1.4 million related to an income tax settlement recorded in the third quarter of 2008.

Interest expense to affiliated trusts decreased $4.2 million due to the redemption of $61.9 million of long-term debt due to affiliated trusts in April 2009 and a decrease in the variable interest rate.

Capitalized interest decreased $4.1 million primarily due to a decrease in the effective borrowing rate used to compute capitalized interest, as the average balance outstanding under our committed line of credit was significantly higher in 2009 as compared to 2008.

Other income-net decreased $9.6 million due to a decrease in interest income (primarily due to $5.7 million of interest income recorded on the Internal Revenue Service (IRS) settlement agreement in the third quarter of 2008). The decrease was also due to a decrease in equity-related AFUDC.

Income taxes increased $0.7 million and our effective tax rate was 34.3 percent for 2009 compared to 37.9 percent for 2008. The decrease in our effective tax rate was primarily due to adjustments related to IRS audits and adjustments for the 2008 filed federal tax return. In total, these adjustments (recorded in the third quarter of 2009) had a favorable impact to recorded income tax expense of $3.2 million (Avista Utilities).

2008 COMPARED TO 2007

Utility revenues increased $284.3 million to $1,572.7 million as a result of increases in natural gas revenues of $157.0 million and electric revenues of $127.3 million. The increase in natural gas revenues was primarily the result of increased wholesale revenues (due to increased prices and volumes) of $139.5 million and retail natural gas revenues (due to increased volumes) of $16.4 million. The increase in electric revenues was primarily due to increased retail revenues (primarily due to the Washington general rate increase implemented on January 1, 2008 and the Idaho general rate increase implemented on October 1, 2008) of $58.8 million, wholesale revenues of $36.0 million and sales of fuel of $31.8 million.

Non-utility energy marketing and trading revenues decreased $36.3 million to $25.2 million. This category of revenues decreased significantly with the sale of substantially all of Avista Energy's contracts and ongoing operations on June 30, 2007.

Other non-utility revenues increased $11.0 million to $78.9 million as a result of an increase in revenues from Advantage IQ of $11.8 million primarily due to customer growth and the acquisition of Cadence Network in the third quarter of 2008, partially offset by a decrease in interest earnings on funds held for customers (due to lower interest rates).

Utility resource costs increased $251.0 million due to increases in natural gas resource costs of $147.9 million and electric resource costs of $103.1 million. The increase in natural gas resource costs primarily reflects an increase in the volume and price of natural gas purchases and increased amortization of deferred natural gas costs. The increase in electric resource costs reflects an increase in base resource costs as set forth in the Washington general rate case implemented on January 1, 2008 and the Idaho general rate case implemented on October 1, 2008, as well as higher purchased power and fuel costs.

Utility other operating expenses increased $7.8 million primarily due to a $4.0 million increase in electric generation operating and maintenance expenses, as well as a $3.4 million increase in electric distribution expenses. This was partially offset by the impairment of a turbine in the third quarter of 2007 of $2.3 million.

Utility depreciation and amortization increased $1.8 million primarily due to additions to utility plant.

Non-utility resource costs decreased $45.1 million. This category of expenses decreased significantly with the sale of substantially all of Avista Energy's contracts and ongoing operations on June 30, 2007.

The net change in other non-utility operating expenses was a decrease of $2.7 million due to:

- a decrease of $13.2 million in the other businesses due to the sale of Avista Energy's ongoing operations, partially offset by
- an increase of $10.5 million for Advantage IQ due to expanding operations and the acquisition of Cadence Network in the third quarter of 2008.

Interest expense decreased $5.7 million due to the redemption of all outstanding preferred stock in September 2007 and the effect of long-term debt maturities during 2007 and 2008, which were primarily funded with proceeds from the sale and liquidation of Avista Energy's assets and the issuance of long-term debt at lower interest rates. This was partially offset by interest expense of $1.4 million related to an income tax settlement.

Interest expense to affiliated trusts decreased $1.2 million due to a decrease in the variable interest rate.

Other income-net decreased $0.6 million primarily due to a decrease in interest income of $4.6 million. The decrease in interest income was primarily due to the disposition of Avista Energy's ongoing operations. Also contributing to the decrease were losses on long-term venture fund investments. The net decrease was offset by $5.7 million of interest income recorded on the IRS settlement agreement for the 2001 through 2003 tax years and the resulting refund.

Income taxes increased $21.3 million primarily due to increased income before income taxes. Our effective tax rate was 37.9 percent for 2008 compared to 38.6 percent for 2007.

AVISTA UTILITIES

2009 COMPARED TO 2008

Net income for the utility was $86.7 million for 2009 compared to $70.0 million for 2008. Utility income from operations was $195.4 million for 2009 compared to $174.2 million for 2008. This increase in income from operations was primarily due to increased gross margin (operating revenues less resource costs). This was partially offset by an increase in other utility operating expenses, depreciation and amortization and taxes other than income taxes.

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

	Electric		Natural Gas		Total	
	2009	2008	2009	2008	2009	2008
Operating revenues	$ 840,783	$ 838,457	$ 554,418	$ 734,207	$ 1,395,201	$ 1,572,664
Resource costs	379,058	425,373	420,481	606,616	799,539	1,031,989
Gross margin	$ 461,725	$ 413,084	$ 133,937	$ 127,591	$ 595,662	$ 540,675

Utility operating revenues decreased $177.5 million and utility resource costs decreased $232.5 million, which resulted in an increase of $55.0 million in gross margin. The gross margin on electric sales increased $48.6 million and the gross margin on natural gas sales increased $6.3 million. The increase in our electric and natural gas gross margin was primarily due to the implementation of general rate increases in Washington effective January 1, 2009 and Idaho effective October 1, 2008 and August 1, 2009. We had a benefit of $3.0 million under the ERM in 2009 compared to an expense of $7.4 million in 2008, which increased electric gross margin and income from operations by $10.4 million in 2009 as compared to 2008.

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	
	2009	2008	2009	2008
Residential	$ 315,649	$ 279,641	3,791	3,744
Commercial	273,954	247,714	3,177	3,188
Industrial	107,741	101,785	1,948	2,059
Public street and highway lighting	6,607	5,962	26	26
Total retail	703,951	635,102	8,942	9,017
Wholesale	88,414	141,744	2,354	1,964
Sales of fuel	32,992	44,695	—	—
Other	15,426	16,916	—	—
Total	$ 840,783	$ 838,457	11,296	10,981

Retail electric revenues increased $68.8 million due to an increase in revenue per MWh (increased revenues $74.7 million) primarily due to the Washington general rate increase implemented on January 1, 2009 and the Idaho general rate increases implemented on October 1, 2008 and August 1, 2009, offset by a decrease in total MWhs sold (decreased revenues $5.9 million) primarily due to a decrease in use per customer (commercial and industrial).

Wholesale electric revenues decreased $53.3 million due to a decrease in sales prices (decreased revenues $68.0 million), offset by an increase in sales volumes (increased revenues $14.7 million). The increase in sales volume primarily relates to resource optimization activities.

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market as sales of fuel. Sales of fuel decreased $11.7 million due to a decrease in thermal generation resource optimization activities and lower natural gas prices in 2009 as compared to 2008.

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	
	2009	2008	2009	2008
Residential	$ 251,022	$ 276,386	207,979	210,125
Commercial	135,236	152,147	126,345	128,224
Interruptible	4,709	5,428	5,360	5,758
Industrial	5,236	6,731	5,558	6,438
Total retail	396,203	440,692	345,242	350,545
Wholesale	143,524	281,668	397,977	345,916
Transportation	6,067	6,327	144,580	148,723
Other	8,624	5,520	502	526
Total	$ 554,418	$ 734,207	888,301	845,710

The $44.5 million decrease in retail natural gas revenues was due to a decrease in volumes (decreased revenues $6.1 million), and lower retail rates (decreased revenues $38.4 million). We sold less retail natural gas in 2009 as compared to 2008, primarily due to warmer weather, as well as a decrease in commercial and industrial use per customer. The decrease in retail rates reflects the purchased gas adjustments implemented in 2009 offset by the Washington general rate increase implemented on January 1, 2009 and Idaho general rate increases implemented on October 1, 2008 and August 1, 2009.

The decrease in our wholesale natural gas revenues of $138.1 million was due to a decrease in prices (decreased revenues $156.9 million), partially offset by an increase in volumes (increased revenues $18.8 million). Wholesale sales reflect the balancing of loads and resources and the sale of resources in excess of load requirements as part of the natural gas procurement process. Additionally, we engage in optimization of under-utilized interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas. Variances between the revenues and costs of the sale of resources in excess of load requirements 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	
	2009	2008	2009	2008
Residential	313,884	311,381	280,667	277,892
Commercial	39,276	39,075	33,214	32,901
Interruptible	—	—	42	40
Industrial	1,394	1,388	258	257
Public street and highway lighting	444	434	—	—
Total retail customers	354,998	352,278	314,181	311,090

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

	2009	2008
Electric resource costs:		
Power purchased	$ 193,683	$ 193,924
Power cost amortizations, net of deferrals	31,102	25,464
Fuel for generation	89,602	134,446
Other fuel costs	31,881	43,103
Other regulatory amortizations, net	19,602	10,490
Other electric resource costs	13,188	17,946
Total electric resource costs	379,058	425,373
Natural gas resource costs:		
Natural gas purchased	389,034	579,248
Natural gas cost amortizations, net of deferrals	20,256	20,372
Other regulatory amortizations, net	11,191	6,996
Total natural gas resource costs	420,481	606,616
Total resource costs	$ 799,539	$ 1,031,989

Power purchased decreased $0.2 million due to a decrease in wholesale prices (decreased costs $35.4 million) offset by an increase in the volume of power purchases (increased costs $35.2 million), primarily due to purchasing power to cover for the outage at Colstrip and an increase in sales volumes related to optimization.

Net amortization of deferred power costs was $31.1 million for 2009 compared to $25.5 million for 2008. During 2009, we recovered (collected as revenue) $31.6 million of previously deferred power costs in Washington and $17.5 million in Idaho. During 2009, we deferred $18.0 million of power costs in Idaho, as power supply costs exceeded the amount included in base retail rates. We did not defer any power costs in Washington during 2009, as power supply costs were within the $4.0 million deadband below the amount included in base retail rates under the ERM.

Fuel for generation decreased $44.8 million due to a decrease in natural gas fuel prices, as well as a decrease in thermal generation (primarily due to the outage at Colstrip).

Other fuel costs decreased $11.2 million. This represents fuel that was purchased for generation, but was later sold when conditions indicated that it was not economical to use the fuel in generation as part of the resource optimization process. The associated revenues are reflected as sales of fuel.

The increase in other regulatory amortizations of $9.1 million primarily relates to the amortization of costs under demand side management programs.

The expense for natural gas purchased decreased $190.2 million due to a decrease in the price of natural gas (decreased costs $214.7 million), partially offset by an increase in the total therms purchased (increased costs $24.5 million). The increase in total therms purchased was due to an increase in wholesale sales with the balancing of loads and resources as part of the natural gas procurement process, partially offset by a decrease in retail sales volumes. We engage in optimization of under-utilized interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas. During 2009, we amortized $20.3 million of deferred natural gas costs compared to $20.4 million for 2008.

2008 COMPARED TO 2007

Net income for the utility was $70.0 million for 2008 compared to $43.8 million for 2007. Utility income from operations was $174.2 million for 2008 compared to $150.1 million for 2007. This increase in income from operations was primarily due to increased gross margin (operating revenues less resource costs). This was partially offset by an increase in other utility 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		Total	
	2008	2007	2008	2007	2008	2007
Operating revenues	$ 838,457	$ 711,130	$ 734,207	$ 577,233	$ 1,572,664	$ 1,288,363
Resource costs	425,373	322,237	606,616	458,761	1,031,989	780,998
Gross margin	$ 413,084	$ 388,893	$ 127,591	$ 118,472	$ 540,675	$ 507,365

Utility operating revenues increased $284.3 million and utility resource costs increased $251.0 million, which resulted in an increase of $33.3 million in gross margin. The gross margin on electric sales increased $24.2 million and the gross margin on natural gas sales increased $9.1 million. The increase in our electric and natural gas gross margin was primarily due to the implementation of general rate increases in Washington effective January 1, 2008 and in Idaho effective October 1, 2008. The increase was also partially due to colder weather in 2008, which increased customer usage, during the heating season and customer growth. The Company absorbed $7.4 million of expense under the ERM in 2008, compared to $8.5 million in 2007.

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	
	2008	2007	2008	2007
Residential	$ 279,641	$ 251,357	3,744	3,670
Commercial	247,714	224,179	3,188	3,132
Industrial	101,785	95,207	2,059	2,084
Public street and highway lighting	5,962	5,517	26	26
Total retail	635,102	576,260	9,017	8,912
Wholesale	141,744	105,729	1,964	1,594
Sales of fuel	44,695	12,910	—	—
Other	16,916	16,231	—	—
Total	$ 838,457	$ 711,130	10,981	10,506

Retail electric revenues increased $58.8 million due to an increase in:

- total MWhs sold (increased revenues $7.3 million) primarily due to customer growth and an increase in use per customer (primarily due to colder weather), and
- revenue per MWh (increased revenues $51.5 million) primarily due to the Washington general rate increase implemented on January 1, 2008 and the Idaho general rate increase implemented on October 1, 2008.

Wholesale electric revenues increased $36.0 million due to an increase in sales prices (increased revenues $9.3 million), and an increase in sales volumes (increased revenues $26.7 million).

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market as sales of fuel. Sales of fuel increased $31.8 million due to increased thermal generation resource optimization activities.

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	
	2008	2007	2008	2007
Residential	$ 276,386	$ 264,546	210,125	195,756
Commercial	152,147	148,416	128,224	121,557
Interruptible	5,428	5,040	5,758	5,003
Industrial	6,731	6,244	6,438	5,830
Total retail	440,692	424,246	350,545	328,146
Wholesale	281,668	142,167	345,916	223,084
Transportation	6,327	6,638	148,723	148,765
Other	5,520	4,182	526	438
Total	$ 734,207	$ 577,233	845,710	700,433

The $16.4 million increase in retail natural gas revenues was due to an increase in volumes (increased revenues $28.1 million), partially offset by lower retail rates (decreased revenues $11.7 million). We sold more retail natural gas in 2008 primarily due to colder weather during the heating season and customer growth. The decrease in retail rates reflects the purchased gas adjustments implemented in the fourth quarter of 2007, partially offset by the Washington general rate increase implemented on January 1, 2008 and Idaho general rate increase implemented on October 1, 2008.

The increase in our wholesale revenues of $139.5 million was due to an increase in prices (increased revenues $39.5 million) and an increase in volumes (increased revenues $100.0 million). Wholesale sales reflect the balancing of loads and resources and the sale of resources in excess of load requirements as part of the natural gas procurement process. Additionally, we engage in optimization of under-utilized interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas. This activity increased significantly in 2008 as compared to 2007. Variances between the revenues and costs of the sale of resources in excess of load requirements 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	
	2008	2007	2008	2007
Residential	311,381	306,737	277,892	273,415
Commercial	39,075	38,488	32,901	32,327
Interruptible	—	—	40	41
Industrial	1,388	1,378	257	261
Public street and highway lighting	434	426	—	—
Total retail customers	352,278	347,029	311,090	306,044

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

	2008	2007
Electric resource costs:		
Power purchased	$ 193,924	$ 158,245
Power cost amortizations, net of deferrals	25,464	3,641
Fuel for generation	134,446	125,043
Other fuel costs	43,103	16,454
Other regulatory amortizations, net	10,490	4,437
Other electric resource costs	17,946	14,417
Total electric resource costs	425,373	322,237
Natural gas resource costs:		
Natural gas purchased	579,248	433,140
Natural gas cost amortizations, net of deferrals	20,372	16,875
Other regulatory amortizations, net	6,996	8,746
Total natural gas resource costs	606,616	458,761
Total resource costs	$ 1,031,989	$ 780,998

Power purchased increased $35.7 million due in part to an increase in wholesale prices (increased costs $23.0 million). The increase was also due to an increase in the volume of power purchases (increased costs $12.7 million) primarily due to an increase in sales volumes (due to colder weather, customer growth and optimization).

Net amortization of deferred power costs was $25.5 million for 2008 compared to $3.6 million for 2007. During 2008, we recovered (collected as revenue) $30.9 million of previously deferred power costs in Washington and $11.7 million in Idaho. During 2008, we deferred $7.0 million of power costs in Washington and $10.0 million of power costs in Idaho, as power supply costs exceeded the amount included in base retail rates.

Fuel for generation increased $9.4 million due to an increase in thermal generation volumes and an increase in fuel prices.

Other fuel costs increased $26.6 million. This represents fuel that was purchased for generation, but was later sold when conditions indicated that it was not economic to use the fuel in generation as part of the resource optimization process. The associated revenues are reflected as sales of fuel. Other fuel costs were less than the revenues we received from selling the natural gas. We account for this difference under the ERM in Washington and the PCA in Idaho. The increase in other fuel costs was primarily due to increased thermal generation resource optimization activities and increased fuel prices.

Other regulatory amortizations increased $6.1 million primarily due to amortization of demand side management program expenses.

The expense for natural gas purchased increased $146.1 million due to an increase in total therms purchased and the price of natural gas. The increase in total therms purchased was due to an increase in wholesale sales as part of the balancing of loads and resources as part of the natural gas procurement process and an increase in retail sales volumes. We engage in optimization of under-utilized interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas. This activity increased significantly in 2008 as compared to 2007. During 2008, we amortized $20.4 million of deferred natural gas costs compared to $16.9 million for 2007.

ADVANTAGE IQ

2009 COMPARED TO 2008

Advantage IQ's net income attributable to Avista Corporation was $5.3 million for 2009 compared to $6.1 million for 2008. Operating revenues increased $18.2 million and operating expenses increased $17.9 million. The increase in operating revenues and expenses was primarily due to the third quarter 2008 acquisition of Cadence Network and the third quarter 2009 acquisition of Ecos, as well as increased revenues from other customer billing services. These increases in operating revenues were partially offset by a decrease in interest revenue on funds held for customers (due to a decrease in interest rates). The increase in operating expenses was also due to the amortization of intangible assets from the acquisitions. As of December 31, 2009, Advantage IQ had 532 customers representing 421,000 billed sites in North America. In 2009, Advantage IQ managed bills totaling $17.4 billion, an increase of $0.7 billion, or 4 percent, as compared to 2008. The acquisition of Cadence Network added $1.7 billion in processed bills for 2009 as compared to 2008.

2008 COMPARED TO 2007

Advantage IQ's net income attributable to Avista Corporation was $6.1 million for 2008 compared to $6.7 million for 2007. Operating revenues increased $11.8 million and operating expenses increased $11.5 million. The increase in operating revenues was primarily due to the expansion of Advantage IQ's customer base and the third quarter acquisition of Cadence Network, partially offset by a decrease in interest revenue on funds held for customers (due to a decrease in interest rates). As of December 31, 2008, Advantage IQ had 537 customers representing 417,000 billed sites in North America, a significant increase from the end of 2007 primarily due to the acquisition of Cadence Network. The increase in operating expenses primarily reflects increased labor and other operational costs necessary to serve an expanding customer base, as well as the third quarter acquisition of Cadence Network (including the amortization of intangible assets). In 2008, Advantage IQ processed bills totaling $16.7 billion, an increase of $4.2 billion, or 34 percent, as compared to 2007. The acquisition of Cadence Network (in July 2008) added $2.1 billion in processed bills for 2008 as compared to 2007.

OTHER BUSINESSES

2009 COMPARED TO 2008

The net loss attributable to Avista Corporation from these operations was $5.0 million for 2009 compared to $2.5 million for 2008. Operating revenues decreased $4.9 million and operating expenses increased $0.8 million. The decrease in operating revenues was primarily due to a reduction in sales at AM&D. The increase in operating expenses reflects the impairment of a commercial building of $3.0 million and increased litigation costs related to the remaining contracts and previous operations of Avista Energy, partially offset by decreased operating costs from AM&D. Losses on long-term venture fund investments were $0.8 million in 2009 compared to $1.4 million in 2008. AM&D had net income of $0.2 million for 2009 compared to $0.5 million for 2008.

2008 COMPARED TO 2007

The net loss attributable to Avista Corporation from these operations was $2.5 million for 2008 compared to $12.0 million for 2007. Operating revenues decreased $37.1 million and operating expenses decreased $59.1 million. Contributing to the net loss attributable to Avista Corporation in 2008 was losses on long-term venture fund investments and litigation costs. The net loss attributable to Avista Corporation for 2007 and the decrease in operating revenues and expenses were primarily due to the sale of Avista Energy in 2007.

ACCOUNTING STANDARDS TO BE ADOPTED IN 2010

We will be adopting the following accounting standards in 2010, which could have an impact on our financial condition, results of operations and cash flows. For information on accounting standards adopted in 2009 and earlier periods, refer to "Note 2 of the Notes to Consolidated Financial Statements."

In June 2009, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 166, "Accounting for Transfers of Financial Assets an amendment of FASB Statement No. 140" (Accounting Standards Codification (ASC) 860). This statement amends certain provisions of SFAS No. 140 (ASC 860) related to accounting for transfers of financial assets and a transferor's continuing involvement in transferred financial assets. We are required to adopt this statement effective January 1, 2010. We are evaluating the impact this statement will have on our financial condition, results of operations and cash flows. In particular, we are evaluating our accounts receivable sales to determine whether or not the transactions meet the criteria of sales of financial assets. If the transactions did not meet the criteria, the transactions would be accounted for as secured borrowings. As of December 31, 2009, we had not sold any accounts receivable under the revolving agreement. We will finalize our evaluation during the first quarter of 2010 to determine the impact of adoption, if any, on our financial condition, results of operations and cash flows.

In June 2009, the FASB issued SFAS No. 167, "Amendments to FASB Interpretation No. 46(R)" (ASC 810). This Statement carries forward the scope of FASB Interpretation No. 46(R) (ASC 810), with the addition of entities previously considered qualifying special-purpose entities, as the concept of these entities was eliminated in SFAS No. 166 (ASC 860). The amendments will significantly affect the overall consolidation analysis of variable interest entities (VIE). The amendments will require us to reconsider previous conclusions relating to the consolidation of VIEs, including whether an entity is a VIE, whether we are the VIE's primary beneficiary, and what type of financial statement disclosures are required. We are required to adopt this statement effective January 1, 2010. We are evaluating the impact this statement will have on our financial condition, results of operations and cash flows. In particular, we are evaluating the potential consolidation of Spokane Energy LLC (see disclosure at "Spokane Energy LLC"). This would add approximately $85 million of assets and liabilities (consisting primarily of a long-term contract receivable and non-recourse debt) to the Consolidated Balance Sheet, with no material effect on our results of operations. In addition, we are evaluating certain long-term power purchase contracts under this guidance. We will finalize our evaluation during the first quarter of 2010 to determine the impact of adoption, if any, on our financial condition, results of operations and cash flows.

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 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 the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (ASC 980) for our regulated utility operations. ASC 980 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 ASC 980 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 11 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 $25.8 million for 2009, $13.9 million for 2008 and $14.3 million for 2007. 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.

In 2009, the Company reviewed the mortality table utilized in the actuarial calculations. The Company determined that the RP-2000 combined healthy mortality tables for males and females should be replaced with the RP-2000 combined healthy mortality tables for males and females projected to 2010 using scale AA. The change resulted in an increase of $6.6 million to the pension benefit obligation as of December 31, 2009.

In 2008, the rates at which participants are assumed to retire by age were analyzed based upon historical trends and future projections. We revised the rates to assume that a greater percentage of participants would retire between the ages of 55 and 65. The assumed rates were revised to range from 5 percent to 40 percent and 100 percent at age 65. The previous rates ranged from 2 percent to 30 percent and 100 percent at age 65. The change resulted in an increase of $11.0 million to the pension benefit obligation as of December 31, 2008. The changes will also increase future years' pension costs.

We have not made any changes to pension plan provisions in 2009, 2008 and 2007 that have had any significant effect on our recorded pension plan amounts. We have revised the key assumption of the discount rate in 2009, 2008 and 2007. Such changes had an effect on our pension costs in 2009, 2008 and 2007 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. We increased the pension plan discount rate from 6.25 percent in 2008 to 6.30 percent in 2009. In 2007 we used the 6.35 percent rate for estimating our benefit obligation.

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. The expected long-term rate of return was 8.5 percent in each of 2009, 2008 and 2007. The actual return on plan assets, net of fees, was a gain of $50.1 million (or 24.4 percent) for 2009, a loss of $63.2 million (or -25.5 percent) for 2008 and a gain of $18.3 million (or 8.1 percent) for 2007. We periodically analyze the estimated long-term rate of return on assets based upon revisions to the investment portfolio.

Effective January 1, 2010, we decreased the expected long-term rate of return on plan assets from 8.5 percent to 7.75 percent. This will increase pension cost in 2010 by approximately $2.0 million. Of our pension costs, approximately 65 percent are expensed and 35 percent are capitalized consistent with labor charges.

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%	$ —*	$ 1,036
Expected long-term return on plan assets	+0.5%	—*	(1,036)
Discount rate	-0.5%	23,677	2,287
Discount rate	+0.5%	(21,353)	(2,081)

** 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, 2009 by $2.1 million and the service and interest cost by $0.2 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, 2009 by $1.9 million and the service and interest cost by $0.2 million.

STOCK-BASED COMPENSATION

We recognize compensation costs relating to share-based payment transactions in our Consolidated Statements of Income based on the fair value of the equity or liability instruments issued. 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 is based on the historical volatility of our 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 is based on the U.S. Treasury yield at the time of grant.

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 for the ultimate outcome of any particular contingency.

LIQUIDITY AND CAPITAL RESOURCES

REVIEW OF CASH FLOW STATEMENT

OVERALL — During 2009, positive cash flows from operating activities of $258.8 million and proceeds from the issuance of long-term debt of $249.4 million were used to fund the majority of our cash requirements. These cash requirements included utility capital expenditures of $205.4 million, a net decrease (net repayment) in short-term borrowings of $159.5 million, redemption of long-term debt to affiliated trusts of $61.9 million and dividends of $44.4 million.

OPERATING ACTIVITIES — Net cash provided by operating activities was $258.8 million for 2009 compared to $115.4 million for 2008. Net cash provided by working capital components was $31.0 million for 2009, compared to cash used of $113.8 million for 2008. The net cash provided during 2009 primarily reflects an increase in cash flows from:

- accounts receivable (representing a decrease in the receivables outstanding largely due to a decrease in wholesale prices, partially offset by a $17.0 million decrease in the amount of receivables that were sold),
- other current liabilities, and
- materials and supplies, fuel stock and natural gas stored (primarily reflecting a change in the price of natural gas stored).

This cash provided was partially offset by negative cash flows from accounts payable (primarily related to a decrease in the accounts payable for natural gas purchases due to a decrease in prices).

The net cash used during 2008 primarily reflects a decrease in cash flows from:

- accounts receivable (representing an increase in the receivables outstanding and a $68.0 million decrease in the amount of receivables that were sold),
- deposits from counterparties (representing the return to counterparties of cash posted as collateral at Avista Utilities), and
- materials and supplies, fuel stock and natural gas stored (primarily representing an increase in natural gas that was stored).

This cash used in 2008 was partially offset by positive cash flows from accounts payable (representing an increase in accounts payable).

Significant non-cash items included $51.4 million of power and natural gas cost amortizations, net of deferrals, for 2009, an increase from $45.8 million for 2008. We also had deferred income tax expense of $13.9 million for 2009 compared to $44.2 million for 2008. Contributions to our defined benefit pension plan were $48.0 million for 2009 compared to $28.0 million for 2008. Income tax payments were $22.7 million in 2009, an increase compared to $10.0 million for 2008. Cash paid for interest decreased to $58.8 million for 2009, compared to $76.6 million in 2008.

INVESTING ACTIVITIES — Net cash used in investing activities was $215.6 million for 2009, an increase compared to $185.3 million for 2008. Utility property capital expenditures decreased for 2009 as compared to 2008, and funds held from customers at Advantage IQ decreased by $8.5 million.

FINANCING ACTIVITIES — Net cash used in financing activities was $30.5 million for 2009 compared to net cash provided of $82.4 million for 2008. In September 2009, we issued $250.0 million (net proceeds of $249.4 million) of long-term debt. In conjunction with the issuance of long-term debt, we cash settled interest rate swap agreements and received a total of $10.8 million. In April 2009, we redeemed $61.9 million of long-term debt to affiliated trusts. In December 2009, we purchased $17.0 million of our Pollution Control Bonds, which we are holding as bondholder. During 2009, our short-term borrowings decreased $159.5 million due to a net decrease of $163.0 million in the amount of debt outstanding under our $320.0 million committed line of credit, partially offset by a $3.5 million net increase in the amount borrowed under Advantage IQ's credit agreement. Cash dividends paid increased to $44.4 million (or 81 cents per share) for 2009 from $37.1 million (or 69 cents per share) for 2008. Additionally, customer funds obligations at Advantage IQ decreased by $8.5 million.

During 2008, our short-term borrowings increased $252.2 million, which reflected a net increase in the amount of debt outstanding under our $320.0 million committed line of credit. Net proceeds from long-term debt issuances were $296.2 million in 2008 and common stock issuances were $28.6 million for 2008 (primarily $16.6 million from the issuance of 750,000 shares of common stock under a sales agency agreement). Debt maturities were $403.9 million and cash paid to settle interest rate swaps was $16.4 million in 2008. Additionally, customer funds obligations at Advantage IQ decreased by $30.8 million.

OVERALL LIQUIDITY

Our consolidated operating cash flows are primarily derived from the operations of Avista Utilities. The primary source of operating cash flows for our utility operations is revenues from sales of electricity and natural gas. Significant uses of cash flows from our utility operations include the purchase of electricity 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 optimize capital expenditures, particularly for our regulated utility operations. In addition to operating expenses, we have continuing commitments for capital expenditures for construction, improvement and maintenance of utility facilities.

Over time, our operating cash flows usually do not fully support the amount required for utility capital expenditures. As such, from time to time, we need to access capital markets in order to fund these needs as well as fund maturing debt. See further discussion at "Capital Resources."

We periodically file for rate adjustments for recovery of operating costs and capital investments to provide the opportunity to align our earned returns with those allowed by regulators. Effective January 1, 2009, the WUTC authorized an increase in our rates in Washington designed to increase annual electric revenues by $32.5 million and annual natural gas revenues by $4.8 million. Effective August 1, 2009, the IPUC authorized an increase in our electric rates in Idaho designed to increase annual electric revenues by $12.5 million. Offsetting the electric revenue increase was an overall decrease in the current PCA surcharge, which is designed to decrease annual electric revenues by

$9.3 million. Effective August 1, 2009, the IPUC authorized an increase in our natural gas rates in Idaho designed to increase annual revenues by $1.9 million. Offsetting the natural gas rate increase was an overall PGA decrease resulting in a $2.0 million decrease in annual revenues. Effective January 1, 2010, the WUTC authorized an increase in our rates in Washington designed to increase annual electric revenues by $12.1 million and annual natural gas revenues by $0.6 million. In addition, PGA decreases were implemented in all of our jurisdictions and a general rate increase was implemented in Oregon effective November 1, 2009. 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 costs to exceed the levels currently recovered from our customers include, but are not limited to, higher prices in wholesale markets when we buy energy or an increased need to purchase power in the wholesale markets. Factors beyond our control that could result in an increased need to purchase power in the wholesale markets include, but are not limited to:

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

We monitor the potential liquidity impacts of increasing energy commodity prices and other increased operating costs for our utility operations. We believe that we have adequate liquidity to meet the increased cash needs of higher energy commodity prices and other increased operating costs through our:

- $320.0 million committed line of credit (which expires in April 2011),
- $75.0 million committed line of credit (which expires in April 2011), and
- $85.0 million revolving accounts receivable sales facility (which expires in March 2010).

As of December 31, 2009, we had a combined $364.6 million of available liquidity under the three facilities described above.

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

CREDIT AND NONPERFORMANCE RISK

Our contracts for the purchase and sale of energy commodities 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 our credit ratings or adverse changes in market prices. 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, 2009, that we would potentially be required to post additional collateral up to $39 million. The additional collateral amount is higher than the amount disclosed in Note 7 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 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, 2009, we did not have any interest rate swap agreements outstanding.

Our utility held cash deposits from other parties in the amount of $3.2 million as of December 31, 2009 and $0.2 million as of December 31, 2008. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of collateral.

In December 2009, the U.S. House of Representatives passed the Wall Street Reform and Consumer Protection Act of 2009 (the House Bill) which would establish regulatory jurisdiction by the Commodity Futures Trading Commission (CFTC) for certain swaps (which includes a variety of derivative instruments) and the users of such swaps. Under the House Bill, "major swap participants" would be required to register with the CFTC and, among other things, maintain minimum capital and margin requirements. "Major swap participants" would include entities with large swap positions, excluding swaps held primarily for hedging commercial risk. Since we use derivative instruments primarily for hedging commercial risks, it is unlikely that we would be subject to the proposed CFTC regulation.

The House Bill would also require a broad category of swaps to be cleared and traded on registered exchanges or special derivatives exchanges. Such clearing requirements could impose a significant change from our current practices of bilateral transactions and negotiated credit terms. Clearing requirements could involve greater liquidity as collateral. However, there would be an exemption, available on an individual basis, for an end user that is not a major swap participant, and we believe we would qualify for such an exemption. Although the House Bill may not have a material direct adverse effect on us, concern remains that our counterparties who are not exempt would pass along increased costs and margin requirements through higher prices and reductions in unsecured credit limits. In addition, there can be no assurance that any final legislation affecting derivatives, if enacted, would retain the exemptions contained in the House Bill.

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, 2009 and 2008 (dollars in thousands):

	December 31, 2009		December 31, 2008	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 35,189	1.5%	$ 17,207	0.8%
Short-term borrowings (1)	92,700	4.1	252,200	11.5
Long-term debt to affiliated trusts (2)	51,547	2.3	113,403	5.2
Long-term debt (1)	1,036,149	45.7	809,258	37.0
Total debt	1,215,585	53.6	1,192,068	54.5
Total Avista Corporation stockholders' equity	1,051,287	46.4	996,883	45.5
Total	$ 2,266,872	100.0%	$ 2,188,951	100.0%

(1) *In September 2009, we issued $250.0 million of 5.125 percent First Mortgage Bonds due in 2022. The net proceeds from the issuance of $249.4 million (net of discounts and before Avista Corp.'s expenses) were used to retire variable rate short-term borrowings outstanding under our $320.0 million committed line of credit, and for general corporate purposes.*

(2) *On April 1, 2009, we redeemed the total amount outstanding ($61.9 million) of our 6.5 percent Junior Subordinated Debt Securities held by AVA Capital Trust III (Long-term Debt to Affiliated Trusts). Concurrently, AVA Capital Trust III redeemed all of the Preferred Trust Securities issued to third parties ($60.0 million) and all of the Common Trust Securities issued to us ($1.9 million). The net redemption of $60.0 million was funded by borrowings under our $320.0 million committed line of credit agreement.*

We need to finance capital expenditures and obtain additional working capital 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, working capital, purchased power and natural gas costs, dividends and other requirements. Our stockholders' equity increased $54.4 million during 2009 primarily due to net income, partially offset by dividends.

We generally fund capital expenditures with a combination of internally generated cash and external financing. The level of cash generated internally and the amount that is available for capital expenditures fluctuates depending on a variety of factors. Cash provided by our utility operating activities is expected to be the primary source of funds for operating needs, dividends and capital expenditures for 2010. Borrowings under our $320.0 million committed line of credit, $75.0 million committed line of credit and sales of accounts receivable under our $85.0 million revolving facility will supplement these funds to the extent necessary.

We have $35.0 million of scheduled long-term debt maturities in 2010. In December 2009, we purchased $17.0 million of our Pollution Control Bonds. We are planning, subject to market conditions, to refund these bonds in 2010 along with $66.7 million of our Pollution Control Bonds we purchased in December 2008.

We are planning to issue up to $45 million of common stock in 2010 in order to maintain our capital structure at an appropriate level for our business.

We have a committed line of credit in the total amount of $320.0 million with an expiration date of April 2011. Under the credit agreement, we can borrow or request the issuance of letters of credit in any combination up to $320.0 million. As of December 31, 2009, we had $87.0 million in borrowings outstanding under this committed line of credit, a decrease from $250.0 million in borrowings outstanding as of December 31, 2008. As of December 31, 2009, there were $28.4 million in letters of credit outstanding, an increase from $24.3 million as of December 31, 2008. The committed line of credit is secured by $320.0 million of non-transferable First Mortgage Bonds issued to the agent bank. Such First Mortgage Bonds would only become due and payable in the event, and then only to the extent, that we default on obligations under the committed line of credit.

Additionally, in November 2009, we entered into a new committed line of credit in the total amount of $75.0 million with an expiration date of April 2011. The new committed line of credit replaced a $200.0 million committed line of credit that expired in November 2009. We reduced the facility based on our forecasted liquidity needs. As of December 31, 2009, we did not have any borrowings outstanding under this committed line of credit. The committed line of credit is secured by $75.0 million of non-transferable First Mortgage Bonds issued to the agent bank. Such First Mortgage Bonds would only become due and payable in the event, and then only to the extent, that we default on obligations under the committed line of credit.

Our committed line of credit agreements contain customary covenants and default provisions, including a covenant requiring the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Utilities for the preceding twelve-month period at the end of any fiscal quarter to be greater than 1.6 to 1. As of December 31, 2009, we were in compliance with this covenant with a ratio of 4.23 to 1. The committed line of credit agreements also have a covenant which does not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 70 percent at any time. As of December 31, 2009, we were in compliance with this covenant with a ratio of 53.6 percent.

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. We do not guarantee the indebtedness of any of our subsidiaries. As of December 31, 2009, Avista Corp. and our subsidiaries were in compliance with all of the covenants of our financing agreements.

We are restricted under our Restated Articles of Incorporation as to the additional preferred stock we can issue. As of December 31, 2009, we could issue $611.0 million of additional preferred stock at an assumed dividend rate of 9.5 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:

- 70 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;

provided, however, that 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, 2009, our property additions and retired bonds would have entitled us to issue $668.5 million in aggregate principal amount of additional First Mortgage Bonds. However, using an interest rate of 8 percent on additional First Mortgage Bonds, and based on net earnings for the 12 months ended December 31, 2009, the net earnings test would limit the principal amount of additional bonds we could issue to $607.5 million. We believe that we have adequate capacity to issue First Mortgage Bonds to meet our financing needs over the next several years.

In December 2009, we entered into an amended and restated sales agency agreement with a sales agent to issue up to 1.25 million shares of our common stock from time to time. We originally entered into a sales agency agreement to issue up to 2 million shares of our common stock in December 2006. In 2008, we issued 750,000 shares of our common stock under this sales agency agreement. We did not issue any common stock under this agreement in 2009.

AVISTA UTILITIES CAPITAL EXPENDITURES

Capital expenditures for our utility were $630.4 million for the years 2007 through 2009. We expect utility capital expenditures to be over $210 million for each of 2010, 2011 and 2012. In addition to ongoing needs for our distribution system, significant projects include upgrades to generating facilities. These estimates of capital expenditures are subject to continuing review and adjustment and do not include costs for projects associated with stimulus funding (see discussion below). Actual capital expenditures may vary from our estimates due to factors such as changes in business conditions, construction schedules and environmental requirements.

We are committed to investment in generation, transmission and distribution systems with a focus on increasing capacity and maintaining or improving reliability. We continue to upgrade hydroelectric plants to maintain reliable operations and improve output.

The American Recovery and Reinvestment Act (the ARRA) of 2009 includes almost $80 billion of stimulus funding in areas that have some relation to electric and natural gas utilities, such as Avista Corp. We applied to the Smart Grid Investment Grant program under the ARRA, proposing a 50 percent cost share for the deployment of smart grid enabling technologies in the Spokane area. The total project costs are estimated to be $42 million, which will be spent over a three-year period. In October 2009, we were one of 100 utilities selected to negotiate a grant under this stimulus program. The grant will be for $20 million and our contribution will be $22 million. We are working with the Department of Energy to finalize the grant in early 2010.

In August 2009, we applied with Battelle Northwest to participate in a Smart Grid Demonstration Project in Pullman, Washington under the ARRA. In November 2009, this project was selected by the Department of Energy for a grant, which it will negotiate with us and the other partners to reach a funding agreement. The Smart Grid Demonstration Project will partner with other regional utilities and proposes a 50 percent cost share for a group of projects. Our portion of the regional demonstration project is estimated to cost $16 million. The Smart Grid Demonstration Project will spend the funds over the course of five years.

We are subject to Washington state renewable energy portfolio standards and must obtain a portion of our electricity from qualifying renewable resources or through purchase of renewable energy credits. Our 2009 Integrated Resource Plan (IRP) identified that additional qualifying renewable energy is needed by 2016 and that new capacity and energy resources are needed by 2018. Based on resource acquisition goals identified in the 2009 IRP, we evaluated proposals from suppliers to provide us with up to 35 average megawatts (which equates to approximately 105 MW of wind power) of long-term qualified renewable energy by the end of 2012.

In 2008, we completed the acquisition of the development rights for a wind generation site. We considered developing this site and/or acquiring additional renewable resources a few years early by taking advantage of certain federal and state tax incentives. However, after detailed analysis, we decided to postpone renewable resource acquisitions, including the potential construction of a wind generation project until the 2014-2015 timeframe.

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

We are participating in planning activities for the development of a proposed 3,000 MW transmission project that would extend from British Columbia, Canada to Northern California. Other participants include Pacific Gas and Electric Company and British Columbia Transmission Corporation. We have executed an agreement (stage one agreement) with the other participants in order to perform preliminary studies and assessments for the project, including electrical system studies and resource mapping of possible transmission line corridors. Under the stage one agreement, we have committed to contribute $0.6 million. The participants are working on a stage two agreement for the project that is expected to be completed in the second quarter of 2010, which, among other things, will determine our financial obligation and participation in the project. The stakeholders continue to have discussions to explore whether, in light of changing circumstances for other project participants, this project, a different version of this project or another transmission project in the region should be pursued.

ADVANTAGE IQ CREDIT AGREEMENT

Advantage IQ has a committed credit agreement with an expiration date of February 2011. In July 2009, the committed amount was increased from $12.5 million to $15.0 million under the terms of the credit agreement. Advantage IQ may elect to increase the credit facility to $25.0 million under the same agreement. The credit agreement is secured by substantially all of Advantage IQ's assets. Advantage IQ had $5.7 million of borrowings outstanding under the credit agreement as of December 31, 2009, compared to $2.2 million as of December 31, 2008. The increase in the amount borrowed primarily reflects the funding of the Ecos acquisition, partially offset by repayments.

ADVANTAGE IQ OPERATIONS

We do not expect capital expenditures for the years 2010 through 2012 for Advantage IQ to be significant to our consolidated cash flows and financial condition. These capital expenditures are expected to be funded by Advantage IQ's cash flows from operations.

In 2007, Advantage IQ amended its employee stock incentive plan to provide an annual window at which time holders of common stock can put their shares back to Advantage IQ providing the shares are held for a minimum of six months. Stock is reacquired at fair market value at the date of reacquisition. This plan was amended to provide liquidity to participants of Advantage IQ's stock option plan. As the repurchase feature is at the discretion of the minority shareholders and option holders, there was redeemable noncontrolling interests of $6.9 million as of December 31, 2009 for the intrinsic value of stock options outstanding, as well as outstanding redeemable stock. Additionally, there was redeemable noncontrolling interests of $27.9 million related to the Cadence Network acquisition, as the previous owners can exercise a right to put their stock back to Advantage IQ (refer to Note 5 of the Notes to Consolidated Financial Statements for further information). During 2009, $4.7 million of common stock was repurchased from Advantage IQ employees. In 2009, the Advantage IQ employee stock incentive plan was amended such that, on a prospective basis, not all options granted under the plan will have the annual put window.

OFF-BALANCE SHEET ARRANGEMENTS

Avista Receivables Corporation (ARC) is our wholly owned, bankruptcy-remote subsidiary formed for the purpose of acquiring or purchasing interests in certain of our accounts receivable, both billed and unbilled. On March 13, 2009, Avista Corp., ARC and Bank of America, N.A. amended a Receivables Purchase Agreement. The most significant amendment was to extend the termination date from March 13, 2009 to March 12, 2010. The Receivables Purchase Agreement was originally entered into on May 29, 2002 and provides us with cost-effective funds for:

- working capital requirements,
- capital expenditures, and
- other general corporate needs.

Under the Receivables Purchase Agreement, ARC can sell without recourse, on a revolving basis, up to $85.0 million of our receivables. ARC is obligated to pay fees that approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of our committed line of credit agreements. As of December 31, 2009, we had the ability to sell up to $85.0 million of receivables (based on calculations of our eligible accounts receivable) and there were not any accounts receivable sold under this revolving agreement. We expect to renew this facility before the March 12, 2010 expiration.

We are evaluating accounts receivable sales under SFAS No. 166, which amends ASC 860, to determine whether or not the transactions meet the criteria of sales of financial assets. If the transactions did not meet the criteria, the transactions would be accounted for as secured borrowings.

As of December 31, 2009, we had $28.4 million in letters of credit outstanding under our $320.0 million committed line of credit, an increase from $24.3 million as of December 31, 2008.

SPOKANE ENERGY, LLC

In December 1998, we received cash proceeds of $143.4 million from a transaction in which we assigned and transferred certain rights under a long-term power sales contract with Portland General Electric Company (PGE) to a funding trust. Pursuant to orders from the WUTC and the IPUC, we fully amortized this amount by the end of 2002.

Under this power exchange arrangement, Peaker, LLC (Peaker) purchases capacity from our utility and sells capacity to Spokane Energy LLC (Spokane Energy), our unconsolidated subsidiary formed in 1998 solely for the purpose of facilitating a long-term capacity contract between PGE and Avista Corp. Spokane Energy sells the related capacity to PGE. Peaker acts as an intermediary to fulfill certain regulatory requirements between Spokane Energy and Avista Corp. The transaction is structured such that Spokane Energy bears full recourse risk for a loan (balance of $70.3 million as of December 31, 2009) that matures in January 2015. Avista Corp. has no recourse related to this loan. Peaker makes monthly payments (which are not material to our financial statements) to Avista Corp. for its capacity purchase.

We are currently evaluating Spokane Energy under the provision of SFAS No. 167, which amends ASC 810. This could result in the consolidation of Spokane Energy beginning in 2010. The consolidation of Spokane Energy would add approximately $85 million of assets and liabilities (consisting primarily of a long-term contract receivable and non-recourse debt) to the Consolidated Balance Sheet, with no material effect on our results of operations.

CREDIT RATINGS

The following table summarizes our credit ratings as of February 26, 2010:

	Standard & Poor's (1)	Moody's (2)	Fitch, Inc. (3)
Avista Corporation			
Corporate/Issuer rating	BBB-	Baa3	BBB-
Senior secured debt (4)	BBB+	Baa1	BBB+
Senior unsecured debt	N/A (7)	Baa3	BBB
Avista Capital II (5)			
Preferred Trust Securities	BB	Ba1	BB+ (8)
Rating outlook (6)	Positive	Positive	Stable

(1) Ratings were upgraded in February 2008.

(2) Ratings were upgraded in December 2007, and the senior secured debt rating was further upgraded to Baa1 from Baa2 in August 2009.

(3) Ratings were upgraded in May 2009.

(4) Based on our understanding of the methodology currently used by Standard & Poor's, the rating on senior secured debt may depend on, among other things, the amount of our utility property (net of depreciation) relative to the amount of such debt outstanding and the amount currently issuable. Thus, the rating on senior secured debt as of any particular time may depend on factors affecting our utility property accounts, as well as factors affecting the principal amount of such debt issued and issuable, including factors affecting our net income.

(5) Only assets are subordinated debentures of Avista Corporation.

(6) Rating outlook for Standard & Poor's and Moody's was changed to "Positive" from "Stable" in August 2009.

(7) Standard & Poor's has not assigned a rating to our senior unsecured debt. We do not have any senior unsecured debt outstanding.

(8) Rating outlook on these securities was changed to BB+ from BBB- in January 2010. Downgrade was a result of a corporate-wide change in methodology for Fitch, Inc. related to the rating of preferred trust securities.

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 independently of all other ratings.

PENSION PLAN

As of December 31, 2009, our pension plan had assets with a fair value that was less than the benefit obligation under the plan. Due to market conditions and the decline in the fair value of pension plan assets in 2008, we contributed $48 million to the pension plan in 2009. We contributed $28 million to the pension plan in 2008 and $15 million in both 2006 and 2007. In 2009, the fair value of pension plan assets increased. We expect that our contribution for 2010 will be $21 million. 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 projected benefit obligation).

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 contained in our Restated Articles of Incorporation, as amended.

In February 2010, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.25 per share on the Company's common stock.

CONTRACTUAL OBLIGATIONS

The following table provides a summary of our future contractual obligations as of December 31, 2009 (dollars in millions):

	2010	2011	2012	2013	2014	Thereafter
Avista Utilities:						
Long-term debt maturities	$ 35	$ —	$ 7	$ 75	$ —	$ 955
Long-term debt to affiliated trusts	—	—	—	—	—	52
Interest payments on long-term debt (1)	63	61	61	60	56	615
Short-term borrowings	87	—	—	—	—	—
Energy purchase contracts (2)	367	227	167	124	115	918
Public Utility District contracts (2)	3	3	3	2	2	31
Operating lease obligations (3)	1	1	1	1	1	3
Other obligations (4)	51	55	48	52	53	574
Information services contracts	13	13	12	—	—	—
Pension plan funding (5)	21	21	21	21	21	—
Avista Capital (consolidated):						
Long-term debt	—	—	—	—	—	2
Short-term debt	6	—	—	—	—	—
Redeemable noncontrolling interests (6)	7	28	—	—	—	—
Venture funds investments (7)	2	2	1	—	—	—
Operating lease obligations (3)	3	3	3	2	2	4
Total contractual obligations	$ 659	$ 414	$ 324	$ 337	$ 250	$ 3,154

(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, 2009.*

(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 2014. We cannot reasonably estimate pension plan contributions beyond 2014 at this time.*

(6) *Under the transaction agreement, the previous owners of Cadence Network can exercise a right to have their shares of Advantage IQ common stock redeemed during July 2011 or July 2012 if Advantage IQ is not liquidated through either an initial public offering or sale of the business to a third party. Their redemption rights expire July 31, 2012. The redemption price would be determined based on the fair market value of Advantage IQ at the time of the redemption election as determined by certain independent parties. In addition, certain shares acquired under Advantage IQ's employee stock incentive plan are redeemable at the option of the shareholder.*

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

These contractual obligations do not include income tax payments.

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 set 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.

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.

We actively monitor and participate, as appropriate in energy industry developments, to maintain and enhance the ability to effectively participate in wholesale energy markets consistent with our business goals.

Advantage IQ 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 Advantage IQ to be the first to market a new product or service to gain the advantage in market share. Other challenges for Advantage IQ include the availability of funding and resources to meet capital needs, and rapidly advancing technologies which requires continual product enhancement to avoid obsolescence.

LONG-TERM ECONOMIC AND UTILITY LOAD GROWTH

Based on our forecast for electric customer growth to average 1.1 to 1.6 percent and natural gas customer growth to average 1.3 to 2.3 percent within our service area, we anticipate retail electric and natural gas load growth will average between 1.3 and 1.8 percent annually for the four-year period 2010-2013. While the number of electric customers is growing, the average annual usage by each residential electric customer has stabilized. Natural gas sales growth has 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 projections 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 forward-looking 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.

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

Environmental laws and regulations may:

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

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.

Rising concerns about long-term global climate changes could have a significant effect on our business. Our operations could also be affected by changes in laws and regulations intended to mitigate the risk of global climate changes, including restrictions on the operation of our power generation resources. Changing temperatures and precipitation, including snowpack conditions, affect the availability and timing of the streamflows, which impacts hydroelectric generation. Changing temperatures could also increase or decrease customer demand.

Greenhouse gas requirements could result in significant costs for us to comply with restrictions on carbon dioxide or other greenhouse gas emissions. Such requirements 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 national, regional, or state greenhouse gas requirements. In particular, a greenhouse gas bill was passed by the legislature in the state of Washington and a bill was approved by the U.S. House of Representatives. There will most likely be continuing activity in the near future.

Although we are actively monitoring developments for climate change and restrictions on greenhouse gas emissions, it is important to note that we have relatively low emissions as compared to other investor-owned utilities in the U.S. With 56 percent of our net generation capability from hydroelectric 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.

We have a Climate Change Committee (CCC) (an interdisciplinary team of management and other employees) which is designed to:

- anticipate and evaluate strategic needs and opportunities relating to climate change;
- analyze the company-wide implications of various trends and proposals;
- develop recommendations on positions and action plans; and
- facilitate internal and external communications regarding climate change issues.

Longer term issues involve emissions tracking and certification, providing recommendations for greenhouse gas reduction goals and activities, evaluating the merits of different reduction programs, actively participating in the development of legislation, and benchmarking climate change policies and activities against other organizations.

NATIONAL LEGISLATION

In June 2009, the U.S. House of Representatives approved the American Clean Energy and Security Act of 2009 (H.R. 2454), which includes a mandatory cap-and-trade program for reducing greenhouse gas emissions, a national renewable electricity standard and a number of other energy-related provisions. The cap-and-trade program would begin for electric generators in 2012 and for natural gas local distribution companies in 2016. H.R. 2454 requires that greenhouse gas emissions be reduced by 3 percent below 2005 levels by 2012, 17 percent by 2020, 42 percent by 2030 and 83 percent by 2050. Starting in 2012, covered entities such as fossil-fired power plants must submit to the EPA allowances to emit equal to their greenhouse gas emissions. A different bill (with similar greenhouse gas emissions reduction requirements) S. 1733 is now under consideration in the U.S. Senate.

STATE ACTIVITIES

The states of Washington and Oregon have statutory targets to reduce greenhouse gas emissions. Washington requires reductions to 1990 levels by 2020; to 25 percent below 1990 levels by 2035; and to 50 percent below 1990 levels by 2050. Oregon's goals would reduce greenhouse gas emissions to 10 percent below 1990 levels by 2020 and 75 percent below 1990 levels by 2050. Both states enacted their goals expecting that they would be met through a combination of renewable energy standards, cap-and-trade regulation, and "complementary policies," such as energy efficiency codes for buildings and vehicle emission standards. Washington and Oregon continue to participate in the Western Climate Initiative (WCI), along with the states of Arizona, California, New Mexico, Utah and Montana, and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. The WCI has developed a regional cap-and-trade program with an overall regional goal for reducing greenhouse gas emissions to 15 percent below 2005 levels by 2020. In September 2008, the WCI members released recommendations for the design of such a program, which would apply cap-and-trade regulation to the electricity sector in 2012 and to emissions associated with the distribution of natural gas by 2015. A central element of the WCI's recommendations is a requirement that its members regulate greenhouse gas emissions from sources of electricity that serve loads within their respective jurisdictions, even though those sources may be located beyond their boundaries. This measure is intended to minimize emissions "leakage" and is a principal feature of California Assembly Bill 32 (AB 32). AB 32 was enacted in California in 2006 and obligates the state to implement greenhouse gas emission regulations. The California Air Resources Board, which has been charged to implement and enforce greenhouse gas emission regulations under AB 32, is on schedule to adopt cap-and-trade regulations by January 1, 2012.

In 2009, the Governor of Washington issued an Executive Order (09-05) directing the Washington Department of Ecology to estimate greenhouse gas emissions by sector and source and to identify potential reduction requirements for them in preparation for the eventual imposition of state and/or federal greenhouse gas regulations. The Department of Ecology has identified "facilities" that emit more than 25,000 metric tons of greenhouse gases annually and has forecasted that those facilities will need to reduce their emissions by 9 percent in order for the state to achieve its greenhouse gas emissions reduction target for 2020. Our natural gas distribution system has been specifically identified as a "facility" and our thermal plants and contracts with thermal plants, including fossil-fueled generation outside of the state have been generically deemed a "facility" for the purposes of potentially regulating emissions associated with the importation of power to serve our Washington loads. The state of Washington has yet to disclose how it might intend to impose and enforce emission reductions.

Washington and Oregon apply a greenhouse gas emissions performance standard to electric generation facilities used to serve loads in their jurisdiction. The emissions performance standard prevents utilities from entering into long-term contracts (five years or more) to purchase energy produced by plants that have emission levels higher than the latest commercially available natural gas-fired combined-cycle combustion turbine technology. Washington's emission performance standard has been set by statute at 1,100 pounds of greenhouse gases 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 established in 2010. Failure to comply with renewable energy and energy efficiency standards will result in penalties of at least $50 per MWh being assessed against a utility for each MWh it is deficient in meeting a standard. A utility would be deemed to comply with the renewable energy standard if it invests at least 4 percent of its total annual retail revenue requirement on the incremental costs of renewable energy resources and/or renewable energy credits.

ELECTRIC INTEGRATED RESOURCE PLAN

Our most recent Electric Integrated Resource Plan (IRP), which we filed with the WUTC and the IPUC in the third quarter 2009, includes the acquisition of additional renewable resources such that, if the IRP is implemented, we would be compliant with the requirements of I-937 by the various milestone dates. Highlights of the IRP include:

- Up to 150 MW of wind power by 2012 (which equates to approximately 50 average megawatts),
- An additional 200 MW of wind power by 2022,
- 750 MW of clean-burning natural gas-fired generation facilities,

- Aggressive energy efficiency measures to reduce generation requirements by 26 percent or 339 MW,
- Transmission upgrades are needed to integrate new generation resources into our system, and
- Hydroelectric upgrades at existing facilities will generate additional renewable energy.

After a detailed analysis, we decided to postpone renewable resource acquisitions, including the potential construction of a wind generation project until the 2014-2015 timeframe. We plan to meet the state of Washington's renewable energy standards until 2016 with a combination of qualified hydroelectric upgrades and the purchase of a small amount renewable energy credits from 2012 through 2015. The amount of renewable resources in our future IRPs could change if the cost effectiveness of those resources changes.

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 a one degree warming every 25 years. Incorporating the warming trend finds that in 20 years summer load would be approximately 26 aMW higher than the 30-year average. In the winter, loads would be approximately 40 aMW lower in 2029, for a net impact of a 14 aMW load decrease. Our projected system load for 2010 is 1,101 aMW. We do not expect this trend to have a material impact on our results of operations. Estimated costs of greenhouse gas emissions credits were also included in the development of the IRP market prices.

CHICAGO CLIMATE EXCHANGE

In October 2007, we became a member of the Chicago Climate Exchange (CCX), North America's only voluntary, verifiable and legally binding emissions reduction and trading marketplace for all six greenhouse gases. Members agree to reduce their greenhouse gas emissions by 6 percent from an established baseline by 2010. The CCX allows participants who exceed their reduction targets to bank or sell the excess CCX Carbon Financial Instruments. We liquidated our 2007 surplus credits in June and July 2009. The audit establishing our 2008 baseline emissions was completed and we received 1,519 of 2008 vintage CCX Carbon Financial Instruments in September 2009. The 2009 emissions audit data will be submitted in the second quarter of 2010. We anticipate having surplus credits for the 2009 compliance year, and expect to receive them in the fourth quarter of 2010.

NATIONAL AMBIENT AIR QUALITY STANDARDS

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

RECENT EPA INITIATIVES RELATED TO CLIMATE CHANGE

After a public comment and review period, in December 2009, the EPA Administrator signed two findings regarding greenhouse gases under section 202(a) of the Clean Air Act. The first finding is that the current and projected concentrations of the six key well-mixed greenhouse gases — carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride — in the atmosphere threaten the public health and welfare of current and future generations. The second finding is that the combined emissions of these well-mixed greenhouse gases from new motor vehicles and new motor vehicle engines contribute to the greenhouse gas pollution which threatens public health and welfare.

In September 2009, the EPA published a final rule to regulate facilities emitting over 25,000 metric tons of greenhouse gases (GHG) a year under existing Clean Air Act authority. The rule became effective on December 29, 2009. Data collection commenced January 1, 2010 and covered facilities will be required to submit their first GHG emissions report to the EPA by March 31, 2011. Based on rule applicability criteria, Colstrip, Coyote Springs 2, and the Rathdrum CT will be required to report GHGs. These facilities currently report carbon dioxide to the EPA under the Acid Rain Program and it is expected that the operators of Colstrip and Coyote Springs 2 will be responsible for any additional GHG reporting. Based on our evaluation of historical emissions from 2004-2008, none of our other electrical generation facilities meet the threshold requirements. The proposed rule also requires natural gas distribution system throughput be reported. Monitoring methods per the rule are currently in place and development of a GHG Monitoring Plan for covered facilities is currently underway and will be in place prior to the April 1, 2010 deadline for required monitoring method implementation. The purpose of the plan is to document the process and procedures for collecting and reviewing the data needed to estimate annual GHG emissions.

COAL ASH MANAGEMENT/DISPOSAL

Currently, coal combustion byproducts (CCBs) are not regulated by the EPA as a hazardous waste. The EPA is currently reconsidering the classification of CCBs under the Resource Conservation and Recovery Act (RCRA). A draft proposal is under review at the Office of Budget and Management, but no proposal regarding such regulation has been issued for public review or comment. 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. However, given that no rulemaking proposal has been issued, it is impossible to evaluate the impact of a future regulatory action. We are tracking these developments as information becomes available.

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, 2009, 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 24 of the Notes to Consolidated Financial Statements" for further information on the refund proceedings.

For other environmental issues and other contingencies see "Note 24 of the Notes to Consolidated Financial Statements."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

GENERAL

Our power supply cost varies because of several factors. We optimize the mix of power resources to meet our retail customer requirements and other obligations. We also use our resources and obtain resources from others in the wholesale power market (including natural gas fuel markets). Hydroelectric generation is typically the least cost source of supply, but the amount of hydroelectric generation depends on streamflow conditions (affected by both the volume and timing of precipitation, including snow melt patterns) and other factors in the watersheds for our hydroelectric facilities. Thermal generation resource costs vary with fuel costs and other factors. 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). Generating resource availability and regional demand tend to impact energy prices, which affect our net power supply costs.

Even with regulatory cost recovery mechanisms that address these power supply cost variations, a portion of the cost variation is not passed on to customers. In addition, the timing of incurring costs can be significantly different than the timing for recovering costs, resulting in the need for a significant liquidity cushion.

Our hydroelectric generation was slightly below normal (based on a 70-year average) in 2009 and in eight of the past ten years. We cannot determine if lower than normal hydroelectric generation will continue in future years. When we have excess hydroelectric generation, its value varies with market prices and other displaceable resources. When hydroelectric generation is below normal, the cost to obtain power from other sources is generally higher. When hydroelectric generation is above normal, prices in the wholesale market are often depressed which can adversely impact our surplus sales revenues. 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."

Market prices for natural gas continue to be competitive compared to alternative fuel sources for customers, and we believe that natural gas should sustain its long-term market advantage over competing energy sources based on the levels of existing reserves and potential natural gas development in the future. Growth has occurred in the natural gas business in recent years due to increased demand for natural gas in new construction and conversions from competing space and water heating energy sources to natural gas.

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. This reduces the risk of these customers by-passing our system in the foreseeable future and minimizes the impact on our earnings.

We engage in wholesale sales and purchases of energy commodities and, accordingly, are subject to commodity price risk, credit risk and other risks associated with these activities.

COMMODITY PRICE RISK

In general, price risk is driven by fluctuation in the market price of the commodity needed, held or traded. The price of energy in wholesale markets is affected primarily by fundamental factors related to production costs and by other factors including weather and the resulting impact on retail loads. We hedge our exposure to price risk by making forward commitments for energy purchases and sales as further described under "Risk Management."

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 of or constraints on transmission facilities.

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

- amount of North American production and production capacity that can be delivered to our service areas,
- level of imports and exports, particularly from Canada by pipeline and to a growing extent by LNG,
- 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.

We have mechanisms in each regulatory jurisdiction that provide for recovery of the majority of the changes in our power and natural gas costs. The majority of power and natural gas costs exceeding the amount currently recovered through retail rates, excluding the ERM deadband (and other sharing components) in Washington, are deferred on our Consolidated Balance Sheets for the opportunity for recovery through future retail rates. These deferred power and natural gas costs are subject to review for prudence and recoverability and as such certain deferred costs may be disallowed by the respective regulatory agencies.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as assets or liabilities at market 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 presented as a net asset or (liability) as of December 31, 2009 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
2010	$ 5,143	$ (1,513)	$ (3,335)	$ (2,877)	$ 209	$ 35	$ (5,992)	—
2011	5,899	332	(889)	—	(193)	84	(679)	—
2012	5,481	—	(595)	—	(321)	—	—	—
2013	5,195	—	(59)	—	(324)	—	—	—
2014	4,979	—	—	—	(453)	—	—	—
Thereafter	30,548	—	—	—	(6,393)	—	—	—

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

Should a counterparty, customer or supplier 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 clearing arrangements that essentially eliminate 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, defaults by our counterparties periodically occur.

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 unsettled net positions and future obligations by counterparties to pay us or deliver to us warrant.

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

- electric utilities,
- electric generators and transmission providers,
- natural gas producers and pipelines,
- financial institutions, and
- energy marketing and trading companies.

In addition, 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 the exposure that counterparties perceive related to our ability to perform deliveries and settlement under physical and financial energy contracts. These counterparties may seek assurances of performance 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.

Credit risks related to our retail customer base include the extent to which customers do not pay or are slow to pay for energy we have delivered to them. We are allowed to recover normal credit losses in retail rates but economic conditions for our customers may result in unrecovered credit losses. We also extend credit (generally for up to five years) in certain circumstances to construction developers for the cost of utility infrastructure investment. The infrastructure costs are typically recovered when new customers begin receiving utility service but to the extent that customers do not connect as planned, we may carry credit risks with these developers.

We maintain credit reserves that are based on the evaluation of the credit risk of the overall portfolio. Based on our credit policies, exposures and credit reserves, we do not anticipate a materially adverse effect on our financial condition or results of operations as a result of counterparty nonperformance.

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 and by monitoring the effects of market changes in interest rates. 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 enter into financial derivative instruments, which may include interest rate swaps and U.S. Treasury lock agreements to manage and mitigate interest rate risk exposure. We did not have any interest rate swap contracts outstanding as of December 31, 2009.

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 $320.0 million and $75.0 million committed line of credit agreements have variable interest rates. The weighted average variable rate on outstanding short-term borrowings was 0.59 percent at December 31, 2009.

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, 2009 (dollars in thousands):

	2010	2011	2012	2013	2014	Thereafter	Total	Fair Value
Fixed rate long-term debt	$ 35,000	—	$ 7,000	$ 75,000	—	$ 955,100	$ 1,072,100	$ 1,079,857
Weighted average interest rate	7.67%	—	7.37%	6.58%	—	5.76%	5.89%	
Variable rate long-term debt to affiliated trusts	—	—	—	—	—	$ 51,547	$ 51,547	$ 43,534
Weighted average interest rate	—	—	—	—	—	1.22%	1.22%	

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. In early 2009, we implemented a process to 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, 2009, we had a current derivative liability for foreign currency hedges of less than $0.1 million included in other current liabilities on the Consolidated Balance Sheet. As of December 31, 2009, we had entered into 24 Canadian currency forward contracts with a notional amount of $10.2 million ($10.6 million Canadian).

RISK MANAGEMENT

We use a variety of techniques to manage risks for energy resources and wholesale energy market activities. We have an energy resources risk policy and control procedures to manage these risks, both qualitative and quantitative. Our Risk Management Committee 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 risk assessment and risk management policies, including the Company's material financial and accounting risk exposures and the steps management has undertaken to control them. Our Risk Management Committee reviews the status of risk exposures through regular reports and meetings and it monitors compliance with our risk management policy and control procedures. 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 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.

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 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. Effective January 1, 2010, the natural gas-fired Lancaster power purchase agreement was added to our utility resource portfolio, with the potential to significantly increase the extent of transactions for natural gas fuel hedging and plant optimization.

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, particularly in consideration of the national economic conditions with resultant financial stress among energy market participants. 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 36 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.

Further information for derivatives and fair values is disclosed at "Note 7 of the Notes to Consolidated Financial Statements" and "Note 20 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, 2009 and 2008, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2009. 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

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, 2009, 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 26, 2010, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 26, 2010

CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation
For the Years Ended December 31,
Dollars in thousands, except per share amounts

	2009	2008	2007
Operating Revenues:			
Utility revenues	$ 1,395,201	$ 1,572,664	$ 1,288,363
Non-utility energy marketing and trading revenues	24,436	25,225	61,541
Other non-utility revenues	92,928	78,874	67,853
Total operating revenues	1,512,565	1,676,763	1,417,757
Operating Expenses:			
Utility operating expenses:			
Resource costs	799,539	1,031,989	780,998
Other operating expenses	229,907	206,528	198,778
Depreciation and amortization	93,783	87,845	86,091
Taxes other than income taxes	76,583	72,057	72,443
Non-utility operating expenses:			
Resource costs	23,408	23,553	68,676
Other operating expenses	82,695	65,093	67,783
Depreciation and amortization	5,992	4,787	4,559
Total operating expenses	1,311,907	1,491,852	1,279,328
Income from operations	200,658	184,911	138,429
Other Income (Expense):			
Interest expense	(65,077)	(73,446)	(79,142)
Interest expense to affiliated trusts	(1,957)	(6,141)	(7,298)
Capitalized interest	545	4,612	3,864
Regulatory disallowance of unamortized debt repurchase costs	—	—	(3,850)
Other income — net	802	10,446	11,058
Total other income (expense) — net	(65,687)	(64,529)	(75,368)
Income before income taxes	134,971	120,382	63,061
Income taxes	46,323	45,625	24,334
Net income	88,648	74,757	38,727
Less: Net income attributable to noncontrolling interests	(1,577)	(1,137)	(252)
Net income attributable to Avista Corporation	$ 87,071	$ 73,620	$ 38,475
Weighted-average common shares outstanding (thousands), basic	54,694	53,637	52,796
Weighted-average common shares outstanding (thousands), diluted	54,942	54,028	53,263
Earnings per common share attributable to Avista Corporation (Note 22):			
Basic	$ 1.59	$ 1.37	$ 0.73
Diluted	$ 1.58	$ 1.36	$ 0.72
Dividends paid per common share	$ 0.810	$ 0.690	$ 0.595

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

	2009	2008	2007
Net income	$ 88,648	$ 74,757	$ 38,727
Other Comprehensive Income (Loss):			
Foreign currency translation adjustment	—	—	1,010
Reclassification adjustment for foreign currency translation adjustment included in loss on sale of contracts	—	—	(2,379)
Unrealized losses on interest rate swap agreements — net of taxes of $(2,063) and $(1,874), respectively	—	(3,831)	(3,480)
Reclassification adjustment for realized losses on interest rate swap agreements deferred as a regulatory asset (included in long-term debt) — net of taxes of $5,738	—	10,657	—
Change in unfunded benefit obligation for pension plan — net of taxes of $2,015, $3,602 and $1,642, respectively	3,742	6,690	3,050
Unrealized losses on derivative commodity instruments — net of taxes of $(324)	—	—	(602)
Reclassification adjustment for realized gains on derivative commodity instruments included in net income — net of taxes of $(136)	—	—	(253)
Reclassification adjustment for realized losses on derivative commodity instruments included in loss on sale of contracts, net of taxes of $464	—	—	862
Total other comprehensive income (loss)	3,742	13,516	(1,792)
Comprehensive income	92,390	88,273	36,935
Comprehensive income attributable to noncontrolling interests	(1,577)	(1,137)	(252)
Comprehensive income attributable to Avista Corporation	$ 90,813	$ 87,136	$ 36,683

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS

Avista Corporation
As of December 31,
Dollars in thousands

	2009	2008
Assets:		
Current Assets:		
Cash and cash equivalents	$ 37,035	$ 24,313
Accounts and notes receivable-less allowances of $42,928 and $45,062	210,645	218,846
Utility energy commodity derivative assets	7,757	11,234
Regulatory asset for utility derivatives	8,330	60,229
Funds held for customers	51,648	59,095
Materials and supplies, fuel stock and natural gas stored	37,282	53,526
Deferred income taxes	34,473	18,561
Income taxes receivable	16,438	22,769
Other current assets	15,315	13,654
Total current assets	418,923	482,227
Net Utility Property:		
Utility plant in service	3,549,658	3,343,535
Construction work in progress	60,055	77,487
Total	3,609,713	3,421,022
Less: Accumulated depreciation and amortization	1,002,702	928,831
Total net utility property	2,607,011	2,492,191
Other Property and Investments:		
Investment in exchange power-net	23,683	26,133
Investment in affiliated trusts	11,547	13,403
Goodwill	24,718	21,132
Other property and investments-net	77,590	78,208
Total other property and investments	137,538	138,876
Deferred Charges:		
Regulatory assets for deferred income tax	97,945	115,005
Regulatory assets for pensions and other postretirement benefits	141,085	172,278
Other regulatory assets	109,825	85,112
Non-current utility energy commodity derivative assets	45,483	49,313
Power deferrals	27,771	57,607
Other deferred charges	21,378	38,138
Total deferred charges	443,487	517,453
Total assets	$ 3,606,959	$ 3,630,747

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS (CONTINUED)

Avista Corporation
As of December 31,
Dollars in thousands

	2009	2008
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 160,861	$ 176,116
Customer fund obligations	51,648	59,095
Current portion of long-term debt	35,189	17,207
Short-term borrowings	92,700	252,200
Utility energy commodity derivative liabilities	16,087	71,463
Natural gas deferrals	39,952	18,646
Other current liabilities	106,980	90,268
Total current liabilities	503,417	684,995
Long-term debt	1,036,149	809,258
Long-term debt to affiliated trusts	51,547	113,403
Other Non-Current Liabilities and Deferred Credits:		
Regulatory liability for utility plant retirement costs	217,176	213,747
Non-current regulatory liability for utility derivatives	42,611	42,172
Pensions and other postretirement benefits	123,281	184,588
Deferred income taxes	494,666	488,940
Other non-current liabilities and deferred credits	52,665	56,915
Total other non-current liabilities and deferred credits	930,399	986,362
Total liabilities	2,521,512	2,594,018
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Redeemable Noncontrolling Interests	34,833	39,846
Equity:		
Avista Corporation Stockholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 54,836,781 and 54,487,574 shares outstanding	778,647	774,986
Accumulated other comprehensive loss	(2,350)	(6,092)
Retained earnings	274,990	227,989
Total Avista Corporation stockholders' equity	1,051,287	996,883
Noncontrolling Interests	(673)	—
Total equity	1,050,614	996,883
Total liabilities and equity	$ 3,606,959	$ 3,630,747

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

	2009	2008	2007
Operating Activities:			
Net income	$ 88,648	$ 74,757	$ 38,727
Non-cash items included in net income:			
Depreciation and amortization	99,775	92,632	90,650
Provision (benefit) for deferred income taxes	13,853	44,161	(7,369)
Power and natural gas cost amortizations, net of deferrals	51,359	45,836	19,630
Regulatory disallowance of unamortized debt repurchase costs	—	—	3,850
Amortization of debt expense	5,673	4,673	6,345
Unrealized loss on energy commodity derivatives	—	—	24,594
Loss on sale of Avista Energy assets	—	—	4,254
Equity-related AFUDC	(3,078)	(5,692)	(4,736)
Other	31,503	25,995	9,773
Payments for settlements with Coeur d'Alene Tribe	(12,000)	(25,187)	—
Contributions to defined benefit pension plan	(48,000)	(28,000)	(15,000)
Changes in working capital components:			
Accounts and notes receivable	14,659	(116,714)	180,488
Materials and supplies, fuel stock and natural gas stored	16,245	(18,541)	4,522
Deposits with counterparties	—	—	79,477
Other current assets	(3,528)	(10,494)	7,589
Accounts payable	(18,444)	47,669	(170,478)
Deposits from counterparties	3,000	(12,290)	(28,983)
Other current liabilities	19,116	(3,427)	8,308
Net cash provided by operating activities	258,781	115,378	251,641
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(205,384)	(219,239)	(205,811)
Other capital expenditures	(3,120)	(3,459)	(3,280)
Purchase of auction rate investment securities	—	—	(130,000)
Sale of auction rate investment securities	—	—	130,000
Decrease in restricted cash	—	4,068	25,834
Purchase of subsidiary noncontrolling interest	(5,450)	(6,624)	—
Cash paid by subsidiary for acquisition, net of cash received	(8,572)	(1,440)	—
Decrease in funds held for customers	8,507	30,790	249
Proceeds from asset sales	129	7,998	441
Other	(1,712)	2,561	(3,761)
Net cash used in investing activities	(215,602)	(185,345)	(186,328)

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (CONTINUED)

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

	2009	2008	2007
Financing Activities:			
Net increase (decrease) in short-term borrowings	$ (159,500)	$ 252,200	$ (4,000)
Proceeds from issuance of long-term debt	249,425	296,165	—
Redemption and maturity of long-term debt	(17,266)	(403,856)	(26,738)
Redemption of long-term debt to affiliated trusts	(61,856)	—	—
Long-term debt and short-term borrowing issuance costs	(3,726)	(5,024)	(165)
Cash received (paid) in interest rate swap agreements	10,776	(16,395)	—
Redemption of preferred stock	—	—	(26,250)
Issuance of common stock	2,622	28,565	4,977
Cash dividends paid	(44,360)	(37,071)	(31,451)
Decrease in customer fund obligations	(8,507)	(30,790)	(249)
Other	1,935	(1,353)	2,160
Net cash provided by (used in) financing activities	(30,457)	82,441	(81,716)
Net increase (decrease) in cash and cash equivalents	12,722	12,474	(16,403)
Cash and cash equivalents at beginning of year	24,313	11,839	28,242
Cash and cash equivalents at end of year	$ 37,035	$ 24,313	$ 11,839
Supplemental Cash Flow Information:			
Cash paid during the year:			
Interest	$ 58,756	$ 76,620	$ 79,112
Income taxes	22,695	10,004	29,367
Non-cash financing and investing activities:			
Accounts payable for capital expenditures	8,404	10,509	10,620
Redeemable noncontrolling interests	(400)	21,362	13,978
Issuance of stock by subsidiary for acquisition	—	37,000	—

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF EQUITY

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

	Common Stock Shares	Common Stock Amount	Accumulated Other Compre-hensive Income (Loss)	Retained Earnings	Total Avista Corporation Stock-holders' Equity	Non-Controlling Interests	Total Equity	Redeemable Non-Controlling Interests
Balance as of January 1, 2007	52,514,326	$ 715,620	$ (17,816)	$ 216,721	$ 914,525	$ 733	$ 915,258	$ —
Net income				38,475	38,475		38,475	252
Equity compensation expense		2,720			2,720		2,720	
Issuance of common stock through equity compensation plans	281,224	2,559			2,559		2,559	
Issuance of common stock through Employee Investment Plan (401-K)	14,685	329			329		329	
Issuance of common stock through Dividend Reinvestment Plan	98,778	2,158			2,158		2,158	
Common stock issuance costs		(69)			(69)		(69)	
Other comprehensive loss			(1,792)		(1,792)		(1,792)	
Reclassification of preferred stock issuance costs		1,334		(1,334)	—		—	
Cash dividends paid (common stock)				(31,451)	(31,451)		(31,451)	
Equity transactions of consolidated subsidiaries		2,282			2,282		2,282	
Valuation adjustments and other noncontrolling interests activity				(11,377)	(11,377)	(733)	(12,110)	14,588
Other				(4,393)	(4,393)		(4,393)	
Balance as of December 31, 2007	52,909,013	$ 726,933	$ (19,608)	$ 206,641	$ 913,966	$ —	$ 913,966	$ 14,840

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF EQUITY (CONTINUED)

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

	Common Stock Shares	Common Stock Amount	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Avista Corporation Stockholders' Equity	Non-Controlling Interests	Total Equity	Redeemable Non-Controlling Interests
Balance as of January 1, 2008	52,909,013	$ 726,933	$ (19,608)	$ 206,641	$ 913,966	$ —	$ 913,966	$ 14,840
Net income				73,620	73,620		73,620	1,137
Equity compensation expense		2,600			2,600		2,600	
Issuance of common stock through equity compensation plans	697,257	9,326			9,326		9,326	
Issuance of common stock through Employee Investment Plan (401-K)	15,361	311			311		311	
Issuance of common stock through Dividend Reinvestment Plan	115,943	2,328			2,328		2,328	
Issuance of common stock	750,000	16,599			16,599		16,599	
Other comprehensive income			13,516		13,516		13,516	
Cash dividends paid (common stock)				(37,071)	(37,071)		(37,071)	
Equity transactions of consolidated subsidiaries		16,889			16,889		16,889	
Purchase of subsidiary noncontrolling interests								(6,624)
Valuation adjustments and other noncontrolling interests activity				(15,201)	(15,201)		(15,201)	30,493
Balance as of December 31, 2008	54,487,574	$ 774,986	$ (6,092)	$ 227,989	$ 996,883	$ —	$ 996,883	$ 39,846

The Accompanying Notes are an Integral Part of These Statements.

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

	Common Stock Shares	Common Stock Amount	Accumulated Other Compre-hensive Income (Loss)	Retained Earnings	Total Avista Corporation Stock-holders' Equity	Non-Controlling Interests	Total Equity	Redeemable Non-Controlling Interests
Balance as of January 1, 2009	54,487,574	$ 774,986	$ (6,092)	$ 227,989	$ 996,883	$ —	$ 996,883	$ 39,846
Net income (loss)				87,071	87,071	(295)	86,776	1,872
Equity compensation expense		2,711			2,711		2,711	
Issuance of common stock through equity compensation plans	343,498	2,666			2,666		2,666	
Issuance of common stock through Employee Investment Plan (401-K)	4,309	71			71		71	
Issuance of common stock through Dividend Reinvestment Plan	1,400	26			26		26	
Common stock issuance costs		(141)			(141)		(141)	
Other comprehensive income			3,742		3,742		3,742	
Cash dividends paid (common stock)				(44,360)	(44,360)		(44,360)	
Equity transactions of consolidated subsidiaries		(1,672)			(1,672)		(1,672)	
Purchase of subsidiary noncontrolling interests								(5,450)
Valuation adjustments and other noncontrolling interests activity				4,290	4,290		4,290	(1,435)
Other					—	(378)	(378)	
Balance as of December 31, 2009	54,836,781	$ 778,647	$ (2,350)	$ 274,990	$ 1,051,287	$ (673)	$ 1,050,614	$ 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 including Avista Energy, Inc. (Avista Energy) and Advantage IQ, Inc. (Advantage IQ), a 74 percent owned subsidiary as of December 31, 2009. Avista Energy was an electricity and natural gas marketing, trading and resource management business. On June 30, 2007, Avista Energy completed the sale of substantially all of its contracts and ongoing operations. See Note 3 for further information. Advantage IQ is a provider of facility information and cost management services for multi-site customers throughout North America. See Note 27 for business segment information.

ACCOUNTING STANDARDS CODIFICATION

In June 2009, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 168, "The Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles — a replacement of FASB Statement No. 162." This statement replaces all previously issued accounting standards and establishes the FASB Accounting Standards Codification (ASC). The ASC is the single source of authoritative nongovernmental accounting principles generally accepted in the United States of America (U.S. GAAP) and is effective for all interim and annual periods ending after September 15, 2009. All existing accounting standards documents were superseded. All other accounting literature not included in the ASC is considered nonauthoritative. The adoption of the ASC did not have any impact on the Company's financial condition, results of operations and cash flows, as the ASC did not change existing U.S. GAAP. The adoption of the ASC only resulted in changes to the Company's financial statement disclosure references. In order to facilitate the transition to the ASC, the Company has elected to show references to U.S. GAAP within this report on Form 10-K prior to the ASC along with a parenthetical ASC reference.

BASIS OF REPORTING

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries, including Advantage IQ 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 8).

USE OF ESTIMATES

The preparation of the consolidated financial statements in conformity with 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 by the FERC.

UTILITY REVENUES

Utility revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. 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 $89.6 million as of December 31, 2009 and $84.3 million (net of $11.4 million of unbilled receivables sold) as of December 31, 2008. See Note 6 for information related to the sale of accounts receivable. 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.

NON-UTILITY ENERGY MARKETING AND TRADING REVENUES

This category of revenues decreased significantly with the sale of substantially all of Avista Energy's contracts and ongoing operations on June 30, 2007. The majority of Avista Energy's contracts were accounted for as derivatives. The net margin on derivative commodity instruments held for trading is reported as non-utility energy marketing and trading revenues. Revenues from contracts that are not derivatives, as well as derivative commodity instruments not held for trading, are reported on a gross basis in non-utility energy marketing and trading revenues. Revenues from Canadian contracts through Avista Energy Canada, Ltd. (Avista Energy Canada), which were not held for trading, were reported on a gross basis in non-utility energy marketing and trading revenues, totaled $64.5 million in 2007. There were not any revenues from Avista Energy Canada in 2009 and 2008.

OTHER NON-UTILITY REVENUES

Service revenues from Advantage IQ are recognized in the period services are rendered. Setup fees are deferred and recognized over the term of the related customer contracts. Interest earnings on funds held for customers are an integral part of Advantage IQ's product offerings and are recognized in revenues as earned. Revenues from the other businesses are primarily derived from the operations of Advanced Manufacturing and Development and are recognized when the risk of loss transfers to the customer, which generally 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 2009, 2008 and 2007.

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 2.78 percent in 2009, 2.77 percent in 2008 and 2.89 percent in 2007.

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

- electric thermal production — 32 years,
- hydroelectric production — 74 years,
- electric transmission — 51 years,
- electric distribution — 41 years, and
- natural gas distribution property — 53 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 $56.8 million in 2009, $53.9 million in 2008 and $51.0 million in 2007.

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. In accordance with the uniform system of accounts prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant and the debt related portion is credited currently 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 income-net. The Company generally is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a fair 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 generally does not occur until the related utility plant is placed in service and included in rate base. The effective AFUDC rate was 8.22 percent in 2009, 8.2 percent in 2008 and 9.11 percent in 2007. The Company's AFUDC rates do not exceed the maximum allowable rates as determined in accordance with the requirements of regulatory authorities.

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 of 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. See Note 23 for further information.

OTHER INCOME — NET

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

	2009	2008	2007
Interest income	$ 1,614	$ 3,262	$ 7,812
Interest on regulatory deferrals	2,935	3,671	4,369
Interest on income tax settlement	—	5,749	—
Equity-related AFUDC	3,078	5,692	4,736
Net gain (loss) on investments	(837)	(1,368)	445
Other expense	(6,877)	(7,394)	(6,585)
Other income	889	834	281
Total	$ 802	$ 10,446	$ 11,058

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 22 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):

	2009	2008	2007
Allowance as of the beginning of the year	$ 45,062	$ 42,582	$ 42,360
Additions expensed during the year	5,344	6,595	3,148
Net deductions	(7,478)	(4,115)	(2,926)
Allowance as of the end of the year	$ 42,928	$ 45,062	$ 42,582

MATERIALS AND SUPPLIES, FUEL STOCK AND NATURAL GAS STORED

Inventories of materials and supplies, fuel stock and natural gas stored are recorded at the lower of cost or market, primarily using the average cost method and consisted of the following as of December 31 (dollars in thousands):

	2009	2008
Materials and supplies	$ 20,281	$ 19,133
Fuel stock	4,294	3,673
Natural gas stored	12,707	30,720
Total	$ 37,282	$ 53,526

FUNDS HELD FOR CUSTOMERS AND CUSTOMER FUND OBLIGATIONS

In connection with the bill paying services, Advantage IQ collects funds from its customers and remits the funds to the appropriate utility or other service provider. The funds collected are invested and classified as funds held for customers and a related liability for customer fund obligations is recorded. Funds held for customers include cash and cash equivalent investments.

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. Costs of depreciable units of property retired plus costs of removal less salvage are 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 10). The Company had estimated retirement costs included as a regulatory liability on the Consolidated Balance Sheets of $217.2 million as of December 31, 2009 and $213.7 million as of December 31, 2008. These costs do not represent legal or contractual obligations.

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, 2009 for the other businesses and as of December 31, 2009 for Advantage IQ and determined that goodwill was not impaired at that time.

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

	Advantage IQ	Other	Accumulated Impairment Losses	Total
Balance as of December 31, 2007	$ —	$ 12,979	$ (7,733)	$ 5,246
Goodwill acquired during the year	15,886	—	—	15,886
Balance as of December 31, 2008	15,886	12,979	(7,733)	21,132
Goodwill acquired during the year	4,209	—	—	4,209
Adjustments	(623)	—	—	(623)
Balance as of the December 31, 2009	$ 19,472	$ 12,979	$ (7,733)	$ 24,718

The goodwill acquired in 2008 was primarily related to the Advantage IQ acquisition of Cadence Network, Inc. (Cadence Network) completed in July 2008 (see Note 5). The goodwill acquired in 2009 was related to Advantage IQ's acquisition of substantially all of the assets and liabilities of Ecos Consulting, Inc. (Ecos), a Portland, Oregon-based energy efficiency solutions provider. The adjustment to goodwill recorded in 2009 represents final purchase accounting adjustments for Advantage IQ's acquisition of Cadence Network based upon the completion of the review of the fair market values of relevant assets and liabilities identified as of the acquisition date.

OTHER INTANGIBLES

Other Intangibles primarily represent the amounts assigned to client relationships related to the Advantage IQ acquisition of Cadence Network in 2008 (estimated amortization period of 14 years) and Ecos in 2009 (estimated amortization period of 3 years), software development costs (estimated amortization period of 5 to 7 years) and other. Other Intangibles are included in other property and investments — net on the Consolidated Balance Sheets. Amortization expense related to Other Intangibles was $2.4 million for 2009, $1.1 million for 2008 and $0.7 million for 2007.

The gross carrying amount and accumulated amortization of Other Intangibles as of December 31, 2009 and 2008 are as follows (dollars in thousands):

	2009	2008
Client relationships	$ 10,259	$ 8,909
Software development costs	16,496	14,067
Other	1,371	570
Total other intangibles	28,126	23,546
Less accumulated amortization	(8,192)	(5,804)
Total other intangibles — net	$ 19,934	$ 17,742

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

	2010	2011	2012	2013	2014
Estimated amortization expense	$ 4,073	$ 3,789	$ 3,302	$ 2,693	$ 1,892

REGULATORY DEFERRED CHARGES AND CREDITS

The Company prepares its consolidated financial statements in accordance with the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (ASC 980) 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.

ASC 980 requires the Company to reflect the impact of regulatory decisions in its financial statements. ASC 980 requires 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 ASC 980 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.

The Company's primary regulatory assets include:

- power cost deferrals,
- investment in exchange power,
- regulatory asset for deferred income taxes,
- unamortized debt repurchase costs,
- assets offsetting net utility energy commodity derivative liabilities (see Note 7 for further information),
- expenditures for demand side management programs,
- expenditures for conservation programs,
- payments to the Coeur d'Alene Tribe for past water storage and the licensing of the Spokane River Project,

- certain expenditures for licensing hydroelectric generating facilities, and
- unfunded pensions and other postretirement benefits.

Regulatory assets without a specific line on the Consolidated Balance Sheets are included in other regulatory assets.

Regulatory liabilities include:

- utility plant retirement costs,
- natural gas deferrals, and
- liabilities offsetting net utility energy commodity derivative assets (see Note 7 for further information).

Regulatory liabilities without a specific line on the Consolidated Balance Sheets are included in other current liabilities and other non-current liabilities and deferred credits. See Note 26 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 Washington Utilities and Transportation Commission (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 beginning 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 primary 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

Represents the estimated fair value of redeemable stock and stock options of Advantage IQ issued under its employee stock incentive plan and to the previous owners of Cadence Network. See Notes 5 and 23 for further information.

ACCUMULATED OTHER COMPREHENSIVE LOSS

Accumulated other comprehensive loss, net of tax, consisted of the unfunded benefit obligation for pensions and other postretirement benefit plans as of December 31, 2009 and 2008.

NOTE 2. NEW ACCOUNTING STANDARDS

Effective January 1, 2008, the Company adopted the provisions of SFAS No. 157, "Fair Value Measurements" (ASC 820-10) related to its financial assets and liabilities and nonfinancial assets and liabilities measured at fair value on a recurring basis. In February 2008, the FASB issued Staff Position (FSP) No. 157-2, which deferred the effective date for certain portions of ASC 820-10 related to nonrecurring measurements of nonfinancial assets and liabilities. Effective January 1, 2009, the Company adopted those provisions of ASC 820-10. The adoption of the provisions of ASC 820-10 that became effective on January 1, 2008 and 2009, did not have a material impact on the Company's financial condition, results of operations and cash flows. However, the Company expanded disclosures for fair value measurements that became effective on January 1, 2008. There were no additional disclosures related to the provisions that became effective January 1, 2009. See Note 20 for the expanded disclosures.

Effective January 1, 2008 the Company adopted FSP FIN 39-1, "Amendment of FASB Interpretation No. 39" (ASC 210-20) that permits an entity to offset fair value amounts recognized for the right to reclaim or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. As of December 31, 2009 and 2008, the Company did not offset any fair value cash collateral receivables against net derivative positions. The fair value of cash collateral that was not offset in the Consolidated Balance Sheets was $3.2 million as of December 31, 2009 and $0.2 million as of December 31, 2008 (included in other current liabilities).

Effective January 1, 2009, the Company adopted SFAS No. 141(R), "Business Combinations" (ASC 805-10) that replaces previous accounting guidance for business combinations and addresses the accounting for all transactions or other events in which an entity obtains control of one or more businesses. This statement requires the acquiring entity in a business combination to recognize the assets acquired, the liabilities assumed, and any noncontrolling interest in the transaction at the acquisition date, measured at their fair values as of that date, with limited exceptions. The acquisition of Ecos was accounted for in accordance with the provisions of this statement, which did not have a material effect on the consolidated financial statements.

Effective January 1, 2009, the Company adopted SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB No. 51" (ASC 810-10). This statement amended previous accounting guidance to establish accounting and reporting standards for a noncontrolling (minority) interest in a subsidiary and for the deconsolidation of a subsidiary. This statement clarifies that a noncontrolling interest in a subsidiary is an ownership in the consolidated entity that should be reported as equity in the consolidated financial statements. The adoption of this statement had no material impact on the Company's financial condition and results of operations. However, it did impact the presentation and disclosure of noncontrolling interests in the Company's consolidated financial statements. The presentation and disclosure requirements were retrospectively applied to the consolidated financial statements. The Company included $(0.7) million of noncontrolling interests in equity as of December 31, 2009. Net income attributable to noncontrolling interests was $1.6 million for 2009, $1.1 million for 2008 and $0.3 million for 2007. The net income attributable to noncontrolling interests primarily relates to third party shareholders of Advantage IQ, who own approximately 26 percent of the common stock of Advantage IQ as of December 31, 2009. This ownership is reflected as $34.8 million of redeemable noncontrolling interests on the Consolidated Balance Sheets. In connection with the adoption of this statement, the Company has reclassified $39.8 million to redeemable noncontrolling interests as of December 31, 2008. This amount was previously included as $3.5 million of other current liabilities and $36.3 million of other non-current liabilities and deferred credits. Such corrections were not made to the quarterly Consolidated Balance Sheets and Consolidated Statements of Equity included in Form 10-Q for the quarters ended March 31, 2009, June 30, 2009 and September 30, 2009.

Effective January 1, 2009, the Company adopted SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities" (ASC 815-10) that requires disclosure of the fair value of derivative instruments and their gains and losses in a tabular format. The statement requires disclosure of derivative features that are related to credit risk. The Company expanded disclosures for derivatives and hedging activities. See Note 7 for the expanded disclosures.

Effective December 31, 2009, the Company adopted FSP FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets" (ASC 715-20) that amends FASB Statement No. 132(R) "Employers' Disclosures about Pensions and Other Postretirement Benefits" (ASC 715-20). This statement provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. The Company has expanded disclosures for its pension and other postretirement benefit plan assets in Note 11.

Effective June 30, 2009, the Company adopted FSP FAS 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" (ASC 820-65-10-4) that provides guidance for determining fair values of financial instruments for which there is no active market or when quoted prices may represent distressed transactions. The guidance includes a reaffirmation of the need to use judgment in certain circumstances and requires expanded disclosures surrounding equity and debt securities. The adoption of this FSP did not have an impact on the Company's financial condition, results of operations and cash flows.

Effective June 30, 2009, the Company adopted SFAS No. 165, "Subsequent Events" (ASC 855-10). This statement established principles and requirements for subsequent events related to: 1) the period after the balance sheet date during which management of a reporting entity shall evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; 2) the circumstances under which an entity shall recognize events or transactions occurring after the balance sheet date in its financial statements; and 3) the disclosures that an entity shall make about events or transactions that occurred after the balance sheet date. The Company evaluated subsequent events up to the filing of this Form 10-K on February 26, 2010 (the date the financial statements were issued).

In June 2009, the FASB issued SFAS No. 166, "Accounting for Transfers of Financial Assets an amendment of FASB Statement No. 140" (ASC 860). This statement amends certain provisions of SFAS No. 140 (ASC 860) related to accounting for transfers of financial assets and a transferor's continuing involvement in transferred financial assets. The Company was required to adopt this statement effective January 1, 2010. The Company is evaluating the impact this statement will have on its financial condition, results of operations and cash flows. In particular, the Company is evaluating its accounts receivable sales (see Note 6) to determine whether or not the transactions meet the criteria of sales of financial assets. If the transactions did not meet the criteria, the transactions would be accounted for as secured borrowings. As of December 31, 2009, the Company had not sold any accounts receivable under the revolving agreement. The Company will finalize its evaluation during the first quarter of 2010 to determine the impact of adoption, if any, on its financial condition, results of operations and cash flows.

In June 2009, the FASB issued SFAS No. 167, "Amendments to FASB Interpretation No. 46(R)" (ASC 810). This statement carries forward the scope of FASB Interpretation No. 46(R) (ASC 810), with the addition of entities previously considered qualifying special-purpose entities, as the concept of these entities was eliminated in SFAS No. 166 (ASC 860). The amendments will significantly affect the overall consolidation analysis of variable interest entities (VIE). The amendments will require the Company to reconsider previous conclusions relating to the consolidation of VIEs, including whether an entity is a VIE, whether the Company is the VIE's primary beneficiary, and what type of financial statement disclosures are required. The Company was required to adopt this statement effective January 1, 2010. The Company is evaluating the impact this statement will have on its financial condition, results of operations and cash flows. In particular, the Company is evaluating the potential consolidation of Spokane Energy LLC. This would add approximately $85 million of assets and liabilities (as of January 1, 2010 consisting primarily of a long-term contract receivable and non-recourse debt) to the Consolidated Balance Sheet, with no material effect on the Company's results of operations. In addition, the Company is evaluating certain long-term power purchase contracts under this guidance. The Company will finalize its evaluation during the first quarter of 2010 to determine the impact of adoption, if any, on its financial condition, results of operations and cash flows.

NOTE 3. DISPOSITION OF AVISTA ENERGY

On June 30, 2007, Avista Energy and Avista Energy Canada completed the sale of substantially all of their contracts and ongoing operations to Shell Energy North America (U.S.), L.P. (Shell Energy), formerly known as Coral Energy Holding, L.P., as well as to certain other subsidiaries of Shell Energy. Proceeds from the transaction included cash consideration for the net assets acquired by Shell Energy and the liquidation of the remaining net current assets of Avista Energy not sold to Shell Energy (primarily receivables, restricted cash and deposits with counterparties). The pre-tax net loss on the transaction was $4.3 million, which is included in non-utility other operating expenses in the Consolidated Statements of Income for 2007.

Certain assets of Avista Energy with a net book value of approximately $30 million were not sold or liquidated. These primarily include natural gas storage and deferred income tax assets. The Company expects that the natural gas storage will ultimately be transferred to Avista Utilities, subject to future regulatory approval. There is also a power purchase agreement, related to a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho (Lancaster Plant). The Lancaster Plant is owned by an unrelated third-party and all of the output from the plant is contracted to Avista Turbine Power, Inc. (an affiliate of Avista Energy) through 2026. The majority of the rights and obligations of the power purchase agreement were conveyed to Shell Energy through the end of 2009. The rights and obligations of power purchase agreement were conveyed to Avista Utilities in January 2010.

In connection with the transaction, on June 30, 2007, Avista Energy and its affiliates entered into an Indemnification Agreement with Shell Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Shell Energy each agree to provide indemnification of the other and the other's affiliates for certain events and matters described in the purchase and sale agreement and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the western energy markets in 2000 and 2001 (see Note 24), existing litigation, tax liabilities, and matters related to natural gas storage rights. In general, such indemnification is not required unless and until a party's claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy's obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of $30 million plus certain fees and expenses. The Guaranty will terminate April 30, 2011 except for claims made prior to termination. As of February 26, 2010, neither party has made any claims under the Indemnification Agreement or Guaranty.

NOTE 4. IMPAIRMENT OF ASSETS

During the third quarter of 2007, the Company recorded an impairment charge of $2.3 million for a turbine and related equipment, which is included in other operating expenses in the Consolidated Statements of Income. The Company originally planned to use the turbine in a regulated utility generation project. At the end of the third quarter of 2007, the Company reached a conclusion to sell the turbine and related equipment, which were classified as assets held for sale as of December 31, 2007, and included in other current assets on the Consolidated Balance Sheet. The impairment charge reduced the carrying value of the assets to the estimated fair value. The turbine was sold in 2008.

Pursuant to a settlement agreement in its Washington general rate case entered into in October 2007 and approved by the WUTC in December 2007, Avista Corp. agreed to write off $3.8 million of unamortized debt repurchase costs. This expense is reflected as regulatory disallowance of unamortized debt repurchase costs in the Consolidated Statements of Income. These costs were for premiums paid to repurchase debt prior to its scheduled maturity. In accordance with regulatory accounting practices, these premiums were recorded as a regulatory asset in unamortized debt expense on the Consolidated Balance Sheet and were being amortized over the average remaining maturity of outstanding debt.

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 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 is $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 20 for a discussion of the fair value hierarchy.

NOTE 5. ADVANTAGE IQ ACQUISITIONS

Effective July 2, 2008, Advantage IQ completed the acquisition of Cadence Network, a privately held, Cincinnati-based energy and expense management company. As consideration, the owners of Cadence Network received a 25 percent ownership interest in Advantage IQ. The total value of the transaction was $37 million.

The acquisition of Cadence Network was funded with the issuance of Advantage IQ common stock. Under the transaction agreement, the previous owners of Cadence Network can exercise a right to have their shares of Advantage IQ common stock redeemed during July 2011 or July 2012 if Advantage IQ is not liquidated through either an initial public offering or sale of the business to a third party. Their redemption rights expire July 31, 2012. The redemption price would be determined based on the fair market value of Advantage IQ at the time of the redemption election as determined by certain independent parties. Based on the estimated fair market value of Advantage IQ common stock held by the previous owners of Cadence Network, redeemable noncontrolling interests was $27.9 million as of December 31, 2009. Additionally, the certain minority shareholders and option holders of Advantage IQ have the right to put their shares back to Advantage IQ at their discretion. This redeemable noncontrolling interest was $6.9 million as of December 31, 2009 for the intrinsic value of stock options outstanding, as well as outstanding redeemable stock (refer to Note 23 for further information).

Advantage IQ's acquisition of Cadence Network was accounted for under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed were recorded at their respective estimated fair values as of the date of acquisition (July 2, 2008). The results of operations of Cadence Network are included in the consolidated financial statements beginning in the third quarter of 2008. Pro forma disclosures reflecting the effects of the acquisition of Cadence Network are not presented, as the acquisition is not material to Avista Corp.'s consolidated financial condition or results of operations.

On August 31, 2009, Advantage IQ acquired substantially all of the assets and liabilities of Ecos Consulting, Inc. (Ecos), a Portland, Oregon-based energy efficiency solutions provider for $8.9 million. The acquisition of Ecos was funded primarily through borrowings under Advantage IQ's committed credit agreement. Under the terms of the transaction, the assets and liabilities of Ecos were acquired by a wholly owned subsidiary of Advantage IQ.

Advantage IQ's acquisition of Ecos was accounted for under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed 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. Pro forma disclosures reflecting the effects of the acquisition of Ecos are not presented, as the acquisition is not material to Avista Corp.'s consolidated financial condition or results of operations.

NOTE 6. ACCOUNTS RECEIVABLE SALE

Avista Receivables Corporation (ARC) is a wholly owned, bankruptcy-remote subsidiary of Avista Corp. formed for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. Avista Corp., ARC and a third-party financial institution are parties to a Receivables Purchase Agreement, and on March 13, 2009 that agreement was amended to, among other things, extend the termination date to March 12, 2010. Under the Receivables Purchase Agreement, ARC can sell without recourse, and such financial institution will purchase, on a revolving basis, up to $85.0 million of those receivables. ARC is obligated to pay fees that approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. On a consolidated basis, the amount of such fees is included in other operating expenses of Avista Corp. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of Avista Corp.'s committed lines of credit (see Note 14). Based on calculations of eligible receivables, ARC had the ability to sell up to $85.0 million of receivables under this revolving agreement at each of December 31, 2009 and December 31, 2008. There were not any accounts receivable sold under this revolving agreement as of December 31, 2009 and $17.0 million were sold as of December 31, 2008.

NOTE 7. 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 management. The Audit Committee of the Company's Board of Directors periodically reviews and discusses risk assessment and risk management policies, including the Company's material financial and accounting risk exposures and the steps management has undertaken to control them.

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

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

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

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

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. Forward natural gas contracts are typically for monthly delivery periods. 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 gas supply requirements unhedged for purchase in short-term and spot markets. Natural gas resource optimization activities include:

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

Derivatives are recorded as either assets or liabilities on the balance sheet 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 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 Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rates cases.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as assets or liabilities at market value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives under ASC 815 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 the underlying energy commodity derivative volumes as of December 31, 2009 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
2010	760	568	26,699	1,210	1,381	49	5,051	—
2011	401	138	10,477	—	286	31	467	—
2012	366	—	4,128	—	287	—	—	—
2013	368	—	1,575	—	286	—	—	—
2014	366	—	—	—	286	—	—	—
Thereafter	1,694	—	—	—	1,303	—	—	—

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. In early 2009, Avista Utilities implemented a process to 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 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. As of December 31, 2009, the Company had a current derivative liability for foreign currency hedges of less than $0.1 million included in other current liabilities on the Consolidated Balance Sheet. As of December 31, 2009, the Company had entered into 24 Canadian currency forward contracts with a notional amount of $10.2 million ($10.6 million Canadian).

INTEREST RATE SWAP AGREEMENTS

Avista Corp. enters into forward-starting interest rate swap agreements to manage the risk associated with changes in interest rates and the impact on future interest payments. These interest rate swap agreements relate to the interest payments for anticipated debt issuances. These interest rate swap agreements are considered economic hedges against fluctuations in future cash flows associated with changes in interest rates. In September 2009, the Company cash settled interest rate swap contracts (notional amount of $200.0 million) and received a total of $10.8 million. The interest rate swap contracts were settled concurrently with the issuance of $250.0 million of First Mortgage Bonds (see Note 15). These settlements of the interest rate swaps were deferred as a regulatory liability (included as part of long-term debt) and will be amortized as a component of interest expense over the life of the associated debt issued in accordance with regulatory accounting practices. The Company did not have any interest rate swap contracts outstanding as of December 31, 2009.

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, 2009 (in thousands):

		Fair Value		
Derivative	Balance Sheet Location	Asset	Liability	Net Asset (Liability)
Foreign currency contracts	Other current liabilities	$ —	$ (50)	$ (50)
Commodity contracts	Current utility energy commodity derivative assets	8,976	(1,219)	7,757
Commodity contracts	Non-current utility energy commodity derivative assets	53,765	(8,282)	45,483
Commodity contracts	Current utility energy commodity derivative liabilities	5,783	(21,870)	(16,087)
Commodity contracts	Other non-current liabilities and deferred credits	650	(3,521)	(2,871)
Total derivative instruments recorded on the balance sheet		$ 69,174	$ (34,942)	$ 34,232

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 adverse 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 minimize capital requirements.

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, 2009 was $11.8 million. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2009, the Company would be required to post $3.4 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. Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established.

Credit risk includes potential counterparty default due to circumstances:

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

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

The Company seeks to mitigate credit risk by:

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

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

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

- electric utilities,
- electric generators and transmission providers,
- natural gas producers and pipelines,
- financial institutions, and
- energy marketing and trading companies.

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

As is common industry practice, Avista Utilities maintains margin agreements with certain counterparties. 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. Margin calls are periodically made and/or received by Avista Utilities. Negotiating for collateral in the form of cash, letters of credit, or performance guarantees is common industry practice.

Cash deposits from counterparties totaled $3.2 million as of December 31, 2009 and $0.2 million as of December 31, 2008. These funds were held by Avista Utilities to mitigate the potential impact of counterparty default risk. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of non-cash collateral.

NOTE 8. 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 was $334.8 million and accumulated depreciation was $209.6 million as of December 31, 2009. The Company's share of utility plant in service for Colstrip was $330.9 million and accumulated depreciation was $204.0 million as of December 31, 2008.

NOTE 9. 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):

	2009	2008
Avista Utilities:		
Electric production	$ 1,060,495	$ 1,031,925
Electric transmission	471,686	460,398
Electric distribution	1,023,541	958,770
Electric intangible [1]	3,969	3,474
Electric construction work-in-progress (CWIP) and other	165,883	146,818
Electric total	2,725,574	2,601,385
Natural gas underground storage	35,390	36,355
Natural gas distribution	630,720	599,596
Natural gas intangible [1]	23,910	23,692
Natural gas CWIP and other	27,044	26,452
Natural gas total	717,064	686,095
Common plant CWIP and other	133,696	108,406
Common intangible [1]	33,379	25,136
Common total	167,075	133,542
Total Avista Utilities	3,609,713	3,421,022
Advantage IQ [2]	27,513	23,878
Other [2]	41,913	45,041
Total	$ 3,679,139	$ 3,489,941

(1) *Intangible plant primarily consists of the excess of the fair value of natural gas utility plant acquired in 1991, software costs, and hydroelectric licensing costs.*

(2) *Included in other property and investments-net on the Consolidated Balance Sheets.*

NOTE 10. 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):

	2009	2008	2007
Asset retirement obligation at beginning of year	$ 4,208	$ 3,990	$ 4,810
New liability recognized	—	—	—
Liability adjustment due to revision in estimated cash flows	—	—	(1,063)
Liability settled	(499)	(29)	(71)
Accretion expense	262	247	314
Asset retirement obligation at end of year	$ 3,971	$ 4,208	$ 3,990

NOTE 11. 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 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 $48 million in cash to the pension plan in 2009, $28 million in 2008 and $15 million in 2007. The Company expects to contribute $21 million to the pension plan in 2010.

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 $18.6 million in 2010, $19.4 million in 2011, $20.5 million in 2012, $21.7 million in 2013 and $23.0 million in 2014. For the ensuing five years (2015 through 2019), the Company expects that benefit payments under the pension plan and the SERP will total $136.3 million.

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.

In 2009, the Company reviewed the mortality table utilized in the actuarial calculations. The Company determined that the RP-2000 combined healthy mortality tables for males and females should be replaced with the RP-2000 combined healthy mortality tables for males and females projected to 2010 using scale AA. The change resulted in an increase of $6.6 million to the pension benefit obligation as of December 31, 2009.

In 2008, the rates at which participants are assumed to retire by age were analyzed based upon historical trends and future projections. The Company revised the rates to assume that a greater percentage of participants would retire between the ages of 55 and 65. The assumed rates were revised to range from 5 percent to 40 percent and 100 percent at age 65. The previous rates ranged from 2 percent to 30 percent and 100 percent at age 65. The change resulted in an increase of $11.0 million to the pension benefit obligation as of December 31, 2008.

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 twenty years, beginning in 1993.

The Company established a Health Reimbursement Arrangement to provide employees with tax-advantaged funds to pay for allowable medical expenses upon retirement. The amount earned by the employee is fixed on the retirement date based on employees' 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 be $4.1 million in 2010, $3.9 million in 2011, $3.7 million in 2012, $3.6 million in 2013 and $3.5 million in 2014. For the ensuing five years (2015 through 2019), the Company expects that benefit payments under other postretirement benefit plans will total $16.4 million. The Company expects to contribute $4.1 million to other postretirement benefit plans in 2010, 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, 2009 and 2008 and the components of net periodic benefit costs for the years ended December 31, 2009, 2008 and 2007 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2009	2008	2009	2008
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 353,572	$ 323,090	$ 38,953	$ 34,352
Service cost	10,496	10,209	803	772
Interest cost	21,770	20,812	2,364	2,371
Actuarial loss	9,610	17,041	1,676	5,611
Transfer of accrued vacation	—	—	98	365
Benefits paid	(17,213)	(17,580)	(4,334)	(4,518)
Benefit obligation as of end of year	$ 378,235	$ 353,572	$ 39,560	$ 38,953
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 190,637	$ 242,561	$ 16,048	$ 22,718
Actual return on plan assets	50,053	(63,575)	4,346	(6,670)
Employer contributions	48,000	28,000	—	—
Benefits paid	(15,958)	(16,349)	—	—
Fair value of plan assets as of end of year	$ 272,732	$ 190,637	$ 20,394	$ 16,048
Funded status	$ (105,503)	$ (162,935)	$ (19,166)	$ (22,905)
Unrecognized net actuarial loss	126,926	160,280	15,772	18,357
Unrecognized prior service cost	1,790	2,444	(1,303)	(1,452)
Unrecognized net transition obligation	—	—	1,516	2,021
Prepaid (accrued) benefit cost	23,213	(211)	(3,181)	(3,979)
Additional liability	(128,716)	(162,724)	(15,985)	(18,926)
Accrued benefit liability	$ (105,503)	$ (162,935)	$ (19,166)	$ (22,905)
Accumulated pension benefit obligation	$ 294,649	$ 307,413	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 18,377	$ 18,821
For fully eligible employees			$ 9,290	$ 8,903
For other participants			$ 11,893	$ 11,229
Included in accumulated comprehensive loss (income) (net of tax):				
Unrecognized net transition obligation	$ —	$ —	$ 985	$ 1,313
Unrecognized prior service cost	1,163	1,589	(847)	(943)
Unrecognized net actuarial loss	82,502	104,182	10,252	11,932
Total	83,665	105,771	10,390	12,302
Less regulatory asset	(80,041)	(98,850)	(11,664)	(13,131)
Accumulated other comprehensive loss (income)	$ 3,624	$ 6,921	$ (1,274)	$ (829)

	Pension Benefits		Other Post-retirement Benefits	
	2009	2008	2009	2008
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	6.29%	6.25%	6.00%	6.25%
Discount rate for annual expense	6.25%	6.34%	6.25%	6.20%
Expected long-term return on plan assets	8.50%	8.50%	8.50%	8.50%
Rate of compensation increase	4.65%	4.72%		
Medical cost trend pre-age 65 — initial			8.50%	9.00%
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			8.50%	9.00%
Medical cost trend post-age 65 — ultimate			6.00%	6.00%
Ultimate medical cost trend year post-age 65			2015	2015

	2009	2008	2007	2009	2008	2007
Components of net periodic benefit cost:						
Service cost	$ 10,496	$ 10,209	$ 10,694	$ 803	$ 772	$ 672
Interest cost	21,770	20,812	19,161	2,364	2,371	2,159
Expected return on plan assets	(17,612)	(21,138)	(19,217)	(1,364)	(1,931)	(1,775)
Transition obligation recognition	—	—	—	505	505	505
Amortization of prior service cost	654	654	653	(149)	(149)	—
Net loss recognition	10,539	3,345	2,978	1,279	575	193
Net periodic benefit cost	$ 25,847	$ 13,882	$ 14,269	$ 3,438	$ 2,143	$ 1,754

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 plan, 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 of December 31, 2009 and 2008 as indicated in the table below:

	2009	2008
Equity securities	51%	50%
Debt securities	31%	30%
Real estate	5%	5%
Absolute return	10%	12%
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:

- current cost of reproducing a property less deterioration and functional economic obsolescence,
- capitalization of the property's net earnings power, and
- value indicated by recent sales of comparable properties in the market.

The market-related value of pension plan assets was determined as of December 31, 2009 and 2008.

The following table discloses by level within the fair value hierarchy (refer to Note 20 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2009 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 19	$ —	$ —	$ 19
Mutual funds:				
Fixed income securities	70,924	—	—	70,924
U.S. equity securities	87,562	—	—	87,562
International equity securities	46,548	—	—	46,548
Absolute return (1)	11,671	—	—	11,671
Commodities (2)	5,870	—	—	5,870
Common/collective trusts:				
Fixed income securities	—	14,840	—	14,840
U.S. equity securities	—	11,070	—	11,070
Absolute return (1)	—	—	844	844
Real estate	—	—	6,029	6,029
Partnership/closely held investments:				
Absolute return (1)	—	—	15,794	15,794
Private equity funds (3)	—	—	1,561	1,561
Total	$ 222,594	$ 25,910	$ 24,228	$ 272,732

(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 several 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, 2009 (dollars in thousands):

	Common/collective trusts		Partnership/closely held investments	
	Absolute return	Real estate	Absolute return	Private equity funds
Balance, as of January 1, 2009	$ 2,351	$ 11,987	$ 13,983	$ 1,316
Realized gains (losses)	(415)	520	—	3
Unrealized gains (losses)	(21)	(4,310)	1,811	223
Purchases (sales), net	(1,071)	(2,168)	—	19
Balance, as of December 31, 2009	$ 844	$ 6,029	$ 15,794	$ 1,561

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 market-related value of other postretirement plan assets was determined as of December 31, 2009 and 2008.

The following table discloses by level within the fair value hierarchy (refer to Note 20 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2009 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 96	$ —	$ —	$ 96
Mutual funds:				
Debt securities	7,742	—	—	7,742
U.S. equity securities	5,927	—	—	5,927
International equity securities	5,077	—	—	5,077
Debt securities	25	—	—	25
U.S. equity securities	1,456	—	—	1,456
International equity securities	71	—	—	71
Total	$ 20,394	$ —	$ —	$ 20,394

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, 2009 by $2.1 million and the service and interest cost by $0.2 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, 2009 by $1.9 million and the service and interest cost by $0.2 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 $4.7 million in 2009, $4.8 million in 2008 and $5.1 million in 2007.

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. At December 31, 2009 and 2008, there were deferred compensation assets of $9.4 million and $8.8 million included in other property and investments-net and corresponding deferred compensation liabilities of $9.4 million and $8.8 million included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets.

NOTE 12. ACCOUNTING FOR INCOME TAXES

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

	2009	2008	2007
Taxes currently provided	$ 32,470	$ 1,464	$ 31,703
Deferred income tax expense (benefit)	13,853	44,161	(7,369)
Total income tax expense	$ 46,323	$ 45,625	$ 24,334

A reconciliation of federal income taxes derived from statutory federal tax rates (35 percent in 2009, 2008 and 2007) 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):

	2009	2008	2007
Federal income taxes at statutory rates	$ 47,182	$ 41,676	$ 21,983
Increase (decrease) in tax resulting from:			
Tax effect of regulatory treatment of utility plant differences	1,858	2,260	4,526
State income tax expense	2,746	1,617	732
Preferred dividends	—	—	479
Settlement of prior year tax returns and adjustment of tax reserves	(2,726)	2,505	1,019
Manufacturing deduction	(1,091)	(991)	(1,738)
Kettle Falls tax credit	(1,622)	(1,773)	(2,645)
Other	(24)	331	(22)
Total income tax expense	$ 46,323	$ 45,625	$ 24,334

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):

	2009	2008
Deferred income tax assets:		
Allowance for doubtful accounts	$ 11,872	$ 12,618
Reserves not currently deductible	6,219	5,323
Net operating loss from subsidiary acquisition	7,106	7,262
Deferred compensation	4,880	2,156
Unfunded benefit obligation	41,089	52,646
Utility energy commodity derivatives	21,549	42,271
Natural gas deferrals	13,983	7,085
Tax credits	11,604	8,484
Other	15,203	16,531
Total deferred income tax assets	133,505	154,376
Deferred income tax liabilities:		
Intangible assets from subsidiary acquisition	4,021	4,337
Differences between book and tax basis of utility plant	440,335	432,828
Power deferrals	9,720	20,721
Regulatory asset for pensions and other postretirement benefits	49,380	60,297
Power exchange contract	23,984	27,657
Utility energy commodity derivatives	21,549	42,271
Demand side management programs	7,808	7,693
Loss on reacquired debt	4,284	4,870
Interest rate swaps	4,342	5,251
Settlement with Coeur d'Alene Tribe	18,243	9,707
Other	10,032	9,123
Total deferred income tax liabilities	593,698	624,755
Net deferred income tax liability	$ 460,193	$ 470,379

Net current deferred income tax assets were $34.5 million as of December 31, 2009 and $18.6 million as of December 31, 2008. Net non-current deferred income tax liabilities were $494.7 million as of December 31, 2009 and $488.9 million as of December 31, 2008.

As of December 31, 2009, the Company had $11.6 million of state tax credit carryforwards. State tax credits expire from 2015 to 2021. 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 examined the Company's 2008 federal income tax return. This examination could result in a change in the liability for uncertain tax positions. However, an estimate of the range of any such possible change cannot be made at this time. The Company does not believe that any open tax years for state income taxes could result in any adjustments that would be significant to the consolidated financial statements.

In August 2005, the Treasury Department issued regulations and the IRS issued a revenue ruling that affects the tax treatment by Avista Corp. of certain indirect overhead expenses. Avista Corp. had previously made a tax election to currently deduct certain indirect overhead costs, starting with the 2002 tax return, that were capitalized for financial accounting purposes. This election allowed Avista Corp. to take tax deductions resulting in a total reduction of approximately $40 million in current tax liabilities for 2002, 2003 and 2004. These current tax benefits were deferred on the balance sheet and did not affect net income.

On the basis of the revenue ruling and related regulations, the IRS disallowed the tax deduction of indirect overhead expenses during their examination of the Company's 2001, 2002 and 2003 federal income tax returns. The Company believed that the tax deductions claimed on tax returns were appropriate based on the applicable statutes and regulations in effect at the time. Avista Corp. appealed the proposed IRS adjustment in April 2006. The Company repaid a portion of the previous tax deductions through tax payments in 2005, 2006 and 2008.

On September 10, 2008, the Company entered into a Settlement Agreement with the Appeals Division of the IRS that resolved all items noted during their audit of the Company's 2001 through 2003 tax years, including, among other things, indirect overhead expenses. The agreement was reviewed and approved by the Joint Committee on Taxation, and a settlement payment was received in December 2008. The original IRS disallowance and the Company's appeal of the indirect overhead issue caused a delay in associated tax refunds for net operating losses that were carried back to several earlier years.

The final settlement with the IRS freed up the refund years and set the amount owed for the 2001-2003 tax years. The net result was a refund to the Company of $14.7 million, plus interest of $5.7 million which has been included in other income — net in the Consolidated Statements of Income.

The following table presents the activity in the liability for unrecognized tax benefits during the years ended December 31 (dollars in thousands):

	2009	2008	2007
Balance as of the beginning of the year	$ —	$ 22,619	$ 22,619
Settlements with the IRS	—	(22,619)	—
Balance as of the end of the year	$ —	$ —	$ 22,619

The Company estimated that its liability for unrecognized tax benefits was $22.6 million as of December 31, 2007. In 2008, this amount was reclassified from a FIN 48 liability for unrecognized tax benefit, to a general tax liability on the Consolidated Balance Sheet. The amount did not impact the 2008 tax rate, as this deferred income tax adjustment was offset by an adjustment to current income taxes payable. The Company did not incur any penalties on income tax positions in 2009, 2008 or 2007. 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 of $97.9 million at December 31, 2009 and $115.0 million at December 31, 2008 related to the probable recovery of certain deferred income tax liabilities from customers through future rates.

NOTE 13. 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 $704.9 million in 2009, $951.4 million in 2008 and $733.5 million in 2007.

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):

	2010	2011	2012	2013	2014	Thereafter	Total
Power resources	$ 220,286	$ 133,287	$ 104,716	$ 79,543	$ 70,605	$ 485,980	$ 1,094,417
Natural gas resources	146,321	93,609	62,084	44,375	44,424	431,904	822,717
Total	$ 366,607	$ 226,896	$ 166,800	$ 123,918	$ 115,029	$ 917,884	$ 1,917,134

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 generally 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):

	2010	2011	2012	2013	2014	Thereafter	Total
Contractual obligations	$ 46,773	$ 55,084	$ 48,457	$ 52,181	$ 53,211	$ 573,643	$ 829,349

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 $12.6 million in 2009, $14.9 million in 2008 and $18.0 million in 2007.

Information as of December 31, 2009 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	$ 1,658	$ 883	$ 909	2011
Douglas County PUD:						
Wells Project	3.5%	30,000	1,609	698	3,728	2018
Grant County PUD:						
Priest Rapids Project	3.3%	31,500	4,377	726	7,854	2055
Wanapum Project (2)	7.4%	76,800	4,989	2,394	13,554	2055
Totals		175,300	$ 12,633	$ 4,701	$ 26,045	

(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 the year 2009. Debt service costs are included in annual costs.*

(2) *A previous contract expired on October 31, 2009. A new contract was completed in 2001 with an expiration date of 2055. Beginning in November 2009, the Company's rights to the output were reduced from 8.2 percent to 3.3 percent. Under the new contract the Company has the rights to the output but not the obligation to take the output. In September of each year the Company is required to determine if it will take the output for the subsequent year.*

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):

	2010	2011	2012	2013	2014	Thereafter	Total
Minimum payments	$ 2,985	$ 2,926	$ 2,500	$ 2,496	$ 2,368	$ 30,777	$ 44,052

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

NOTE 14. SHORT-TERM BORROWINGS

Avista Corp. has a committed line of credit agreement with various banks in the total amount of $320.0 million with an expiration date of April 5, 2011. Under the credit agreement, the Company can borrow or request the issuance of letters of credit in any combination up to $320.0 million. Total letters of credit outstanding were $28.4 million as of December 31, 2009 and $24.3 million as of December 31, 2008. The committed line of credit is secured by $320.0 million of 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.

Additionally, the Company has a committed line of credit agreement with various banks in the total amount of $75.0 million with an expiration date of April 5, 2011. Avista Corp. may elect to increase the committed line of credit by up to $25.0 million under the same agreement. The committed line of credit is secured by $75.0 million of 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 agreements contain customary covenants and default provisions, including a covenant requiring the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Utilities for the preceding twelve-month period at the end of any fiscal quarter to be greater than 1.6 to 1. As of December 31, 2009, the Company was in compliance with this covenant with a ratio of 4.23 to 1. The committed line of credit agreements also have a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 70 percent at any time. As of December 31, 2009, the Company was in compliance with this covenant with a ratio of 53.6 percent.

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 and for the years ended December 31 (dollars in thousands):

	2009	2008	2007
Balance outstanding at end of period	$ 87,000	$ 250,000	$ —
Maximum balance outstanding during the period	$ 275,000	$ 250,000	$ 48,000
Average balance outstanding during the period	$ 186,474	$ 48,426	$ 6,833
Average interest rate during the period	0.65%	3.04%	7.91%
Average interest rate at end of period	0.59%	0.81%	—%

ADVANTAGE IQ

Advantage IQ has a committed credit agreement with an expiration date of February 2011. On July 1, 2009, the committed amount was increased from $12.5 million to $15.0 million under the terms of the credit agreement. Advantage IQ may elect to increase the credit facility to $25.0 million under the same agreement. The credit agreement is secured by substantially all of Advantage IQ's assets.

Balances outstanding and interest rates of borrowings under Advantage IQ's credit agreement were as follows as of and for the years ended December 31 (dollars in thousands):

	2009	2008	2007
Balance outstanding at end of period	$ 5,700	$ 2,200	$ —
Maximum balance outstanding during the period	$ 9,700	$ 3,000	$ —
Average balance outstanding during the period	$ 4,090	$ 1,658	$ —
Average interest rate during the period	1.42%	3.48%	—
Average interest rate at end of period	1.23%	2.08%	—

NOTE 15. LONG-TERM DEBT

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

Maturity Year	Description	Interest Rate	2009	2008
2010	Secured Medium-Term Notes	6.67% — 8.02%	$ 35,000	$ 35,000
2012	Secured Medium-Term Notes	7.37%	7,000	7,000
2013	First Mortgage Bonds	6.13%	45,000	45,000
2013	First Mortgage Bonds	7.25%	30,000	30,000
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
2022	First Mortgage Bonds (1)	5.13%	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 (2)	(2)	66,700	66,700
2034	Secured Pollution Control Bonds (3)	(3)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
	Total secured long-term debt		1,151,700	901,700
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Other long-term debt and capital leases		3,018	3,006
	Interest rate swaps		(1,844)	(14,129)
	Unamortized debt discount		(1,936)	(1,512)
	Total		1,155,038	893,165
	Secured Pollution Control Bonds held by Avista Corporation (2) (3)		(83,700)	(66,700)
	Current portion of long-term debt		(35,189)	(17,207)
	Total long-term debt		$ 1,036,149	$ 809,258

(1) *In September 2009, the Company issued $250.0 million of 5.125 percent First Mortgage Bonds due in 2022.*

(2) *On December 31, 2008, $66.7 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds, Series 1999A (Avista Corporation Colstrip Project) due 2032 were remarketed. Avista Corp. purchased these Pollution Control Bonds and expects that at a later date, subject to market conditions, these bonds will be remarketed to unaffiliated investors or refunded by a new issue. Although Avista Corp. is now the holder of these Pollution Control Bonds, the bonds will not be cancelled but will remain outstanding under the City of Forsyth's indenture. However, so long as Avista Corp. is the holder, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Consolidated Balance Sheet.*

(3) *In December 2008, the City of Forsyth, Montana issued $17.0 million of its Pollution Control Revenue Refunding Bonds, Series 2008 (Avista Corp. Colstrip Project) due 2034 on behalf of Avista Corp. The proceeds of the Bonds were used to refund $17.0 million of Pollution Control Revenue Refunding Bonds, Series 1999B (Avista Corp. Colstrip Project) issued by the City of Forsyth, Montana on behalf of Avista Corp., which were subject to remarketing or refunding on December 31, 2008. In December 2009, Avista Corp. purchased the Bonds and expects that at a later date, subject to market conditions, the bonds will be refunded or remarketed to unaffiliated investors. Although Avista Corp. is now the holder of these Pollution Control Bonds, the bonds will not be cancelled but will remain outstanding under the City of Forsyth's indenture. However, so long as Avista Corp. is the holder, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Consolidated Balance Sheet.*

The following table details future long-term debt maturities including long-term debt to affiliated trusts (see Note 16) (dollars in thousands):

	2010	2011	2012	2013	2014	Thereafter	Total
Debt maturities	$ 35,000	$ —	$ 7,000	$ 75,000	$ —	$ 1,006,647	$ 1,123,647

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) 70 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; provided, however, that 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, 2009, property additions and retired bonds would have entitled the Company to issue $668.5 million in aggregate principal amount of additional First Mortgage Bonds. However, using an interest rate of 8 percent on additional First Mortgage Bonds, and based on net earnings for the 12 months ended December 31, 2009, the net earnings test would limit the principal amount of additional bonds the Company could issue to $607.5 million.

See Note 14 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its $320.0 million and $75.0 million committed line of credit agreements.

NOTE 16. LONG-TERM DEBT TO AFFILIATED TRUSTS

In 2004, the Company issued Junior Subordinated Debt Securities, with a principal amount of $61.9 million to AVA Capital Trust III, an affiliated business trust formed by the Company. Concurrently, AVA Capital Trust III issued $60.0 million of Preferred Trust Securities to third parties and $1.9 million of Common Trust Securities to the Company. On April 1, 2009, AVA Capital Trust III redeemed all of the Preferred Trust Securities issued to third parties with a principal balance of $60.0 million and all of the Common Trust Securities issued to the Company with a principal balance of $1.9 million. Concurrently, the Company redeemed the total amount outstanding of its Junior Subordinated Debt Securities, at 100 percent of the principal amount ($61.9 million) plus accrued interest held by AVA Capital Trust III. The Company's net redemption of $60.0 million was funded by borrowings under its $320.0 million committed line of credit agreement.

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 annual distribution rate paid during 2009 ranged from 1.22 percent to 3.06 percent. As of December 31, 2009, the annual distribution rate was 1.22 percent. 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 has 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 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 17. 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 $5.6 million in 2009, $4.8 million in 2008 and $4.8 million in 2007.

Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2009 were as follows (dollars in thousands):

	2010	2011	2012	2013	2014	Thereafter	Total
Minimum payments required	$ 4,420	$ 3,966	$ 3,759	$ 3,503	$ 3,529	$ 6,750	$ 25,927

NOTE 18. GUARANTEES

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities issued by its affiliate, Avista Capital II, to the extent that this entity has funds available for such payments from its debt securities.

The output from the Lancaster Plant is contracted to Avista Turbine Power, Inc. (ATP), an affiliate of Avista Energy, through 2026 under a power purchase agreement. Avista Corp. has provided Rathdrum Power LLC, the owner of the Lancaster Plant, a guarantee under which Avista Corp. has guaranteed ATP's performance under the power purchase agreement. The majority of the rights and obligations of this agreement were conveyed to Shell Energy through the end of 2009. Beginning in January 2010, the rights and obligations under the power purchase agreement were conveyed to Avista Utilities.

In connection with the transaction, on June 30, 2007, Avista Energy and its affiliates entered into an Indemnification Agreement with Shell Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Shell Energy each agree to provide indemnification of the other and the other's affiliates for certain events and matters described in the purchase and sale agreement entered into on April 16, 2007 and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the western energy markets in 2000 and 2001 (see Note 24), existing litigation, tax liabilities, and matters related to storage rights at Jackson Prairie. In general, such indemnification is not required unless and until a party's claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy's obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of $30 million plus certain fees and expenses. The Guaranty will terminate

April 30, 2011 except for claims made prior to termination. The Company has not recorded any liability related to this guaranty.

NOTE 19. PREFERRED STOCK-CUMULATIVE (SUBJECT TO MANDATORY REDEMPTION)

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2009 and 2008. In September 2007, the Company redeemed the 262,500 remaining outstanding shares of preferred stock for $26.25 million.

NOTE 20. FAIR VALUE

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. The carrying values of cash and cash equivalents, restricted cash, 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) 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, 2009 and 2008 (dollars in thousands):

	2009		2008	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt	$ 1,072,100	$ 1,079,857	$ 839,100	$ 875,451
Long-term debt to affiliated trusts	51,547	43,534	113,403	102,027

These estimates of fair value were primarily based on available market information.

Energy commodity derivative assets and liabilities, 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. U.S. GAAP defines a fair value hierarchy that 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. Level 3 instruments include those that may be more structured or otherwise tailored to the Company's needs.

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, 2009 and 2008 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counter-party Netting (1)	Total
December 31, 2009					
Assets:					
Energy commodity derivatives	$ —	$ 11,898	$ 57,276	$ (15,934)	$ 53,240
Deferred compensation assets:					
Fixed income securities (2)	2,011	—	—	—	2,011
Equity securities (2)	5,863	—	—	—	5,863
Total	$ 7,874	$ 11,898	$ 57,276	$ (15,934)	$ 61,114
Liabilities:					
Energy commodity derivatives	$ —	$ 27,086	$ 7,806	$ (15,934)	$ 18,958
Foreign currency derivatives	—	50	—	—	50
Total	$ —	$ 27,136	$ 7,806	$ (15,934)	$ 19,008
December 31, 2008					
Assets:					
Energy commodity derivatives	$ —	$ 40,104	$ 68,047	$ (47,604)	$ 60,547
Deferred compensation assets:					
Fixed income securities (2)	1,889	—	—	—	1,889
Equity securities (2)	5,101	—	—	—	5,101
Interest rate swaps	—	875	—	—	875
Total	$ 6,990	$ 40,979	$ 68,047	$ (47,604)	$ 68,412
Liabilities:					
Energy commodity derivatives	$ —	$ 110,123	$ 16,085	$ (47,604)	$ 78,604

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

(2) *These assets are trading securities.*

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. 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 7 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 $1.6 million as of December 31, 2009 and $1.8 million as of December 31, 2008.

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	
	2009	2008	2009	2008
Balance as of January 1	$ 68,047	$ 98,943	$ (16,085)	$ (36,506)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	(7,202)	(22,586)	7,747	18,715
Purchases, issuances, and settlements, net	(3,569)	(8,310)	532	1,706
Transfers to other categories	—	—	—	—
Ending balance as of December 31	$ 57,276	$ 68,047	$ (7,806)	$ (16,085)

(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.*

NOTE 21. 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 2009, 2008 and 2007 are disclosed in the Consolidated Statements of Equity.

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 December 2009, the Company entered into an amended and restated sales agency agreement with a sales agent to issue up to 1.25 million shares of its common stock from time to time. The Company originally entered into a sales agency agreement to issue up to 2 million shares of its common stock in December 2006. In 2008, the Company issued 750,000 shares of its common stock under this sales agency agreement. The Company did not issue any shares under this sales agency agreement in 2009 and 2007.

NOTE 22. 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):

	2009	2008	2007
Numerator:			
Net income attributable to Avista Corporation	$ 87,071	$ 73,620	$ 38,475
Subsidiary earnings adjustment for dilutive securities	(114)	(249)	(349)
Adjusted net income attributable to Avista Corporation for computation of diluted earnings per common share	$ 86,957	$ 73,371	$ 38,126
Denominator:			
Weighted-average number of common shares outstanding-basic	54,694	53,637	52,796
Effect of dilutive securities:			
Contingent stock awards	163	213	168
Stock options	85	178	299
Weighted-average number of common shares outstanding-diluted	54,942	54,028	53,263
Earnings per common share attributable to Avista Corporation:			
Basic	$ 1.59	$ 1.37	$ 0.73
Diluted	$ 1.58	$ 1.36	$ 0.72

Total stock options outstanding excluded in the calculation of diluted earnings per common share attributable to Avista Corporation were 218,450 for 2009, 250,950 for 2008 and 303,950 for 2007. These 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 23. 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 3.5 million shares of its common stock for grant under the 1998 Plan. As of December 31, 2009, 0.7 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, 2009, 1.7 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 of $2.9 million for 2009, $3.0 million for 2008 and $2.7 million for 2007, which is included in other operating expenses in the Consolidated Statements of Income. The total income tax benefit recognized in the Consolidated Statements of Income was $1.0 million for 2009, $1.1 million for 2008 and $1.0 million for 2007.

STOCK OPTIONS

The following summarizes stock options activity under the 1998 Plan and the 2000 Plan for the years ended December 31:

	2009	2008	2007
Number of shares under stock options:			
Options outstanding at beginning of year	748,673	1,411,911	1,541,045
Options granted	—	—	—
Options exercised	(200,225)	(582,238)	(123,134)
Options canceled	(24,475)	(81,000)	(6,000)
Options outstanding and exercisable at end of year	523,973	748,673	1,411,911
Weighted average exercise price:			
Options exercised	$ 13.83	$ 13.91	$ 15.14
Options canceled	$ 22.69	$ 21.70	$ 26.59
Options outstanding and exercisable at end of year	$ 16.30	$ 15.85	$ 15.38
Intrinsic value of options exercised (in thousands)	$ 1,180	$ 4,248	$ 1,022
Intrinsic value of options outstanding (in thousands)	$ 2,774	$ 2,643	$ 8,697

Information for options outstanding and exercisable as of December 31, 2009 is as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$10.17 — $12.41	285,323	$ 11.11	2.4
$15.88 — $19.34	11,200	16.56	2.0
$20.11 — $23.00	213,050	22.46	0.9
$26.59 — $28.47	14,400	27.69	0.2
Total	523,973	$ 16.30	1.7

Total cash received from the exercise of stock options was $2.8 million for 2009, $8.1 million for 2008 and $1.9 million for 2007. As of December 31, 2009 and 2008, 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, 2009 was one year.

The following table summarizes restricted stock activity for the years ended December 31:

	2009	2008	2007
Unvested shares at beginning of year	55,939	28,137	36,180
Shares granted	44,400	43,400	31,860
Shares cancelled	(10,000)	(1,230)	(19,936)
Shares vested	(18,435)	(14,368)	(19,967)
Unvested shares at end of year	71,904	55,939	28,137
Weighted average fair value at grant date	$ 18.18	$ 20.05	$ 25.60
Unrecognized compensation expense at end of year (in thousands)	$ 668	$ 691	$ 517
Intrinsic value, unvested shares at end of year (in thousands)	$ 1,552	$ 1,084	$ 606
Intrinsic value, shares vested during the year (in thousands)	$ 345	$ 293	$ 461

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 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. 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:

	2009	2008	2007
Risk-free interest rate	1.3%	2.2%	4.8%
Expected life, in years	3	3	3
Expected volatility	25.8%	20.2%	19.4%
Dividend yield	3.6%	2.8%	2.5%
Weighted average grant date fair value (per share)	$ 17.22	$ 16.96	$ 18.71

The fair value includes both performance shares and dividend equivalent rights.

The following summarizes performance share activity:

	2009	2008	2007
Opening balance of unvested performance shares	252,923	207,841	300,406
Performance shares granted	163,900	170,100	114,640
Performance shares canceled	(43,758)	(5,239)	(45,632)
Performance shares vested	(72,464)	(119,779)	(161,573)
Ending balance of unvested performance shares	300,601	252,923	207,841
Intrinsic value of unvested performance shares (in thousands)	$ 6,490	$ 4,902	$ 4,477
Unrecognized compensation expense (in thousands)	$ 2,453	$ 2,227	$ 2,058

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2009 was 1.5 years. Unrecognized compensation expense as of December 31, 2009 will be recognized during 2010 and 2011.

The following summarizes the impact of the market condition on the vested performance shares:

	2009	2008	2007
Performance shares vested	72,464	119,779	161,573
Impact of market condition on shares vested	(72,464)	21,560	(56,551)
Shares of common stock earned	—	141,339	105,022
Intrinsic value of common stock earned (in thousands)	$ —	$ 2,739	$ 2,262

In 2009, 2008 and 2007, the number of performance shares vested was adjusted by (100) percent, 18 percent and (35) percent based on the performance condition achieved. 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, 2009 and 2008, the Company had recognized compensation expense and a liability of $0.3 million and $0.5 million related to the dividend component of performance share grants.

ADVANTAGE IQ

Advantage IQ has an employee stock incentive plan under which certain employees of Advantage IQ may be granted options to purchase shares 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 Advantage IQ was $2.2 million as of December 31, 2009, which will be expensed during 2010 through 2013.

In 2007, Advantage IQ amended its employee stock incentive plan to provide an annual window at which time holders of common stock can put their shares back to Advantage IQ providing the shares are held for a minimum of six months. In 2009, Advantage IQ 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. As the repurchase feature is at the discretion of the minority shareholders and option holders, there was redeemable noncontrolling interests of $6.9 million as of December 31, 2009 for the intrinsic value of stock options outstanding, as well as outstanding redeemable stock. Additionally, there was redeemable noncontrolling interests of $27.9 million related to the Cadence Network acquisition, as the previous owners can exercise a right to put their stock back to Advantage IQ (refer to Note 5 for further information). During 2009, $4.7 million of common stock was repurchased from Advantage IQ employees. During 2008, $6.6 million of common stock was repurchased from Advantage IQ employees.

NOTE 24. 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 these proceedings, 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, California Parties 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 and the FERC's denial of rehearing requests, the Company does not expect that this proceeding will have any material adverse effect on its financial condition, results of operations or cash flows. Furthermore, based on information currently known to the Company regarding the Bidding Investigation and the fact that the FERC Staff did not find any evidence of manipulative behavior, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows. The Company has not accrued a liability related to this matter.

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. That filing was accepted in orders issued by the FERC in January 2006 and November 2006. In June 2009, the FERC reversed, in part, its previous decision and ordered a compliance filing requiring an adjustment to the return on investment component of Avista Energy's cost filing. That compliance filing was made in July 2009.

The CalISO continues to work on its compliance filing for the Refund Period, which will show "who owes what to whom." In May 2009, the CalISO filed its 43rd status report on the California recalculation process confirming that the preparatory and the FERC refund recalculations are complete (as are calculations related to fuel cost allowance offsets, emission offsets, cost-recovery offsets, and the majority of the interest calculations). Once the FERC rules on several open issues, the CalISO states that it intends to: (1) perform the necessary adjustment to remove refunds associated with non-jurisdictional entities and allocate that shortfall to net refund recipients; and (2) work with the parties to the various global settlements to make appropriate adjustments to the CalISO's data in order to properly reflect those adjustments. After completing these calculations, the CalISO states that it intends to make a compliance filing with the FERC that presents the final financial position of each party that participated in its markets during the Refund Period.

The 2001 bankruptcy of PG&E resulted in a default on its payment obligations to the CalPX. As a result, Avista Energy has not been paid for all of its energy sales during the Refund Period. Those funds are now in escrow accounts and will not be released until the FERC issues an order directing such release in the California refund proceeding. As of December 31, 2009, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from 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 Federal Power Act (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. Petitions for rehearing were denied in April 2009. In July 2009, Avista Energy and Avista Utilities filed a motion at the FERC, asking that the companies be dismissed from any further proceedings arising under section 309 pursuant to the remand. The filing pointed out that section 309 relief is based on tariff violations of the seller, and as to Avista Energy and Avista Utilities, these allegations had already been fully adjudicated in the proceeding that gave rise to the Agreement in Resolution, discussed above. There, the FERC absolved both companies of all allegations of market manipulation or wrongdoing that would justify or permit FPA sections 206 or 309 remedies during 2000 and 2001. In November 2009, the FERC issued an order establishing an evidentiary hearing before an administrative law judge to address the issues remanded by the Ninth Circuit without addressing the Company's pending motion. In December 2009, the Company again brought the issue to the FERC's attention but its motion remains pending.

Because the resolution of the California refund proceeding remains uncertain, legal counsel cannot express an opinion on the extent of the Company's liability, if any. However, based on information currently known, the Company does not expect that the refunds ultimately ordered for the Refund Period will have a material adverse effect on its financial condition, results of operations or cash flows. This is primarily due to the fact that the FERC orders have stated that any refunds will be netted against unpaid amounts owed to the respective parties and the Company does not believe that refunds would exceed unpaid amounts owed to the Company. As such, the Company has not accrued a liability related to this matter.

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. Requests for rehearing were denied in April 2009.

In May 2009, the California AG filed a complaint against both Avista Energy and Avista Utilities seeking refunds on sales made to CERS during the period January 18, 2001 to June 20, 2001 under section 309 of the FPA (the Brown Complaint). The sales at issue are limited in scope and are duplicative of claims already at issue in the Pacific Northwest proceeding, discussed above. In August 2009, the City of Tacoma and the Port of Seattle filed a motion asking the FERC to summarily re-price sales of energy in the Pacific Northwest during 2000 and 2001. In October 2009, Avista Corp. filed, as part of the Transaction Finality Group, an answer to that motion and in addition, made its own recommendations for further proceedings in this docket. Those pleadings are pending before the FERC.

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, if refunds were ordered by the FERC, could be liable to make payments, but also could be entitled to receive refunds from other FERC-jurisdictional entities. The opportunity to make claims against non-jurisdictional entities may be limited based on existing law. 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 or could be entitled to receive. 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. The Company has not accrued a liability related to this matter.

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 but directing sellers to re-file certain transaction summaries. It was not clear that Avista Corp. and its subsidiaries were subject to this directive but the Company took the conservative approach and re-filed certain transaction summaries in June and July of 2002. 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, but did not order any refunds, leaving it to the FERC to consider appropriate remedial options.

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 will be allowed 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 particular, the parties are directed to address whether the seller at any point reached a 20 percent generation market share threshold, and if the seller did reach a 20 percent market share, whether other factors were present to indicate that the seller did not have the ability to exercise market power. The California AG, CPUC, PG&E, and SCE filed their testimony in July 2009. Avista Energy's answering testimony was filed in September 2009. On the same day, the FERC staff filed its answering testimony taking the position that, using the test the FERC directed to be applied in this proceeding, Avista Energy does not have market power. Cross answering testimony and rebuttal testimony were filed in November 2009. A hearing is expected to commence in April 2010.

Based on information currently known to the Company's management and the fact that neither Avista Utilities nor Avista Energy ever reached a 20 percent generation market share during 2000 or 2001, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows. The Company has not accrued any liability related to this matter.

COLSTRIP GENERATING PROJECT COMPLAINTS

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. The trial is set to begin in May 2011. Because the resolution of this complaint remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect this complaint will have a material adverse effect on its financial condition, results of operations or cash flows. The Company has not accrued a liability related to this matter.

HARBOR OIL INC. SITE

Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, the Environmental Protection Agency (EPA) Region 10 provided notification to Avista Corp. and several other parties, as customers of Harbor Oil, that the EPA had determined that hazardous substances were released at the Harbor Oil site in Portland, Oregon and that Avista Corp. and several other parties may be liable for investigation and cleanup of the site under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as the federal "Superfund" law, which provides for joint and several liability. The initial indication from the EPA is that the site may be contaminated with PCBs, petroleum hydrocarbons, chlorinated solvents and heavy metals. Six potentially responsible parties, including Avista Corp., signed an Administrative Order on Consent with the EPA on May 31, 2007 to conduct a remedial investigation and feasibility study (RI/FS). The total cost of the RI/FS is estimated to be $1.5 million and it is expected that it will be completed by early 2011. The actual cleanup, if any, will not occur until the RI/FS is complete. Based on the review of its records related to Harbor Oil, the Company does not believe it is a major contributor to this potential environmental contamination based on the small volume of waste oil it delivered to the Harbor Oil site. However, there is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred. Other than its share of the RI/FS, the Company has not accrued a liability related to this matter.

LAKE COEUR D'ALENE

In July 1998, the United States District Court for the District of Idaho issued its finding that the Coeur d'Alene Tribe (the Tribe) owns, among other things, portions of the bed and banks of Lake Coeur d'Alene (Lake) lying within the current boundaries of the Tribe's reservation lands. The United States District Court decision was affirmed by the United States Court of Appeals for the Ninth Circuit and the United States Supreme Court in June 2001. This ownership decision resulted in, among other things, Avista Corp. being liable to the Tribe for water storage on the Tribe's land and for the use of the Tribe's reservation lands under Section 10(e) of the Federal Power Act (Section 10(e) payments). The Company's Post Falls Hydroelectric Generating Station (Post Falls) controls the water level in the Lake for portions of the year (including portions of the lakebed owned by the Tribe).

In December 2008, Avista Corp., the Tribe and the United States Department of Interior (DOI) finalized an agreement regarding a range of issues related to Post Falls and the Lake. The agreement establishes the amount of past and future compensation Avista Corp. will pay for Section 10(e) payments and issues related to licensing of the Company's hydroelectric generating facilities located on the Spokane River (see Spokane River Licensing below).

Avista Corp. agreed to compensate the Tribe a total of $39 million ($25 million paid in 2008, $10 million paid in 2009 and $4 million to be paid in 2010) for trespass and Section 10(e) payments for past storage of water for the period from 1907 through 2007. Avista Corp. agreed to compensate the Tribe for future storage of water through Section 10(e) payments of $0.4 million per year beginning in 2008 and continuing through the first 20 years of the new license and $0.7 million per year through the remaining term of the license.

In addition to Section 10(e) payments, Avista Corp. agreed to make annual payments over the life of the new FERC license to fund a variety of protection, mitigation and enhancement measures on the Coeur d'Alene Reservation required under Section 4(e) of the Federal Power Act. These payments involve creation of a Coeur d'Alene Reservation Trust Restoration Fund (the Trust Fund). Annual payments from the Company to the Trust Fund for protection, mitigation and enhancement measurements commenced with the issuance of the new FERC license in June 2009 and total $100 million over the 50-year license term.

The WUTC and IPUC approved deferral and future recovery of amounts paid to the Tribe and the Trust Fund through general rate cases in 2009.

On January 27, 2009, the Public Counsel Section of the Washington Attorney General's Office (Public Counsel) filed a Petition for Judicial Review (in Thurston County Superior Court) of the WUTC's December 2008 order approving the Company's general rate case settlement. Public Counsel raised a number of issues that were previously argued before the WUTC. These include whether the recovery of settlement costs associated with resolving the dispute with the Tribe would constitute illegal "retroactive ratemaking" (the Washington portion of these costs was $25.2 million). Public Counsel also questioned whether the WUTC's decision to entertain supplemental testimony to update the Company's filing for power supply costs during the course of the proceedings was appropriate. Finally, Public Counsel argued that the settlement improperly included advertising costs, dues and donations, and certain other expenses. The appeal itself did not prevent the new rates from going into effect.

On December 18, 2009, the Thurston County Superior Court affirmed the decision of the WUTC and rejected the arguments of Public Counsel, with the exception of disallowing $0.1 million of miscellaneous expenses, including charitable donations. Public Counsel has until March 4, 2010 to further appeal the WUTC's decision.

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, which have a total present capability of 144.1 MW) are under one FERC license 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 FERC issued a new single 50-year license for the Spokane River Project on June 18, 2009.

The license incorporated the 4(e) conditions that were included in the December 2008 Settlement Agreement with the DOI and the 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. Various issues that were appealed under the Washington 401 Water Quality Certification were subsequently resolved through settlement.

As part of the Settlement Agreement with the Washington Department of Ecology (DOE), the Company is currently engaged with the DOE and the EPA Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On February 12, 2010, the DOE submitted the TMDL for the EPA's review and approval. Once the TMDL process is completed, and the Company's level of responsibility related to low dissolved oxygen in Lake Spokane is established, the Company will identify potential mitigation measures. It is not possible to provide cost estimates at this time because the mitigation measures have not been fully indentified or approved by the DOE. It is also possible the TMDL will be appealed by one or more parties if it is approved by the EPA.

The Company has begun implementing the environmental and operational conditions required in the license for the Spokane River Project. The estimated cost to implement the license conditions for the five hydroelectric plants is $334 million over the 50 year license term. This will increase the Spokane River Project's cost of power by about 40 percent, while decreasing annual generation by approximately one-half of one percent. Costs to implement mitigation measures related to the TMDL are not included in these cost estimates.

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 the licensing of the Spokane River Project.

CLARK FORK SETTLEMENT AGREEMENT

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") with the Idaho Department of Environmental Quality (Idaho DEQ) and U.S. Fish and Wildlife Service (USFWS). This submission was part of the Clark Fork Settlement Agreement for licensing the use of Cabinet Gorge. The GSCP provides for the opening and modification of possibly two diversion tunnels around Cabinet Gorge to allow streamflow to be diverted when flows are in excess of powerhouse capacity. In 2007, engineering studies determined that the tunnels would not sufficiently reduce Total Dissolved Gas (TDG). In consultation with the Idaho DEQ and the USFWS, the Company developed addendum to the GSCP. The GSCP addendum abandons the existing concept to reopen the two diversion tunnels and requires the Company to evaluate a variety of smaller capacity options to abate TDG over the next several years. The addendum was filed with the FERC in October 2009 and is pending approval.

In 1999, the USFWS listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company is evaluating the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies will help the Company and other parties determine the best use of funds toward continuing fish passage efforts or other bull trout population enhancement measures. In the fall of 2009 the Company initiated a contractor selection process for the design of a permanent upstream passage facility at Cabinet Gorge. On January 13, 2010, the USFWS proposed to revise its 2005 designation of critical habitat for the bull trout. The proposed revisions include the lower Clark Fork River as critical habitat. The USFWS is accepting public comment on the proposed revisions until March 15, 2010. The Company is reviewing the proposed revisions.

AIR QUALITY

The Company must be in compliance with requirements under the Clean Air Act and Clean Air Act Amendments for its thermal generating plants. The Company continues to monitor legislative developments at both the state and national level for the potential of further restrictions on sulfur dioxide, nitrogen oxide and carbon dioxide, as well as other greenhouse gas and mercury emissions.

In 2006, the Montana Department of Environmental Quality (Montana DEQ) adopted final rules for the control of mercury emissions from coal-fired plants. The new rules set strict mercury emission limits by 2010, and put in place a recurring ten-year review process to ensure facilities are keeping pace with advancing technology in mercury emission control. The rules also provide for temporary alternate emission limits provided certain provisions are met, and they allocate mercury emission credits in a manner that rewards the cleanest facilities.

Compliance with new and proposed requirements and possible additional legislation or regulations results in increases to capital expenditures and operating expenses for expanded emission controls at the Company's thermal generating facilities. The Company, along with the other owners of Colstrip, completed the first phase of testing on two mercury control technologies. The joint owners of Colstrip believe, based upon current results, that the plant will be able to comply with the Montana law without utilizing the temporary alternate emission limit provision. Current estimates indicate that the Company's share of installation capital costs will be $1.4 million and annual operating costs will increase by $1.5 million (began in late-2009). The Company will continue to seek recovery, through the ratemaking process, of the costs to comply with various air quality requirements.

ALUMINUM RECYCLING SITE

In October 2009, the Company (through its subsidiary Pentzer Corporation) received notice from the DOE proposing to find Pentzer liable for a release of hazardous substances under the Model Toxics Control Act (MTCA), under Washington state law. The subject property adjoins land owned by the Union Pacific Railroad (UPR). UPR leased their property to operators of a facility designated by DOE as "Aluminum Recycling — Trentwood." Operators of that property maintained piles of aluminum "black dross," which can be designated as a state-only dangerous waste in Washington State. Operators placed a portion of the aluminum dross pile on the site owned by Pentzer Corporation. The Company 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, the Company received notice from the DOE that it had been designated as a potentially liable party for any hazardous substances located on this site. There is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred. The Company has not accrued a liability related to this matter.

COLLECTIVE BARGAINING AGREEMENTS

As of December 31, 2009, the Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represented 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 on March 26, 2010. Two local agreements in Oregon, which cover approximately 50 employees, expire in April 2010. Negotiations are currently ongoing for these labor agreements.

OTHER CONTINGENCIES

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

The Company routinely assesses, based on in-depth 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 have and have not agreed to a settlement and 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.

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, been listed as "threatened" or been petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company.

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 potentially adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho is conducting an adjudication in northern Idaho, which will ultimately include both 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 participating in these extensive adjudication processes, which are unlikely to be concluded in the foreseeable future.

NOTE 25. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2012. Total payments under these contracts were $15.5 million in 2009, $15.4 million in 2008 and $15.4 million in 2007. 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 $13.2 million in 2010, $12.9 million in 2011, and $12.2 million in 2012. 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.

REGULATORY ASSETS AND LIABILITIES

The following table presents the Company's regulatory assets and liabilities (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 2009	Total 2008
Regulatory assets:						
Investment in exchange power-net	2019	$ 23,683	$ —	$ —	$ 23,683	$ 26,133
Regulatory assets for deferred income tax	(3)	—	97,945	—	97,945	115,005
Regulatory assets for pensions and other postretirement benefit plans	(4)	—	—	141,085	141,085	172,278
Current regulatory asset for utility derivatives	(5)	—	8,332	—	8,332	60,229
Power deferrals	(3)	27,771	—	—	27,771	57,607
Unamortized debt repurchase costs	(6)	15,196	—	—	15,196	17,152
Regulatory asset for settlement with Coeur d'Alene Tribe	2059	49,134	—	6,000	55,134	41,733
Demand side management programs	(3)	—	11,894	—	11,894	11,137
Montana lease payments	(3)	7,171	—	—	7,171	8,208
Other regulatory assets	(3)	5,113	6,349	8,968	20,430	24,033
Total regulatory assets		$ 128,068	$ 124,520	$ 156,053	$ 408,641	$ 533,515
Regulatory Liabilities:						
Residential exchange	2010	$ 2,900	$ —	$ —	$ 2,900	$ —
Oregon Senate Bill 408	2010 — 2011	1,790	—	—	1,790	2,452
Natural gas deferrals	(3)	39,952	—	—	39,952	18,646
Regulatory liability for utility plant retirement costs	(7)	217,176	—	—	217,176	213,747
Non-current regulatory liability for utility derivatives	(5)	—	42,611	—	42,611	42,172
Income tax related liabilities	(3)	—	13,045	—	13,045	8,484
Other regulatory liabilities	(3)	4,792	1,648	—	6,440	8,483
Total regulatory liabilities		$ 266,610	$ 57,304	$ —	$ 323,914	$ 293,984

(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 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 primary 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.

(7) This amount is dependent upon the cost of removal of underlying utility plant assets and the life of utility plant.

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 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 and the amount included in base retail rates for Washington customers. The Company must make a filing (no sooner than January 1, 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.

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 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. In June 2007, the IPUC approved continuation of the PCA mechanism with an annual rate adjustment provision. These annual October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period.

The following table shows activity in deferred power costs for Washington and Idaho during 2007, 2008 and 2009 (dollars in thousands):

	Washington	Idaho	Total
Deferred power costs as of December 31, 2006	$ 70,159	$ 9,357	$ 79,516
Activity from January 1 — December 31, 2007:			
Power costs deferred	16,344	16,750	33,094
Interest and other net additions	3,023	788	3,811
Recovery of deferred power costs through retail rates	(31,002)	(5,732)	(36,734)
Deferred power costs as of December 31, 2007	58,524	21,163	79,687
Activity from January 1 — December 31, 2008:			
Power costs deferred	7,049	10,029	17,078
Interest and other net additions	2,231	1,153	3,384
Recovery of deferred power costs through retail rates	(30,852)	(11,690)	(42,542)
Deferred power costs as of December 31, 2008	36,952	20,655	57,607
Activity from January 1 — December 31, 2009:			
Power costs deferred	—	17,985	17,985
Interest and other net additions	879	388	1,267
Recovery of deferred power costs through retail rates	(31,567)	(17,521)	(49,088)
Deferred power costs as of December 31, 2009	$ 6,264	$ 21,507	$ 27,771

In February 2010, the WUTC approved the Company's request to eliminate the existing ERM surcharge. The surcharge was eliminated because the previous balance of deferred power costs has been substantially recovered. This will result in an overall rate reduction of 7 percent for the Company's Washington customers with no impact on income from operations or net income.

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 for the prior year, 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 $40.0 million as of December 31, 2009 and $18.6 million as of December 31, 2008.

GENERAL RATE CASES

The following is a summary of the Company's authorized rates of return in each jurisdiction:

Jurisdiction and service	Implementation Date	Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
Washington electric and natural gas	January 2010	8.25%	10.2%	46.5%
Idaho electric and natural gas	August 2009	8.55%	10.5%	50.0%
Oregon natural gas	November 2009	8.19%	10.1%	50.0%

WASHINGTON GENERAL RATE CASES

As approved by the WUTC, on January 1, 2008, electric rates for the Company's Washington customers increased by an average of 9.4 percent, which was designed to increase annual revenues by $30.2 million. As part of this general rate increase, the base level of power supply costs used in the ERM calculations was updated. Also, on January 1, 2008, natural gas rates increased by an average of 1.7 percent, which was designed to increase annual revenues by $3.3 million.

In September 2008, Avista Corp. entered into a settlement stipulation in its general rate case that was filed with the WUTC in March 2008. This settlement stipulation was approved by the WUTC in December 2008. The new electric and natural gas rates became effective on January 1, 2009. As agreed to in the settlement, base electric rates for the Company's Washington customers increased by an average of 9.1 percent, which was designed to increase annual revenues by $32.5 million. Base natural gas rates for the Company's Washington customers increased by an average of 2.4 percent, which was designed to increase annual revenues by $4.8 million.

On January 27, 2009, Public Counsel filed a Petition for Judicial Review (in Thurston County Superior Court) of the WUTC's December 2008 order approving Avista Corp.'s multiparty settlement. Public Counsel raised a number of issues that were previously argued before the WUTC. These included whether the recovery of settlement costs associated with resolving the dispute with the Coeur d'Alene Tribe would constitute illegal "retroactive ratemaking" (the Washington portion of these costs was $25.2 million). Public Counsel also questioned whether the WUTC's decision to entertain supplemental testimony by the Company to update its filing for power supply costs during the course of the proceedings was appropriate. Finally, Public Counsel argued that the settlement improperly included advertising costs, dues and donations, and certain other expenses. The appeal itself did not prevent the new rates from going into effect.

On December 18, 2009, the Thurston County Superior Court affirmed the decision of the WUTC and rejected the arguments of Public Counsel, with the exception of disallowing $0.1 million of miscellaneous expenses, including charitable donations. Public Counsel has until March 4, 2010 to further appeal the WUTC's decision.

On December 22, 2009, the WUTC issued an order on Avista Corp.'s electric and natural gas rate 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 is 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 is designed to increase annual revenues by $0.6 million. The new electric and natural gas rates became effective on January 1, 2010.

Following the execution of a partial settlement stipulation in September 2009, Avista Corp. revised downward its electric rate increase request from $69.8 million to $37.5 million, primarily due to the decline in the wholesale prices of electricity and natural gas. Avista Corp. also reduced its natural gas request from $4.9 million to $2.8 million. Under the partial settlement stipulation, the Company reached agreement with the other settling parties on issues in the areas of cost of capital, power supply, rate spread and rate design, and funding under the Low-Income Ratepayer Assistance Program. The WUTC approved this partial settlement stipulation in its order on December 22, 2009.

The WUTC did not allow Avista Corp. to include the costs associated with the power purchase agreement for the Lancaster Plant in rates, indicating the Company did not demonstrate compliance with certain requirements necessary for immediate inclusion in rates. However, the WUTC directed Avista Corp. to file to defer costs associated with the Lancaster Plant, with a carrying charge, for potential recovery in a future rate proceeding if the Company demonstrates that it has satisfied these requirements. The Company's proposed deferred accounting treatment for the net costs associated with the Lancaster Plant was approved by the WUTC in February 2010. The net costs associated with the power purchase agreement for the Lancaster Plant account for approximately half of the difference between the Company's revised electric rate increase request of $37.5 million and the $12.1 million increase approved by the WUTC.

The WUTC also did not allow for certain pro forma future capital additions to rate base, as well as certain increases in labor costs, tree trimming costs and information systems costs. These costs account for the majority of the remaining difference between the Company's revised electric rate increase request and the amount approved by the WUTC.

The partial settlement stipulation (as approved by the WUTC on December 22, 2009) is based on an overall rate of return of 8.25 percent with a common equity ratio of 46.5 percent and a 10.2 percent return on equity. The Company's original request was based on a proposed overall rate of return of 8.68 percent with a common equity ratio of 47.5 percent and an 11.0 percent return on equity.

IDAHO GENERAL RATE CASES

In August 2008, the Company entered into an all-party settlement stipulation in its general rate case that was filed with the IPUC in April 2008. This settlement stipulation was approved by the IPUC in September 2008. The new electric and natural gas rates became effective on October 1, 2008. As agreed to in the settlement, base electric rates for the Company's Idaho customers increased by an average of 12.0 percent, which was designed to increase annual revenues by $23.2 million. Base natural gas rates for the Company's Idaho customers increased by an average of 4.7 percent, which was designed to increase annual revenues by $3.9 million.

In June 2009, the Company entered into an all-party settlement stipulation in its electric and natural gas general rate cases that were filed with the IPUC in January 2009. This settlement stipulation was approved by the IPUC in July 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. Offsetting the base electric rate increase was an overall 4.2 percent decrease in the PCA surcharge, which was designed to decrease annual PCA revenues by $9.3 million, resulting in a net increase in annual revenues of $3.2 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. Offsetting the natural gas rate increase for residential customers was an equivalent PGA decrease of 2.1 percent. Large general services received a PGA decrease of 2.4 percent and interruptible services received a PGA decrease of 2.8 percent. The overall PGA decrease resulted in a $2.0 million decrease in annual PGA revenues, resulting in a net decrease in annual revenues of $0.1 million. The PGAs are designed to pass through changes in natural gas costs to customers with no change in gross margin or net income.

OREGON GENERAL RATE CASES

As approved by the OPUC in March 2008, natural gas rates for the Company's Oregon customers increased 0.4 percent effective April 1, 2008 (designed to increase annual revenues by $0.5 million) and increased an additional 1.1 percent effective November 1, 2008 (designed to increase annual revenues by an additional $1.4 million).

In September 2009, the Company entered into an all-party settlement stipulation in its 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 Oregon customers increased by an average of 7.1 percent, which is designed to increase annual revenues by $8.8 million.

NOTE 27. 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. Advantage IQ 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 the remaining activities of Avista 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	Advantage IQ	Other	Total Non-Utility	Intersegment Eliminations (1)	Total
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	—	23,408	23,408	—	822,947
Other operating expenses	229,907	60,985	21,710	82,695	—	312,602
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
For the year ended December 31, 2008:						
Operating revenues	$ 1,572,664	$ 59,085	$ 45,014	$ 104,099	$ —	$ 1,676,763
Resource costs	1,031,989	—	23,553	23,553	—	1,055,542
Other operating expenses	206,528	44,349	20,744	65,093	—	271,621
Depreciation and amortization	87,845	3,439	1,348	4,787	—	92,632
Income (loss) from operations	174,245	11,297	(631)	10,666	—	184,911
Interest expense (2)	79,401	110	157	267	(81)	79,587
Income taxes	41,527	4,067	31	4,098	—	45,625
Net income (loss) attributable to Avista Corporation	70,032	6,090	(2,502)	3,588	—	73,620
Capital expenditures	219,239	3,485	175	3,660	—	222,899
For the year ended December 31, 2007:						
Operating revenues	$ 1,288,363	$ 47,255	$ 82,139	$ 129,394	$ —	$ 1,417,757
Resource costs	780,998	—	68,676	68,676	—	849,674
Other operating expenses	198,778	33,841	33,942	67,783	—	266,561
Depreciation and amortization	86,091	2,402	2,157	4,559	—	90,650
Income (loss) from operations	150,053	11,012	(22,636)	(11,624)	—	138,429
Interest expense (2)	86,389	194	811	1,005	(954)	86,440
Income taxes	26,663	3,942	(6,271)	(2,329)	—	24,334
Net income (loss) attributable to Avista Corporation	43,822	6,651	(11,998)	(5,347)	—	38,475
Capital expenditures	205,811	2,323	957	3,280	—	209,091
Total Assets:						
As of December 31, 2009	$ 3,400,384	$ 143,060	$ 63,515	$ 206,575	—	$ 3,606,959
As of December 31, 2008	3,434,844	125,911	69,992	195,903	—	3,630,747

(1) *Intersegment eliminations reported as interest expense represent intercompany interest.*

(2) *Including interest expense to affiliated trusts.*

NOTE 28. 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 2009 and 2008 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2009				
Operating revenues	$ 487,470	$ 307,111	$ 314,692	$ 403,292
Operating expenses	421,625	249,029	290,938	350,315
Income from operations	$ 65,845	$ 58,082	$ 23,754	$ 52,977
Net income	$ 31,419	$ 26,289	$ 8,634	$ 22,305
Less: Net income attributable to noncontrolling interests	(393)	(437)	(495)	(252)
Net income attributable to Avista Corporation	$ 31,026	$ 25,852	$ 8,139	$ 22,053
Outstanding common stock:				
Weighted average, basic	54,616	54,654	54,706	54,796
End of period	54,643	54,671	54,741	54,837
Earnings per common share attributable to Avista Corporation, diluted	$ 0.57	$ 0.47	$ 0.15	$ 0.40
Dividends paid per common share	$ 0.18	$ 0.21	$ 0.21	$ 0.21
Trading price range per common share:				
High	$ 20.01	$ 18.13	$ 20.83	$ 22.44
Low	$ 12.67	$ 13.44	$ 17.59	$ 18.48
2008				
Operating revenues	$ 496,307	$ 350,310	$ 382,685	$ 447,461
Operating expenses	437,246	293,820	357,353	403,433
Income from operations	$ 59,061	$ 56,490	$ 25,332	$ 44,028
Net income	$ 25,364	$ 23,552	$ 7,828	$ 18,013
Less: Net income attributable to noncontrolling interests	(133)	(7)	(469)	(528)
Net income attributable to Avista Corporation	$ 25,231	$ 23,545	$ 7,359	$ 17,485
Outstanding common stock:				
Weighted average, basic	53,020	53,301	53,773	54,445
End of period	53,049	53,496	54,422	54,488
Earnings per common share attributable to Avista Corporation, diluted	$ 0.47	$ 0.44	$ 0.13	$ 0.32
Dividends paid per common share	$ 0.165	$ 0.165	$ 0.18	$ 0.18
Trading price range per common share:				
High	$ 21.39	$ 22.10	$ 23.30	$ 22.06
Low	$ 18.09	$ 19.86	$ 20.72	$ 16.58

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, 2009.

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, 2009 is effective.

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, 2009.

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, 2009, 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, 2009, 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, 2009 of the Company and our report dated February 26, 2010 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 26, 2010

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 13, 2010.

Executive Officers of the Registrant Name	Age	Business Experience
Scott L. Morris	52	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	46	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 — January 2008; Senior Vice President and Chief Financial Officer March 2000 — March 2003; Controller May 1997 — March 2000.
Marian M. Durkin	56	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 — August 2005, most recently served as Vice President Deputy General Counsel and Assistant Secretary.
Karen S. Feltes	54	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	48	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	53	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	51	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	54	Vice President since May 2004; Vice President of Transmission and Distribution Operations — Avista Utilities since May 2004; 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	56	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	51	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	59	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	39	Vice President of Finance since June 2009; various other management and staff positions with the Company since 1996.
Roger D. Woodworth	53	Vice President since November 1998; Vice President, Sustainable Energy Solutions — Avista Utilities since February 2007; Vice President, Customer Solutions — Avista Utilities March 2003 — February 2007; Vice President of Utility Operations — 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 2009. 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 13, 2010.

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 13, 2010.

(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 13, 2010.

(c) Changes in control:

None.

(d) Securities authorized for issuance under equity compensation plans as of December 31, 2009:

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)	299,400	$ 15.86	655,496
Equity compensation plans not approved by security holders (3)	224,573	$ 16.88	1,715,052
Total	523,973	$ 16.30	2,370,548

(1) Excludes unvested restricted shares and performance share awards granted under Avista Corp.'s Long Term Incentive Plan. At December 31, 2009, 71,904 Restricted Share awards were outstanding. Performance share awards may be paid out at zero shares at a minimum achievement level; 300,601 shares at target level; or 450,902 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 13, 2010.

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 13, 2010.

PART IV

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, 2009, 2008 and 2007

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2009, 2008 and 2007

Consolidated Balance Sheets as of December 31, 2009 and 2008

Consolidated Statements of Cash Flows for the Years Ended December 31, 2009, 2008 and 2007

Consolidated Statements of Equity for the Years Ended December 31, 2009, 2008 and 2007

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules:

None

(a) 3. Exhibits:

Reference is made to the Exhibit Index commencing on page 106. 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 26, 2010	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 26, 2010
/s/ Mark T. Thies Mark T. Thies (Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 26, 2010
/s/ Christy M. Burmeister-Smith Christy M. Burmeister-Smith (Vice President, Controller and Principal Accounting Officer)	Principal Accounting Officer	February 26, 2010
/s/ Erik J. Anderson Erik J. Anderson	Director	February 26, 2010
/s/ Kristianne Blake Kristianne Blake	Director	February 26, 2010
/s/ Brian W. Dunham Brian W. Dunham	Director	February 26, 2010
/s/ Roy L. Eiguren Roy L. Eiguren	Director	February 26, 2010
/s/ Jack W. Gustavel Jack W. Gustavel	Director	February 26, 2010
/s/ John F. Kelly John F. Kelly	Director	February 26, 2010
/s/ Michael L. Noël Michael L. Noël	Director	February 26, 2010
/s/ Marc Racicot Marc Racicot	Director	February 26, 2010
/s/ Heidi B. Stanley Heidi B. Stanley	Director	February 26, 2010
/s/ R. John Taylor R. John Taylor	Director	February 26, 2010

EXHIBIT INDEX

	Previously Filed[1]		
Exhibit	With Registration Number	As Exhibit	
3(i)	1-3701 (with June 30, 2008 Form 10-Q)	3(i)	Restated Articles of Incorporation of Avista Corporation as amended and restated June 6, 2008.
3(ii)	1-3701 (with Form 8-K as of May 9, 2008)	3(ii)	Bylaws of Avista Corporation, as amended May 9, 2008.
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.

	Previously Filed[1]		
Exhibit	With Registration Number	As Exhibit	
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.
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.

EXHIBIT INDEX (CONTINUED)

Exhibit	Previously Filed[1] With Registration Number	As Exhibit	
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.
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, 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.
4.50	333-82165	4(a)	Indenture dated as of April 1, 1998 between Avista Corporation and The Bank of New York, as Successor Trustee.

	Previously Filed (1)		
Exhibit	With Registration Number	As Exhibit	
4.51	1-3701 (with Form 8-K dated as of May 12, 2005)	4.2	First Supplemental Loan Agreement between City of Forsyth, Montana, and Avista Corporation, dated as of May 1, 2005, relating to $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 1999A.
4.52	1-3701 (with Form 8-K dated as of May 12, 2005)	4.3	First Supplemental Trust Indenture between City of Forsyth, Montana, and J.P. Morgan Trust Company, N.A. (successor in interest to Chase Manhattan Bank and Trust Company, National Association) as Trustee, dated as of May 1, 2005, relating to $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 1999A.
4.53	1-3701 (with Form 8-K dated as of May 12, 2005)	4.6	Loan Agreement, Restated as of May 1, 2005, between City of Forsyth, Montana and Avista Corporation, relating to $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 1999A.
4.54	1-3701 (with Form 8-K dated as of May 12, 2005)	4.7	Trust Indenture, Restated as of May 1, 2005, between City of Forsyth, Montana and J. P. Morgan Trust Company, N.A. (successor in interest to Chase Manhattan Bank and Trust Company, N.A.) as Trustee, relating to $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 1999A.
4.55	1-3701 (with Form 8-K dated as of December 30, 2008)	4.1	Loan Agreement between City of Forsyth, Montana, and Avista Corporation, dated as of December 1, 2008 relating to $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2008.
4.56	1-3701 (with Form 8-K dated as of December 30, 2008)	4.2	Trust Indenture between City of Forsyth, Montana, and Bank of New York Mellon Trust Company, N.A. as Trustee, dated as of December 1, 2008, relating to $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2008.
10.1	1-3701 (with Form 8-K dated as of December 15, 2004)	10.1	Credit Agreement, dated as of December 17, 2004 among Avista Corporation, the Banks listed therein, Bank of America, N.A., as Managing Agent, Keybank National Association and U.S. Bank, National Association, as Documentation Agents, Wells Fargo Bank, as Documentation Agent and an Issuing Bank, Union Bank of California, N.A., as Syndication Agent and an Issuing Bank, and The Bank of New York, as Administrative Agent and an Issuing Bank.
10.2	1-3701 (with Form 8-K dated as of April 6, 2006)	10.1	Amendment No. 1, dated as of April 6, 2006, to and under the Credit Agreement, dated as of December 17, 2004, among Avista Corporation, the Banks party thereto, Bank of America, N.A., as Managing Agent, Keybank National Association and U.S. Bank, National Association, as Documentation Agents, Wells Fargo Bank, as Documentation Agent and an Issuing Bank, Union Bank of California, N.A., as Syndication Agent and an Issuing Bank, and The Bank of New York, as Administrative Agent and an Issuing Bank.

Exhibit	Previously Filed (1) With Registration Number	As Exhibit	
10.3	1-3701 (with 2008 Form 10-K)	10.3	Amendment No. 2, dated as of December 19, 2008, to and under the Credit Agreement, dated as of December 17, 2004, among Avista Corporation, the Banks party thereto, Bank of America, N.A., as Managing Agent, Keybank National Association and U.S. Bank, National Association, as Documentation Agents, Wells Fargo Bank, as Documentation Agent and an Issuing Bank, Union Bank of California, N.A., as Syndication Agent and an Issuing Bank, and The Bank of New York Mellon f/k/a The Bank of New York, as Administrative Agent and an Issuing Bank.
10.4	1-3701 (with Form 8-K dated as of December 15, 2004)	10.2	Bond Delivery Agreement, dated as of December 17, 2004, between Avista Corporation and The Bank of New York.
10.5	1-3701 (with June 30, 2002 Form 10-Q)	4(e)	Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corp., as Seller, Avista Corporation, as initial Servicer and Eaglefunding Capital Corporation, as Conduit Purchaser and Fleet National Bank, as Committed Purchaser and Fleet Securities, Inc. as Administrator.
10.6	1-3701 (with 2004 Form 10-K)	4(d)-1	Amendment No. 1 to Receivables Purchase Agreement.
10.7	1-3701 (with 2004 Form 10-K)	4(d)-2	Amendment No. 2 to Receivables Purchase Agreement.
10.8	1-3701 (with Form 8-K dated March 22, 2005)	10.1	Amendment No. 3, dated as of March 22, 2005, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Administrator.
10.9	1-3701 (with Form 8-K dated March 20, 2006)	10.1	Amendment No. 4, dated as of March 20, 2006, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Administrator.
10.10	1-3701 (with March 31, 2006 Form 10-Q)	10.1	Amendment No. 5, dated as of May 4, 2006, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Administrator.
10.11	1-3701 (with Form 8-K dated March 19, 2007)	10.1	Amendment No. 6, dated as of March 19, 2007, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Administrator.

	Previously Filed (1)		
Exhibit	With Registration Number	As Exhibit	
10.12	1-3701 (with Form 8-K dated March 14, 2008)	10.1	Amendment No. 7, dated as of March 14, 2008, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Administrator.
10.13	1-3701 (with Form 8-K dated March 13, 2009)	10.1	Amendment No. 8, dated as of March 13, 2009, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Administrator and appendix A.
10.14	1-3701 (with Form 8-K dated as of November 25, 2009)	10.1	Credit Agreement, dated as of November 25, 2009 among Avista Corporation, the Banks party thereto, JPMorgan Chase Bank, N.A. and UBS Securities LLC, as Co-Documentation Agents, Wells Fargo Securities, LLC, as Syndication Agent, and Union Bank, N.A., as Administrative Agent.
10.15	2-13788	13(e)	Power Sales Contract (Rocky Reach Project) with Public Utility District No. 1 of Chelan County, Washington, dated as of November 14, 1957.
10.16	2-60728	10(b)-1	Amendment to Power Sales Contract (Rocky Reach project) with Public Utility District No. 1 of Chelan County, Washington, dated as of June 1, 1968.
10.17	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).
10.18	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).
10.19	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).
10.20	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.
10.21	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.
10.22	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.

	Previously Filed [1]		
Exhibit	With Registration Number	As Exhibit	
10.23	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.
10.24	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.
10.25	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.
10.26	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.
10.27	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.
10.28	1-3701 (with June 30, 2007 Form 10-Q)	10.1	Indemnification Agreement entered into as of June 30, 2007 by Coral Energy Holding, L.P. and certain of its affiliates and Avista Energy, Inc. and certain of its affiliates.
10.29	1-3701 (with June 30, 2007 Form 10-Q)	10.2	Guaranty Agreement effective as of June 30, 2007 entered into by Avista Capital, Inc. in favor of Coral Energy Holding, L.P. and certain of its affiliates.
10.30	1-3701 (with 2008 Form 10-K)	10.33	Executive Deferral Plan of the Company. [3][5]
10.31	1-3701 (with 2008 Form 10-K)	10.34	The Company's Unfunded Supplemental Executive Retirement Plan. [3][5]
10.32	1-3701 (with 1992 Form 10-K)	10(t)-11	The Company's Unfunded Supplemental Executive Disability Plan. [3]
10.33	1-3701 (with 2007 Form 10-K)	10.34	Income Continuation Plan of the Company. [3]
10.34	1-3701 (with 2006 Form 10-K)	10.37	Avista Corporation Long-Term Incentive Plan. [3]
10.35	1-3701 (with 2004 Form 10-K)	10(o)-6	Avista Corp. Performance Award Plan Summary. [3]
10.36	1-3701 (with 2004 Form 10-K)	10(o)-7	Avista Corporation Performance Award Agreement. [3]
10.37	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]

	Previously Filed [1]		
Exhibit	With Registration Number	As Exhibit	
10.38	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]
10.39	333-47290	99.1	Non-Officer Employee Long-Term Incentive Plan.
10.40	1-3701 (with 2008 Form 10-K)	10.44	Form of Change of Control Agreement between the Company and its Executive Officers. [3][5][6]
10.41	1-3701 (with 2008 Form 10-K)	10.45	Form of Change of Control Agreement between the Company and its Executive Officers. [3][5][7]
10.42	1-3701 (with September 30, 2007 Form 10-Q)	10.1	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).
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).

(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) *The plans were modified to comply with Section 409A of the Internal Revenue Code. No significant changes were made to the plans.*

(6) *Applies for 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.*

(7) *Applies for Marian M. Durkin, Karen S. Feltes, Scott L. Morris, and Mark T. Thies.*

EXHIBIT 12

Avista Corporation

Computation of Ratio of Earnings to Fixed Charges

Consolidated

(Thousands of Dollars)

Years Ended December 31,

	2009	2008	2007	2006	2005
Fixed charges, as defined:					
Interest charges	$ 61,361	$ 74,914	$ 80,095	$ 88,426	$ 84,952
Amortization of debt expense and premium – net	5,673	4,673	6,345	7,741	7,762
Interest portion of rentals	1,874	1,601	1,612	1,802	2,394
Total fixed charges	$ 68,908	$ 81,188	$ 88,052	$ 97,969	$ 95,108
Earnings, as defined:					
Pre-tax income from continuing operations	$ 134,971	$ 120,382	$ 63,061	$ 114,927	$ 70,752
Add (deduct):					
Capitalized interest	(545)	(4,612)	(3,864)	(2,934)	(1,689)
Total fixed charges above	68,908	81,188	88,052	97,969	95,108
Total earnings	$ 203,334	$ 196,958	$ 147,249	$ 209,962	$ 164,171
Ratio of earnings to fixed charges	2.95	2.43	1.67	2.14	1.73

EXHIBIT 21

Avista Corporation

SUBSIDIARIES OF REGISTRANT

Subsidiary	State or Country of Incorporation
Avista Capital, Inc.	Washington
Advantage IQ, 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
Bay Area Manufacturing, Inc.	Washington
Advanced Manufacturing and Development, Inc.	California
Avista Receivables Corporation	Washington
Avista Capital II	Delaware
Spokane Energy, LLC	Delaware
Steam Plant Square, LLC	Washington
Courtyard Office Center, LLC	Washington
Ecos IQ, Inc.	Washington

EXHIBIT 23

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, 333-58197, 333-33790, 333-47290, and 333-126577 on Form S-8; and in Registration Statement Nos. 033-53655, 333-63243, 333-64652, and 333-155657, and 333-163609 on Form S-3 of our reports dated February 26, 2010, relating to the consolidated financial statements of Avista Corporation and subsidiaries, and the effectiveness of Avista Corporation and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K of Avista Corporation for the year ended December 31, 2009.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 26, 2010

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 26, 2010

/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 26, 2010

/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, 2009 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 26, 2010

/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

SELECTED FINANCIAL DATA

Avista Corporation
As of and for the years ended December 31,
Dollars in thousands, except per share data and ratios

	2009	2008	2007	2006	2005	1999
Financial Results						
Operating revenues	$ 1,512,565	$ 1,676,763	$ 1,417,757	$ 1,506,311	$ 1,359,607	$ 1,229,093
Operating expenses	1,311,907	1,491,852	1,279,328	1,306,751	1,211,953	1,189,776
Gain on sale of utility properties	—	—	—	—	4,093	—
Income from operations	200,658	184,911	138,429	199,560	151,747	39,317
Interest expense	67,034	79,587	86,440	96,167	92,714	64,747
Income taxes	46,323	45,625	24,334	41,986	25,764	18,276
Income from continuing operations	88,648	74,757	38,727	72,941	44,988	31,223
Loss from discontinued operations	—	—	—	—	—	(5,192)
Net income	88,648	74,757	38,727	72,941	44,988	26,031
Net income attributable to noncontrolling interests	(1,577)	(1,137)	(252)	—	—	—
Preferred stock dividend requirements (1)	—	—	—	—	—	21,392
Net income attributable to Avista Corporation	$ 87,071	$ 73,620	$ 38,475	$ 72,941	$ 44,988	$ 4,639
Earnings per common share attributable to Avista Corporation, diluted:						
Earnings from continuing operations	$ 1.58	$ 1.36	$ 0.72	$ 1.46	$ 0.92	$ 0.26
Loss from discontinued operations	—	—	—	—	—	(0.14)
Total	$ 1.58	$ 1.36	$ 0.72	$ 1.46	$ 0.92	$ 0.12
Earnings per common share attributable to Avista Corporation, basic:	$ 1.59	$ 1.37	$ 0.73	$ 1.48	$ 0.93	$ 0.12
Common Stock Statistics						
Dividends paid per common share	$ 0.810	$ 0.690	$ 0.595	$ 0.570	$ 0.545	$ 0.48
Book value per common share	$ 19.17	$ 18.30	$ 17.27	$ 17.41	$ 15.82	$ 11.04
Shares of common stock:						
Outstanding at year-end	54,837	54,488	52,909	52,514	48,593	35,648
Average — basic	54,694	53,637	52,796	49,162	48,523	38,213
Average — diluted	54,942	54,028	52,263	49,897	48,979	38,325
Return on average Avista Corporation stockholders' equity:						
Total company	8.5%	7.7%	4.2%	8.7%	5.9%	1.1%
Utility only	9.2%	8.0%	5.8%	9.6%	10.2%	20.0%
Non-utility only	0.4%	4.9%	-3.4%	6.2%	-3.0%	-13.3%
Common stock price:						
High	$ 22.44	$ 23.30	$ 25.81	$ 27.52	$ 20.20	$ 19.56
Low	$ 12.67	$ 16.58	$ 18.19	$ 17.61	$ 16.31	$ 14.63
Year-end close	$ 21.59	$ 19.38	$ 21.54	$ 25.31	$ 17.71	$ 15.44

(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.*

SELECTED FINANCIAL DATA

Avista Corporation
As of and for the years ended December 31,
Dollars in thousands, except per share data and ratios

	2009	2008	2007	2006	2005	1999
Debt and Preferred Stock Statistics (Avista Corp. Only)						
Pretax interest coverage:						
Including AFUDC/AFUCE	2.97(x)	2.45(x)	1.75(x)	2.11(x)	1.84(x)	1.97(x)
Excluding AFUDC/AFUCE	2.92(x)	2.32(x)	1.65(x)	2.06(x)	1.80(x)	1.93(x)
Embedded cost of long-term debt	5.91%	6.69%	7.84%	7.79%	8.09%	6.95%
Embedded cost of preferred stock	— %	— %	— %	7.39%	7.39%	7.39%
Credit Ratings (Standard & Poor's/Moody's)						
Senior secured debt	BBB+/Baa1	BBB+/Baa2	BBB+/Baa2	BBB-/Baa3	BBB-/Baa3	BBB+/A3
Senior unsecured debt	N/A/Baa3	BBB-/Baa3	BBB-/Baa3	BB+/Ba1	BB+/Ba1	BBB/Baa1
Financial Condition						
Total assets	$ 3,606,959	$ 3,630,747	$ 3,189,797	$ 4,056,508	$ 4,948,494	$ 3,875,384
Total net utility property	2,607,011	2,492,191	2,351,342	2,215,037	2,126,417	1,662,727
Utility property capital expenditures (excluding equity-related AFUDC)	205,384	219,239	205,811	161,266	215,341	87,160
Long-term debt (including current portion)	1,071,338	826,465	948,833	976,459	1,029,514	714,904
Long-term debt to affiliated trusts	51,547	113,403	113,403	113,403	113,403	110,000
Preferred stock subject to mandatory redemption [1]	—	—	—	26,250	28,000	35,000
Convertible preferred stock	—	—	—	—	—	263,309
Avista Corporation stockholders' equity	$ 1,051,287	$ 996,883	$ 913,966	$ 914,525	$ 768,849	$ 399,499

(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,

	2009	2008	2007	2006	2005	1999
Avista Utilities						
Electric Operations						
Electric operating revenues (millions of dollars):						
Residential	$ 315.7	$ 279.6	$ 251.4	$ 234.7	$ 211.9	$ 158.6
Commercial	274.0	247.7	224.2	221.2	203.5	152.1
Industrial	107.7	101.8	95.2	92.9	91.6	69.6
Public street and highway lighting	6.6	6.0	5.5	5.3	4.9	3.5
Total retail	704.0	635.1	576.3	554.1	511.9	383.8
Wholesale	88.4	141.8	105.7	126.2	151.4	522.5
Sales of fuel	33.0	44.7	12.9	48.2	41.8	1.0
Other	15.4	16.9	16.2	18.9	18.0	20.9
Total electric operating revenues	$ 840.8	$ 838.5	$ 711.1	$ 747.4	$ 723.1	$ 928.2
Electric energy sales (millions of kWhs):						
Residential	3,791	3,744	3,670	3,578	3,420	3,237
Commercial	3,177	3,188	3,132	3,110	2,994	2,848
Industrial	1,948	2,059	2,084	2,062	2,091	2,032
Public street and highway lighting	26	26	26	25	25	25
Total retail	8,942	9,017	8,912	8,775	8,530	8,142
Wholesale	2,354	1,964	1,594	2,117	2,508	19,778
Total electric energy sales	11,296	10,981	10,506	10,892	11,038	27,920
Retail electric customers (average per year):						
Residential	313,884	311,381	306,737	300,940	294,036	270,013
Commercial	39,276	39,075	38,488	37,912	37,282	34,877
Industrial	1,394	1,388	1,378	1,388	1,408	1,189
Public street and highway lighting	444	434	426	425	421	389
Total retail electric customers	354,998	352,278	347,029	340,665	333,147	306,468
Retail electric customers (at year-end):						
Residential	315,297	313,660	310,701	305,293	298,961	272,342
Commercial	39,408	39,173	39,001	38,362	37,587	35,197
Industrial	1,384	1,384	1,383	1,378	1,393	1,078
Public street and highway lighting	447	440	427	417	428	395
Total retail electric customers	356,536	354,657	351,512	345,450	338,369	309,012
Revenue per residential kWh (cents)	8.33	7.47	6.85	6.56	6.20	4.90
Use per residential customer (kWh)	12,079	12,023	11,965	11,888	11,630	11,990
Revenue per commercial kWh (cents)	8.62	7.77	7.16	7.11	6.80	5.34
Use per commercial customer (kWh)	80,881	81,583	81,377	82,028	80,314	81,662
Electric energy resources (millions of kWhs):						
Hydro generation (from Company facilities)	3,766	3,851	3,689	4,128	3,611	4,286
Thermal generation (from Company facilities)	3,097	3,693	3,640	3,434	3,666	3,353
Purchased power — long-term hydro contracts	839	833	861	787	864	1,093
Purchased power — wholesale	4,152	3,253	2,959	3,101	3,519	19,697
Power exchanges	(18)	(17)	(18)	35	10	16
Total power resources	11,836	11,613	11,131	11,485	11,670	28,445
Energy losses and company use	(540)	(632)	(625)	(593)	(632)	(525)
Total electric energy resources	11,296	10,981	10,506	10,892	11,038	27,920

SELECTED FINANCIAL DATA

Avista Corporation
As of and for the years ended December 31,

	2009	2008	2007	2006	2005	1999
Electric Operations (continued)						
Total resources available at peak (MW):						
Company owned:						
Hydro	562	765	617	980	980	956
Thermal	781	724	830	837	836	685
Purchased power:						
Long-term hydro contracts	103	132	171	143	70	180
Other	1,068	859	684	658	670	3,010
Total resources available at peak (winter)	2,514	2,480	2,302	2,618	2,556	4,831
Net system peak demand (winter)	1,763	1,821	1,685	1,656	1,660	1,421
Wholesale obligations	608	562	367	431	282	3,211
Total requirements (winter)	2,371	2,383	2,052	2,087	1,942	4,632
Reserve margin	6%	4%	11%	20%	24%	4%
Annual load factor	61%	62%	61%	59%	56%	70%
Natural Gas Operations						
Natural gas operating revenues (millions of dollars):						
Residential	$ 251.0	$ 276.4	$ 264.5	$ 257.8	$ 229.7	$ 99.9
Commercial	135.2	152.1	148.4	146.6	126.6	51.9
Industrial and interruptible	10.0	12.2	11.3	11.7	11.9	5.1
Total retail	396.2	440.7	424.2	416.1	368.2	156.9
Wholesale	143.5	281.7	142.2	93.2	58.1	15.2
Transportation	6.1	6.3	6.6	6.5	7.6	10.8
Other	8.6	5.5	4.2	4.8	4.3	4.6
Total natural gas operating revenues	$ 554.4	$ 734.2	$ 577.2	$ 520.6	$ 438.2	$ 187.5
Natural gas therms delivered (millions of therms):						
Residential	208.0	210.1	195.7	192.8	199.4	200.2
Commercial	126.3	128.2	121.6	121.0	123.0	125.6
Industrial and interruptible	10.9	12.2	10.8	11.0	13.5	16.4
Total retail	345.2	350.5	328.1	324.8	335.9	342.2
Wholesale	398.0	345.9	223.1	154.9	72.9	74.1
Transportation and other	145.1	149.3	149.2	150.2	153.5	242.6
Total natural gas therms delivered	888.3	845.7	700.4	629.9	562.3	658.9
Retail natural gas customers (average per year):						
Residential	280,667	277,892	273,415	267,345	265,294	234,844
Commercial	33,214	32,901	32,327	31,746	31,652	29,032
Industrial and interruptible	300	297	302	295	307	338
Total retail natural gas customers	314,181	311,090	306,044	299,386	297,253	264,214
Retail natural gas customers (at year-end):						
Residential	282,538	280,687	277,397	272,109	265,502	239,321
Commercial	33,369	33,123	32,840	32,173	31,476	29,432
Industrial and interruptible	294	292	298	304	299	332
Total retail natural gas customers	316,201	314,102	310,535	304,586	297,277	269,085

Avista Corporation
As of and for the years ended December 31,

	2009	2008	2007	2006	2005	1999
Natural Gas Operations (continued)						
Revenue per residential therm (in dollars)	1.21	1.32	1.35	1.34	1.15	0.50
Use per residential customer (therms)	741	756	716	721	752	852
Revenue per commercial therm (in dollars)	1.07	1.19	1.22	1.21	1.03	0.41
Use per commercial customer (therms)	3,804	3,897	3,760	3,811	3,885	4,327
Heating degree days (at Spokane, Washington):						
Actual	6,976	7,052	6,539	6,332	6,538	6,408
30 year average	6,820	6,820	6,820	6,820	6,820	6,842
Actual as a percent of average	102%	103%	96%	93%	96%	94%
Advantage IQ						
Revenues (millions of dollars)	$ 77.3	$ 59.1	$ 47.3	$ 39.6	$ 31.7	$ 1.5
Total assets (millions of dollars)	$ 143.1	$ 125.9	$ 108.9	$ 100.4	$ 46.1	$ 3.9
Other						
Revenues (millions of dollars)	$ 40.1	$ 45.0	$ 82.1	$ 198.7	$ 185.9	$ 140.6
Total assets (millions of dollars)	$ 63.5	$ 70.0	$ 71.4	$ 1,060.2	$ 2,064.3	$ 1,710.4

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
BNY Mellon 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/isd

Stock Inquiries Should Be Directed to:
Avista Corp.
c/o BNY Mellon Shareowner Services
P.O. Box 358015
Pittsburgh, PA 15252-8015
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 13, 2010, at Avista Corp. headquarters, 1411 East Mission Avenue, Spokane, Washington.

The annual meeting also 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 28, 2009, 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 2009, 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 2009. Our 2009 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 2009 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 and Ross 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.

AVISTA Corp.

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