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, 2012 OR

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

Commission file number 1-3701

AVISTA CORPORATION

(Exact name of Registrant as specified in its charter)

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

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

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

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

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

Title of Class
Preferred Stock, Cumulative, Without Par Value

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

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

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

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

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

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

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

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

The aggregate market value of the Registrant’s outstanding Common Stock, no par value (the only class of voting stock), held by non-affiliates is $1,568,836,865 based on the last reported sale price thereof on the consolidated tape on June 30, 2012.

As of January 31, 2013, 59,851,338 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 on May 9, 2013	**Part III, Items 10, 11, 12, 13 and 14**

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* = not an applicable item in the 2012 calendar year for Avista Corp.

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

Acronym/Term		Meaning
aMW	-	Average Megawatt - a measure of the average rate at which a particular generating source produces energy over a period of time
AFUDC	-	Allowance for Funds Used During Construction; represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period
AM&D	-	Advanced Manufacturing and Development, does business as METALfx
ASC	-	Accounting Standards Codification
Avista Capital	-	Parent company to the Company's non-utility businesses
Avista Corp.	-	Avista Corporation, the Company
Avista Energy	-	Avista Energy, Inc., an electricity and natural gas marketing, trading and resource management business, subsidiary of Avista Capital. This entity is currently inactive; however, we still incur legal fees associated with this entity.
Avista Utilities	-	Operating division of Avista Corp. comprising the regulated utility operations
BPA	-	Bonneville Power Administration
Capacity	-	The rate at which a particular generating source is capable of producing energy, measured in KW or MW
Cabinet Gorge	-	The Cabinet Gorge Hydroelectric Generating Project, located on the Clark Fork River in Idaho
Colstrip	-	The coal-fired Colstrip Generating Plant in southeastern Montana
Coyote Springs 2	-	The natural gas-fired Coyote Springs 2 Generating Plant located near Boardman, Oregon
CT	-	Combustion turbine
Deadband or ERM deadband	-	The first $4.0 million in annual power supply costs above or below the amount included in base retail rates in Washington under the Energy Recovery Mechanism in the state of Washington
Dekatherm	-	Unit of measurement for natural gas; a dekatherm is equal to approximately one thousand cubic feet (volume) or 1,000,000 BTUs (energy)
Ecology	-	The state of Washington's Department of Ecology
Ecova	-	Ecova, Inc., a provider of facility information and cost management services for multi-site customers and energy efficiency program management for commercial enterprises and utilities throughout North America, subsidiary of Avista Capital. Formerly known as Advantage IQ, Inc. (Advantage IQ)
Energy	-	The amount of electricity produced or consumed over a period of time, measured in KWH or MWH. Also, refers to natural gas consumed and is measured in dekatherms.
EPA	-	Environmental Protection Agency
ERM	-	The Energy Recovery Mechanism, a mechanism for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Washington
FASB	-	Financial Accounting Standards Board
FERC	-	Federal Energy Regulatory Commission
GAAP	-	Generally Accepted Accounting Principles
GHG	-	Greenhouse gas
IPUC	-	Idaho Public Utilities Commission
IRP	-	Integrated Resource Plan
Jackson Prairie	-	Jackson Prairie Natural Gas Storage Project, an underground natural gas storage field located near Chehalis, Washington
kV	-	Kilovolt (1000 volts): a measure of capacity on transmission lines
KW, KWH	-	Kilowatt (1000 watts): a measure of generating output or capability. Kilowatt-hour (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: 1000 KW. Megawatt-hour: 1000 KWH
NERC	-	North American Electricity Reliability Corporation

Noxon Rapids	-	The Noxon Rapids Hydroelectric Generating Project, located on the Clark Fork River in Montana
OPUC	-	The Public Utility Commission of Oregon
PCA	-	The Power Cost Adjustment mechanism, a procedure for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Idaho
PGA	-	Purchased Gas Adjustment
PLP	-	Potentially liable party
PUD	-	Public Utility District
PURPA	-	The Public Utility Regulatory Policies Act of 1978, as amended
RTO	-	Regional Transmission Organization
Spokane Energy	-	Spokane Energy, LLC, a special purpose limited liability company and all of its membership capital is owned by Avista Corp.
Spokane River Project	-	The five hydroelectric plants operating under one FERC license on the Spokane River (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls)
Therm	-	Unit of measurement for natural gas; a therm is equal to approximately one hundred cubic feet (volume) or 100,000 BTUs (energy)
UTC	-	Washington Utilities and Transportation Commission
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

Forward-Looking Statements

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

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

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

- weather conditions (temperatures, precipitation levels and wind patterns) which affect energy demand and electric generation, including the effect of precipitation and temperature on hydroelectric resources, the effect of wind patterns on wind-generated power, weather-sensitive customer demand, and similar impacts on supply and demand in the wholesale energy markets;
- state and federal regulatory decisions that affect our ability to recover costs and earn a reasonable return including, but not limited to, disallowance or delay in the recovery of capital investments and operating costs;
- changes in wholesale energy prices that can affect operating income, cash requirements to purchase electricity and natural gas, value received for wholesale sales, collateral required of us by counterparties on wholesale energy transactions and credit risk to us from such transactions, and the market value of derivative assets and liabilities;
- economic conditions in our service areas, including customer demand for utility services;
- the effect of increased customer energy efficiency;
- our ability to obtain financing through the issuance of debt and/or equity securities, which can be affected by various factors including our credit ratings, interest rates and other capital market conditions and the global economy;
- the potential effects of legislation or administrative rulemaking, including possible effects on our generating resources of restrictions on greenhouse gas emissions to mitigate concerns over global climate changes;
- changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension and other postretirement medical plans, which can affect future funding obligations, pension and other postretirement medical expense and pension and other postretirement medical plan liabilities;
- volatility and illiquidity in wholesale energy markets, including the availability of willing buyers and sellers, and prices of purchased energy and demand for energy sales;
- the outcome of pending regulatory and legal proceedings arising out of the "western energy crisis" of 2000 and 2001, including possible refunds;
- the outcome of legal proceedings and other contingencies;
- changes in, and compliance with, environmental and endangered species laws, regulations, decisions and policies, including present and potential environmental remediation costs;

- wholesale and retail competition including alternative energy sources, suppliers and delivery arrangements and the extent that new uses for our services may materialize;
- the ability to comply with the terms of the licenses for our hydroelectric generating facilities at cost-effective levels;
- severe weather or natural disasters that can disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies and support services;
- explosions, fires, accidents, mechanical breakdowns, or other incidents that may cause unplanned outages at any of our generation facilities, transmission and distribution systems or other operations;
- public injuries or damages arising from or allegedly arising from our operations;
- blackouts or disruptions of interconnected transmission systems (the regional power grid);
- disruption to information systems, automated controls and other technologies that we rely on for operations, communications and customer service;
- terrorist attacks, cyber attacks or other malicious acts that may disrupt or cause damage to our utility assets or to the national economy in general, including any effects of terrorism, cyber attacks or vandalism that damage or disrupt information technology systems;
- delays or changes in construction costs, and/or our ability to obtain required permits and materials for present or prospective facilities;
- changes in the costs to implement new information technology systems and/or obstacles that impede our ability to complete such projects timely and effectively;
- changes in the long-term climate of the Pacific Northwest, which can affect, among other things, customer demand patterns and the volume and timing of streamflows to our hydroelectric resources;
- changes in industrial, commercial and residential growth and demographic patterns in our service territory or changes in demand by significant customers;
- the loss of key suppliers for materials or services;
- default or nonperformance on the part of any parties from which we purchase and/or sell capacity or energy;
- deterioration in the creditworthiness of our customers;
- potential decline in our credit ratings, with effects including impeded access to capital markets, higher interest costs, and certain ratings trigger covenants in our financing arrangements and wholesale energy contracts;
- increasing health care costs and the resulting effect on health insurance provided to our employees and retirees;
- increasing costs of insurance, more restricted coverage terms and our ability to obtain insurance;
- work force issues, including changes in collective bargaining unit agreements, strikes, work stoppages or the loss of key executives, availability of workers in a variety of skill areas, and our ability to recruit and retain employees;
- the potential effects of negative publicity regarding business practices - whether true or not - which could result in litigation or a decline in our common stock price;
- changes in technologies, possibly making some of the current technology obsolete;
- changes in tax rates and/or policies;
- changes in the payment acceptance policies of Ecova’s client vendors that could reduce operating revenues;
- potential difficulties for Ecova in integrating acquired operations and in realizing expected opportunities, diversions of management resources and losses of key employees, challenges with respect to operating new businesses and other unanticipated risks and liabilities; and
- changes in our strategic business plans, which may be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses.

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

Available Information

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

PART I

Item 1. Business

Company Overview

Avista Corporation (Avista Corp. or the Company), incorporated in the state of Washington in 1889, is an energy company engaged in the generation, transmission and distribution of energy as well as other energy-related businesses. As of December 31, 2012, we employed 1,682 people in our utility operations (prior to the voluntary severance incentive program, which resulted in the termination of 55 employees effective at the end of the day on December 31, 2012) and 1,497 people in our subsidiary businesses. See "Note 4 of the Notes to Consolidated Financial Statements" for further discussion of the voluntary severance incentive program. Our corporate headquarters are in Spokane, Washington, the second-largest city in Washington. Spokane serves as the business, transportation, medical, industrial and cultural hub of the Inland Northwest region (eastern Washington and northern Idaho). Regional services include government and higher education, medical services, retail trade and finance. The Inland Northwest also coincides closely with our utility service area in Washington and Idaho. Our gas utility operations also include separate service areas in southwestern Oregon.

We have two reportable business segments as follows:

- **Avista Utilities** – an operating division of Avista Corp. that comprises our regulated utility operations. Avista Utilities generates, transmits and distributes electricity and distributes natural gas. The utility also engages in wholesale purchases and sales of electricity and natural gas.
- **Ecova** – an indirect subsidiary of Avista Corp. (79.0 percent owned as of December 31, 2012) provides energy efficiency and cost management programs and services for multi-site customers and utilities throughout North America. Ecova's service lines include expense management services for utility and telecom needs as well as strategic energy management and efficiency services that include procurement, conservation, performance reporting, financial planning, facility optimization and continuous monitoring, and energy efficiency program management for commercial enterprises and utilities.

We have other businesses, including a sheet metal fabrication business, emerging technology venture fund investments and commercial real estate investments, as well as Spokane Energy, LLC (Spokane Energy). These activities do not represent a reportable business segment and are conducted by various indirect subsidiaries of Avista Corp.

Ecova and various other companies are subsidiaries of Avista Capital, Inc. (Avista Capital) which is a direct, wholly owned subsidiary of Avista Corp. Total Avista Corp. stockholders' equity was $1,259.5 million as of December 31, 2012, of which $118.7 million represented our investment in Avista Capital. Additionally, Ecova represents $73.9 million of our investment in Avista Capital.

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

Avista Utilities

General

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

Our utility provides electric distribution and transmission, as well as natural gas distribution services in parts of eastern Washington and northern Idaho. We also provide natural gas distribution service in parts of northeastern and southwestern Oregon. At the end of 2012, we supplied retail electric service to 362,000 customers and retail natural gas service to 323,000 customers across our entire service territory. Our service territory covers 30,000 square miles with a population of 1.5 million. See “Item 2. Properties” for further information on our utility assets. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Economic Conditions and Utility Load Growth” for information on economic conditions in our service territory.

Electric Operations

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

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

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

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

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

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

Our generation assets are interconnected through the regional transmission system and are operated on a coordinated basis to enhance load-serving capability and reliability. We provide transmission and ancillary services in eastern Washington, northern Idaho and western Montana. Transmission revenues were $12.7 million in 2012, $13.8 million in 2011 and $12.8 million in 2010.

Electric Requirements

Our peak electric native load requirement for 2012 occurred on August 7, 2012 at which time our total obligation was 2,485 MW consisting of:

- native load of 1,579 MW,

- long-term wholesale obligations of 236 MW, and
- short-term wholesale obligations of 670 MW.

At that time our maximum resource capacity available was 3,060 MW, which included:

- company-owned or controlled electric generation of 1,755 MW,
- long-term hydroelectric contracts with certain Public Utility Districts (PUDs) of 152 MW,
- long-term thermal generation contract with Lancaster Plant of 270 MW,
- other long-term wholesale contracts of 133 MW, and
- short-term wholesale purchases of 750 MW.

Historically, our peak electric native load requirement has occurred during the winter months; however, due to a weather anomaly in 2012, the peak electric native load requirement occurred during the summer period. We expect our peak electric native load requirement to occur in winter periods in the future.

Electric Resources

We have a diverse electric resource mix of Company-owned and contracted hydroelectric projects, thermal generating facilities, wind generation facilities, and power purchases and exchanges.

At the end of 2012, our Company-owned facilities had a total net capability of 1,844 MW, of which 55 percent was hydroelectric and 45 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 2013 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 534 average megawatts (aMW) (or 4.7 million MWhs). Hydroelectric resources provided 583 aMW for 2012, 637 aMW for 2011 and 477 aMW for 2010.

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

	2012	2011	2010
Noxon Rapids	1,823	2,110	1,503
Cabinet Gorge	1,199	1,292	942
Post Falls	83	90	90
Upper Falls	60	73	71
Monroe Street	102	110	106
Nine Mile	106	90	101
Long Lake	513	556	480
Little Falls	202	213	201
Total company-owned hydroelectric generation	4,088	4,534	3,494
Long-term hydroelectric contracts with PUDs	1,022	1,047	685
Total hydroelectric generation	5,110	5,581	4,179

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 northeastern 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 bilateral renewal rights.

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

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

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

See "Item 2 Properties - Avista Utilities - Generation Properties" for the nameplate rating and present generating capabilities of the above thermal resources.

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

	2012	2011	2010
Coyote Springs 2	1,142	705	1,661
Colstrip	1,499	1,433	1,749
Kettle Falls GS	209	291	312
Northeast CT and Rathdrum CT	7	8	12
Boulder Park and Kettle Falls CT	7	10	14
Total company-owned thermal generation	2,864	2,447	3,748
Long-term contract with Lancaster Plant	1,208	835	1,410
Total thermal generation	4,072	3,282	5,158

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

Palouse Wind PPA In June 2011, we entered into a 30-year PPA with Palouse Wind, LLC (Palouse Wind), an affiliate of First Wind Holdings, LLC. Under the PPA, we acquire all of the power and renewable attributes produced by a wind project that was developed by Palouse Wind in Whitman County, Washington. The wind project has a nameplate capacity of approximately 105 MW and is expected to produce approximately 40 aMW. The project was completed and deliveries began during the fourth quarter of 2012. Generation from Palouse Wind was 61,450 MWhs in 2012. We have an annual option to purchase the wind project following the 10th anniversary of its December 2012 commercial operation date.

Other Purchases, Exchanges and Sales In addition to the resources described above, we purchase and sell power under various long-term contracts and we also enter into short-term purchases and sales. Further, pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA), as amended, we are required to purchase generation from qualifying facilities. This includes, among other resources, hydroelectric projects, cogeneration projects and wind generation projects at rates approved by the Washington Utilities and Transportation Commission (UTC) and the Idaho Public Utilities Commission (IPUC). Existing PURPA contracts expire at various times through 2022.

See “Avista Utilities Operating Statistics – Electric Operations – Electric Energy Resources” for annual quantities of purchased power, wholesale power sales and power from exchanges in 2012, 2011 and 2010. See “Electric Operations” for additional information with respect to the use of wholesale purchases and sales as part of our resource optimization process and also see "Future Resource Needs" for the magnitude of these power purchase and sales contracts in future periods.

Hydroelectric Licensing

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

The Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) and the Noxon Rapids Hydroelectric Generating Project (Noxon Rapids) are under one 45-year FERC license issued in March 2001. See "Cabinet Gorge Total Dissolved Gas Abatement Plan" in "Note 21 of the Notes to Consolidated Financial Statements" for discussion of dissolved atmospheric gas levels that exceed state of Idaho and federal water quality standards downstream of Cabinet Gorge during periods when we must divert excess river flows over the spillway and our mitigation plans and efforts.

Five of our six hydroelectric projects on the Spokane River (Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls) are under one 50-year FERC license issued in June 2009 and are referred to collectively as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. For further information see "Spokane River Licensing" in "Note 21 of the Notes to Consolidated Financial Statements."

Future Resource Needs

We have operational strategies to provide sufficient resources to meet our energy requirements under a range of operating conditions. These operational strategies consider the amount of energy needed, which varies widely because of the factors that influence demand over intra-hour, hourly, daily, monthly and annual durations. Our average hourly load was 1,075 aMW in 2012, 1,096 aMW in 2011 and 1,075 aMW in 2010. The following is a forecast of our average annual energy requirements and resources for 2013, 2014, 2015 and 2016:

Forecasted Electric Energy Requirements and Resources
(aMW)

	2013	2014	2015	2016
Requirements:				
System load (1)	1,067	1,054	1,067	1,079
Contracts for power sales	128	109	58	49
Total requirements	1,195	1,163	1,125	1,128
Resources:				
Company-owned and contract hydro generation (2)	534	535	504	504
Company-owned and contract thermal generation (3)	704	704	725	718
Other contracts for power purchases	194	162	161	160
Total resources	1,432	1,401	1,390	1,382
Surplus resources	237	238	265	254
Additional available energy (4)	149	153	139	154
Total surplus resources	386	391	404	408

(1) System load is reduced in 2013 because a large industrial customer will begin generating electricity to meet a portion of its own load after June 30, 2013. The full impact of this load change culminates in 2014 when load is reduced for 12 calendar months.

(2) The forecast assumes near normal hydroelectric generation (decline in 2015 and 2016 is due to changes in contracts with PUDs).

(3) Includes our long-term contract with the Lancaster Plant. Excludes Northeast CT and Rathdrum CT as these are considered peaking facilities and are generally not used to meet our base load requirements. We generally dispatch thermal resources when operating costs are lower than short-term wholesale market prices.

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

In August 2011, we filed our 2011 Electric Integrated Resource Plan (IRP) with the UTC and the IPUC. The IRP details projected growth in demand for energy and the new resources needed to serve customers over the next 20 years. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project.

Highlights of the 2011 IRP include:

- A contract for the 105 MW Palouse Wind, LLC project, which provides a new resource to serve our customers' increasing energy needs. Commercial operations began on December 13, 2012.
- An additional 42 aMW of wind or other renewable beginning in 2021.
- Energy efficiency measures are expected to save 310 aMW of cumulative energy over the 20-year IRP timeframe. This aggressive effort could reduce load growth to half of what it would be without these measures.
- 750 MW of new natural gas-fired generation facilities are anticipated in two or three increments between 2018 and 2031.
- Grid modernization programs are projected to save 5 aMW of energy by 2013.
- Transmission upgrades will be needed to deliver the energy from new generation resources to the distribution lines serving customers. We will continue to participate in regional efforts to expand the region's transmission system.

We are required to file an IRP every two years with the next IRP expected to be filed during the third quarter of 2013. Our resource strategy may change from the 2011 IRP based on market, legislative and regulatory developments, etc.

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

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

Natural Gas Operations

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

Market prices for natural gas, like other commodities, can be volatile. To provide reliable supply and to manage the impact of volatile prices on our customers, we procure natural gas through a diversified mix of spot market purchases, forward fixed price purchases, and derivative instruments 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.

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

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

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

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

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

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

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.

Natural Gas Pipeline Replacement In 2011, we began implementation of a plan to replace certain vintages of Aldyl A natural gas pipe within its distribution systems in Washington, Oregon and Idaho. In early 2012, we released our protocol report to each state Commission describing our Aldyl A natural gas pipe replacement plan across its natural gas system. Later in 2012, after technical workshops held by the UTC to gather perspectives on pipeline replacement programs, including the need for expedited cost recovery, the UTC required all natural gas utilities operating in Washington to file applicable replacement plans with the Commission. We subsequently filed our protocol report with the UTC proposing to replace our Aldyl A natural gas pipe at a cost of approximately $10 million per year, indexed to inflation, across our three state jurisdictions over a 20-year period. We expect to receive cost recovery for these capital expenditures from the three jurisdictions over the subsequent future life of these assets.

Regulatory Issues

General As a 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 UTC, the IPUC, the Public Utility Commission of Oregon (OPUC), and the Public Service Commission of the State of Montana (Montana Commission). Approval of the issuance of securities is not required from the Montana Commission. We are also subject to the jurisdiction of the FERC for licensing of hydroelectric generation resources, and for electric transmission services and wholesale sales.

Our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are determined on a "cost of service" basis.

Rates are designed to provide an opportunity for us to recover allowable operating expenses and 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. Our operating expenses and rate base are allocated or directly assigned among five regulatory jurisdictions: electric in Washington and Idaho, and natural gas in Washington, Idaho and Oregon. In general, a request for new rates in Washington and Idaho is made on the basis of net investment as of a date, and operating expenses and revenues for a test year that ended prior to the date of the request , plus certain adjustments designed to reflect expected revenues, expenses and net investment during the period new retail rates will be in effect . Although the current ratemaking process in these states provides recovery of some future changes in net investment, operating costs and revenues, it does not reflect all changes in costs for the period in which new retail rates will be in place. This historically has resulted in a lag between the time we incur costs and the time when we start recovering the costs through subsequent changes in rates. Oregon currently allows a forecasted test year, which generally is more effective in providing timely recovery of costs.

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

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

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

Purchased Gas Adjustment (PGA) Under established regulatory practices in each 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 during the period the differences are incurred. During the subsequent period when regulators approve inclusion of the cost changes in rates, any amounts that were previously deferred are charged or credited to expense. We typically propose such PGAs at least once per year. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Avista Utilities – Regulatory Matters – Purchased Gas Adjustments” and “Note 23 of the Notes to Consolidated Financial Statements” for detailed information on natural gas cost deferrals and recovery mechanisms in Washington, Idaho and Oregon.

Federal Laws Related to Wholesale Competition

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

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

See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Competition” for further information.

Regional Transmission Organizations

Beginning with FERC Orders No. 888 and No. 2000 (issued in 2000) and continuing with subsequent rulemakings and policies (including the Variable Energy Resource Order No. 764 and the Transmission Planning and Cost Allocation Order No. 1000), the FERC has encouraged better coordination and operational consistency aimed to capture efficiencies that might otherwise be gained through the formation of a Regional Transmission Organization (RTO) such as an independent system operator (ISO). While it has not mandated RTO formation, the FERC has issued orders and made public policy statements indicating its support for the development and formation of independent organizations, including those intended to implement a number of regional transmission planning coordination requirements.

We have participated in discussions with transmission providers and other stakeholders in the Pacific Northwest for several years regarding the possible formation of an ISO in the region. ColumbiaGrid is a Washington nonprofit membership corporation with an independent slate of directors formed to improve the operational efficiency, reliability, and planned expansion of the transmission grid in the Pacific Northwest and we became a member of ColumbiaGrid in 2006 during its formation. ColumbiaGrid is not an ISO, but performs limited functions as set forth in specific agreements with ColumbiaGrid members and other stakeholders, and fills the role of coordinating Avista's regional planning as required in Order No. 1000 and any clarifying Orders. ColumbiaGrid and its members also work with other western organizations to address operational efficiencies, including WestConnect and the Northern Tier Transmissi on Group (NTTG). We became a registered Planning

Participant of the NTTG during 2011. We will continue to assess the benefits of entering into other functional agreements with ColumbiaGrid and/or participating in other forums to attain operational efficiencies and to meet FERC policy objectives.

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

Reliability Standards

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

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

AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

	Years Ended December 31,		
	2012	2011	2010
ELECTRIC OPERATIONS			
OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 315,137	$ 324,835	$ 296,627
Commercial	286,568	280,139	265,219
Industrial	119,589	122,560	114,792
Public street and highway lighting	7,240	6,941	6,702
Total retail	728,534	734,475	683,340
Wholesale	102,736	78,305	165,553
Sales of fuel	115,835	153,470	106,375
Other	21,067	21,937	19,015
Total electric operating revenues	$ 968,172	$ 988,187	$ 974,283
ENERGY SALES (Thousands of MWhs):			
Residential	3,608	3,728	3,618
Commercial	3,127	3,122	3,100
Industrial	2,100	2,147	2,099
Public street and highway lighting	26	26	26
Total retail	8,861	9,023	8,843
Wholesale	3,733	2,796	3,803
Total electric energy sales	12,594	11,819	12,646
ENERGY RESOURCES (Thousands of MWhs):			
Hydro generation (from Company facilities)	4,088	4,534	3,494
Thermal generation (from Company facilities)	2,864	2,447	3,748
Purchased power - hydro generation from long-term contracts with PUDs	1,022	1,047	685
Purchased power - thermal generation from long-term contracts with Lancaster plant	1,208	835	1,410
Purchased power - wholesale	4,056	3,553	3,905
Power exchanges	(10)	(24)	(15)
Total power resources	13,228	12,392	13,227
Energy losses and Company use	(634)	(573)	(581)
Total energy resources (net of losses)	12,594	11,819	12,646
NUMBER OF RETAIL CUSTOMERS (Average for Period):			
Residential	318,692	316,762	315,283
Commercial	39,869	39,618	39,489
Industrial	1,395	1,380	1,376
Public street and highway lighting	503	455	449
Total electric retail customers	360,459	358,215	356,597
RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (KWh)	11,323	11,769	11,476
Revenue per KWh (in cents)	8.73	8.71	8.20
Annual revenue per customer	$ 988.84	$ 1,025.48	$ 940.83
AVERAGE HOURLY LOAD (aMW)	1,075	1,096	1,075

AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

	Years Ended December 31,		
	2012	2011	2010
REQUIREMENTS AND RESOURCE AVAILABILITY at time of system peak (MW):			
Total requirements (winter):			
Retail native load	1,554	1,669	1,704
Wholesale obligations	637	712	803
Total requirements (winter)	2,191	2,381	2,507
Total resource availability (winter)	2,618	2,923	2,905
Total requirements (summer):			
Retail native load	1,579	1,535	1,556
Wholesale obligations	906	472	822
Total requirements (summer)	2,485	2,007	2,378
Total resource availability (summer)	3,060	2,370	2,662
COOLING DEGREE DAYS: (1)			
Spokane, WA			
Actual	535	426	380
30-year average	434	434	434
% of average	123%	98%	88%
HEATING DEGREE DAYS: (2)			
Spokane, WA			
Actual	6,256	6,861	6,320
30-year average	6,676	6,647	6,647
% of average	94%	103%	95%

(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).

(2) 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).

AVISTA UTILITIES NATURAL GAS OPERATING STATISTICS

	Years Ended December 31,		
	2012	2011	2010
NATURAL GAS OPERATIONS			
OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 196,719	$ 219,557	$ 193,169
Commercial	98,994	111,964	98,257
Interruptible	2,232	2,519	2,738
Industrial	3,635	4,180	3,756
Total retail	301,580	338,220	297,920
Wholesale	158,631	195,882	197,364
Transportation	7,032	6,709	6,470
Other	6,930	7,414	9,495
Total natural gas operating revenues	$ 474,173	$ 548,225	$ 511,249
THERMS DELIVERED (Thousands of Therms):			
Residential	189,152	207,202	188,546
Commercial	115,083	125,344	113,422
Interruptible	4,363	4,503	4,443
Industrial	5,073	5,654	5,312
Total retail	313,671	342,703	311,723
Wholesale	586,193	510,755	468,887
Transportation	154,704	152,515	142,093
Interdepartmental and Company use	381	440	393
Total therms delivered	1,054,949	1,006,413	923,096
SOURCES OF NATURAL GAS DELIVERED (Thousands of Therms):			
Purchases	919,684	877,290	787,836
Storage - injections	(105,904)	(109,782)	(86,750)
Storage - withdrawals	93,850	94,504	83,333
Natural gas for transportation	154,704	152,515	142,093
Distribution system losses	(7,385)	(8,114)	(3,416)
Total natural gas delivered	1,054,949	1,006,413	923,096
NUMBER OF RETAIL CUSTOMERS (Average for Period):			
Residential	286,522	284,504	282,721
Commercial	33,763	33,540	33,431
Interruptible	38	38	38
Industrial	263	255	254
Total natural gas retail customers	320,586	318,337	316,444
RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (therms)	660	728	667
Revenue per therm (in dollars)	$ 1.04	$ 1.06	$ 1.02
Annual revenue per customer	$ 686.57	$ 771.72	$ 683.25

AVISTA UTILITIES NATURAL GAS OPERATING STATISTICS

	Years Ended December 31,		
	2012	2011	2010
HEATING DEGREE DAYS: (1)			
Spokane, WA			
Actual	6,256	6,861	6,320
30-year average	6,676	6,647	6,647
% of average	94%	103%	95%
Medford, OR			
Actual	4,182	4,634	4,119
30-year average	4,422	4,402	4,402
% of average	95%	105%	94%

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

Ecova

Ecova provides sustainable utility expense management and energy management solutions to multi-site companies across North America. Ecova's invoice processing, auditing and payment services, coupled with energy procurement, comprehensive reporting and advanced analysis, provide the critical data clients need to help balance the financial, social and environmental aspects of doing business.

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

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

The following table presents key statistics for Ecova:

	2012	2011	2010
Expense management customers at year-end	740	645	534
Billed sites at year-end	697,076	496,842	360,596
Dollars of customer bills processed (in billions)	$ 19.4	$ 18.3	$ 17.3

Ecova's growth over the last several years in the key statistics listed above can be attributed to a combination of strategic acquisitions, new services and growth among existing customers, additional customers, and a high customer retention rate. On December 31, 2010, Ecova acquired The Loyalton Group, a Minneapolis-based energy management firm that provided energy procurement and price risk management solutions. In January 2011, Ecova acquired Building Knowledge Networks, a Seattle-based real-time building energy management services provider. In November 2011, Ecova acquired Prenova, an energy management company headquartered in Atlanta, Georgia. In January 2012, Ecova acquired LPB Energy Management (LPB), an energy management company headquartered in Dallas, Texas.

The noncontrolling interest of Ecova (which was 21.0 percent as of December 31, 2012) is primarily held by the previous owners of Cadence Network, a company acquired by Ecova in 2008.

Other Businesses

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

	2012	2011
Spokane Energy	$ 54,235	$ 66,317
Avista Energy	12,549	12,678
METALfx	11,273	11,919
Steam Plant and Courtyard Office Center	7,122	7,396
Other	10,459	13,835
Total	$ 95,638	$ 112,145

Spokane Energy is a special purpose limited liability company and all of its membership capital is owned by Avista Corp. Spokane Energy was formed in December 1998, to assume ownership of a fixed rate electric capacity contract between Avista Corp. and Portland General Electric Company. Of the total assets for Spokane Energy, the fixed rate electricity capacity contract represents $52.0 million and $62.5 million for 2012 and 2011, respectively and the likelihood of this asset being at risk of impairment is remote. In addition to the assets above, Spokane Energy also has nonrecourse long-term debt outstanding in the amount of $32.8 million and $46.5 million at December 31, 2012 and 2011, respectively, related to the acquisition of the fixed rate electric capacity contract. The final payment is due in January 2015 and Spokane Energy bears full recourse risk for the debt. See "Note 14 of the Notes to the Consolidated Financial Statements" for further discussion regarding this debt.

Avista Energy is a former electricity and natural gas marketing, trading and resource management business, which was a subsidiary of Avista Capital. This subsidiary has not been active since 2009; however, it continues to incur legal fees as it defends its actions related to several legal proceedings including the Federal Energy Regulatory Commission Inquiry, the

California Refund Proceeding, the Pacific Northwest Refund Proceeding, and the California Attorney General Complaint (the "Lockyer Complaint"). See "Note 21 of the Notes to the Consolidated Financial Statements" for further detail regarding these legal proceedings. The assets associated with Avista Energy are deferred tax assets related to its former operations.

Advanced Manufacturing and Development (AM&D) doing business as METALfx performs custom sheet metal fabrication of electronic enclosures, parts and systems for the computer, construction, telecom, renewable energy and medical industries.

Steam Plant and Courtyard Office Center consist of real estate investments (primarily commercial office buildings).

Our other investments and operations include:

- emerging technology venture capital funds, and
- residual ownership of a fuel cell business that was previously a subsidiary of the Company.

Over time as opportunities arise, we dispose of investments 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 we believe fit with our overall corporate strategy.

We are focused on discovering new ways to accelerate growth for Avista Corp. within and adjacent to our core utility business and are planning to spend $2.0 million to $3.0 million in 2013 exploring opportunities to develop new markets and ways for customers to use electricity and natural gas for commercial productivity and transportation. We may also make other targeted investments that will help us gain strategic insights to build new growth platforms.

Item 1A. Risk Factors

Risk Factors

The following factors could have a significant impact on our operations, results of operations, financial condition or cash flows. These factors could cause actual results or outcomes to differ materially from those discussed in our reports filed with the Securities and Exchange Commission (including this Annual Report on Form 10-K), and elsewhere. Please also see "Forward-Looking Statements" for additional factors which could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

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

Weather impacts are described in the following subtopics:

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

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

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

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

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

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

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

We have experienced higher costs for utility operations in each of the last several years. We have also made significant capital investments into utility plant assets. Our ability to recover these costs depends on the amount and timeliness of retail rate changes allowed by regulatory agencies. We expect to periodically file for rate increases with regulatory agencies to recover our costs and provide an opportunity to earn a reasonable rate of return for shareholders. If regulators grant substantially lower rate increases than our requests in the future or if deferred costs are disallowed, it could have a negative effect on our operating revenues, net income and cash flows. In addition, provisions to our approved settlement in the Washington general rate cases in 2012 and our proposed settlement to the Idaho general rate cases in 2013, do not prevent us from filing general rate cases in these two jurisdictions in 2014; however, new rates from these general rate case filings would not take effect prior to January 1, 2015.

Energy commodity price changes affect our cash flows and results of operations.

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

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

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

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

Cash flow deferrals related to energy commodities can be significant. We are permitted to collect from customers only amounts approved by regulatory commissions. However, our costs to provide energy service can be much higher or lower than the amounts currently billed to customers. We are permitted to defer most of this difference for review by the regulatory commissions who have discretion as to the extent and timing of future recovery or refund to customers.

Power and natural gas costs higher than those recovered in retail rates reduce cash flows. Amounts that are not allowed for deferral or which are not approved to become part of customer rates affect our results of operations.

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

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

Our energy resource risk management processes can cause volatility in our cash flows and results of operations.

We engage in active hedging and resource optimization practices but 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 require additional transactions or dispatch decisions that impact cash flows.

The hedges we enter into are reviewed for prudence by the various regulators and any deferred costs (including those as a result of our hedging transactions) are subject to review for prudence and potential disallowance by regulators.

We rely on regular access to financial markets but we cannot assure favorable or reasonable financing terms will be available when we need them.

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

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

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

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

We need adequate levels of credit with financial institutions for short-term liquidity. We have a $400.0 million committed line of credit that is scheduled to expire in February 2017. There is no assurance that we will have access to credit beyond the expiration date. The committed line of credit agreement contains customary covenants and default provisions. In the event of default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock.

In July 2012, Ecova entered into a $125.0 million committed line of credit agreement with various financial institutions that replaced its $60.0 million committed line of credit agreement and has an expiration date of July 2017. There is no assurance that we will have access to credit beyond the expiration date. The committed line of credit agreement contains customary covenants and default provisions, and based on certain covenant conditions contained in the credit agreement, at December 31, 2012, Ecova could borrow an additional $5.6 million and still be compliant with the covenants. The covenant restrictions are calculated on a rolling twelve month basis, so this additional borrowing capacity could increase or decrease or Ecova could be required to pay down the outstanding debt as future results change. See further discussion of the specific covenants in "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations - Ecova Credit Agreement." In the event of default, it would be difficult for Ecova to obtain financing on reasonable terms to pay creditors or fund operations.

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

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

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

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

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

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

Ecova, may be unable to attain the level or timeliness of growth we expect.

Ecova's operations involve several recent acquisitions and may include other acquisitions as opportunities warrant. There are various uncertainties involved with assimilating acquired operations, achieving revenue growth and operating synergies in acquired operations. Ecova's organic growth and its ability to manage costs with the dynamics of growth and emerging business processes make it more difficult to accurately forecast cash flows and results of operations. As a result, earnings may be more volatile and cash flows may be irregular in this business segment.

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

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

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

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

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

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

There have been numerous recent changes in legislation, related administrative rulemaking, and Executive Orders, including periodic audits of compliance with such rules, which may adversely affect our operational and financial performance.

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

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

Actions or limitations to address concerns over long-term global climate changes may affect our operations and financial performance.

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

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

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

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

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

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	88.0
Little Falls (Spokane)	4	32.0	35.6
Nine Mile (Spokane) (5)	4	26.4	22.4
Upper Falls (Spokane)	1	10.0	10.2
Monroe Street (Spokane)	1	14.8	15.0
Idaho:			
Cabinet Gorge (Clark Fork) (3)	4	265.0	273.0
Post Falls (Spokane)	6	14.8	15.4
Montana:			
Noxon Rapids (Clark Fork)	5	480.6	562.4
Total Hydroelectric		913.6	1,022.0
Thermal Generating Stations			
Washington:			
Kettle Falls GS	1	50.7	53.5
Kettle Falls CT	1	7.2	6.9
Northeast CT	2	61.8	64.8
Boulder Park	6	24.6	24.0
Idaho:			
Rathdrum CT	2	166.5	166.5
Montana:			
Colstrip Units 3 and 4 (4)	2	233.4	222.0
Oregon:			
Coyote Springs 2	1	287.0	284.4
Total Thermal		831.2	822.1
Total Generation Properties		1,744.8	1,844.1

(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, 2012.

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

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

(5) There are currently four units at the Nine Mile plant; however, the present capability is limited due to a mechanical failure of Units 1 and 2. A project is underway to replace these units and restore capability. The nameplate rating of the two remaining units is 18 MW.

Electric Distribution and Transmission Plant

We own and operate approximately 18,600 miles of primary and secondary electric distribution lines providing service to retail customers. We have an electric transmission system of 685 miles of 230 kV line and 1,534 miles of 115 kV line. We also own an 11 percent interest in approximately 500 miles of a 500 kV line between Colstrip, Montana and Townsend, Montana. Our transmission and distribution systems also include numerous substations with transformers, switches, monitoring and metering devices, and other equipment.

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

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

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

Natural Gas Plant

We have natural gas distribution mains of approximately 3,400 miles in Washington, 1,970 miles in Idaho and 2,300 miles in Oregon. We have natural gas transmission mains of approximately 75 miles in Washington and 40 miles in Oregon. Our natural gas system includes numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment.

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

Item 3. Legal Proceedings

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

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is currently listed on the New York Stock Exchange under the ticker symbol "AVA". As of January 31, 2013, there were 10,083 registered shareholders of our common stock.

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

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

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

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

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

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

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

	Three Months Ended			
	March 31	June 30	September 30	December 31
2012				
Dividends paid per common share	$ 0.29	$ 0.29	$ 0.29	$ 0.29
Trading price range per common share:				
High	$ 26.18	$ 27.07	$ 28.05	$ 26.77
Low	$ 24.48	$ 24.95	$ 25.07	$ 22.78
2011				
Dividends paid per common share	$ 0.275	$ 0.275	$ 0.275	$ 0.275
Trading price range per common share:				
High	$ 23.69	$ 25.83	$ 26.53	$ 26.35
Low	$ 21.78	$ 22.81	$ 21.13	$ 23.14

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

(in thousands, except per share data and ratios)	Years Ended December 31,				
	2012	2011	2010	2009	2008
Operating Revenues:					
Avista Utilities	$ 1,354,185	$ 1,443,322	$ 1,419,646	$ 1,395,201	$ 1,572,664
Ecova	155,664	137,848	102,035	77,275	59,085
Other	38,953	40,410	61,067	40,089	45,014
Intersegment eliminations	(1,800)	(1,800)	(24,008)	—	—
Total	$ 1,547,002	$ 1,619,780	$ 1,558,740	$ 1,512,565	$ 1,676,763
Income (Loss) from Operations (pre-tax):					
Avista Utilities (3)	$ 188,778	$ 202,373	$ 198,200	$ 188,511	$ 170,067
Ecova	2,972	20,917	15,865	11,603	11,297
Other (3)	(1,680)	4,714	5,669	(7,103)	(1,454)
Total	$ 190,070	$ 228,004	$ 219,734	$ 193,011	$ 179,910
Net income	$ 78,800	$ 103,539	$ 94,948	$ 88,648	$ 74,757
Net income attributable to noncontrolling interests	$ (590)	$ (3,315)	$ (2,523)	$ (1,577)	$ (1,137)
Net Income (Loss) Attributable to Avista Corporation shareholders:					
Avista Utilities	$ 81,704	$ 90,902	$ 86,681	$ 86,744	$ 70,032
Ecova	1,825	9,671	7,433	5,329	6,090
Other	(5,319)	(349)	(1,689)	(5,002)	(2,502)
Total	$ 78,210	$ 100,224	$ 92,425	$ 87,071	$ 73,620
Average common shares outstanding, basic	59,028	57,872	55,595	54,694	53,637
Average common shares outstanding, diluted	59,201	58,092	55,824	54,942	54,028
Common shares outstanding at year-end	59,813	58,423	57,120	54,837	54,488
Earnings per Common Share Attributable to Avista Corporation shareholders:					
Diluted	$ 1.32	$ 1.72	$ 1.65	$ 1.58	$ 1.36
Basic	$ 1.32	$ 1.73	$ 1.66	$ 1.59	$ 1.37
Dividends paid per common share	$ 1.16	$ 1.10	$ 1.00	$ 0.81	$ 0.69
Book value per common share at year-end	$ 21.06	$ 20.30	$ 19.71	$ 19.17	$ 18.30
Total Assets at Year-End:					
Avista Utilities	$ 3,894,821	$ 3,809,446	$ 3,589,235	$ 3,400,384	$ 3,434,844
Ecova	322,720	292,940	221,086	143,060	125,911
Other	95,638	112,145	129,774	63,515	69,992
Total	$ 4,313,179	$ 4,214,531	$ 3,940,095	$ 3,606,959	$ 3,630,747
Long-Term Debt (including current portion)	$ 1,228,739	$ 1,177,300	$ 1,101,857	$ 1,071,338	$ 826,465
Nonrecourse Long-Term Debt of Spokane					
Energy (including current portion) (1)	$ 32,803	$ 46,471	$ 58,934	$ —	$ —
Long-Term Debt to Affiliated Trusts	$ 51,547	$ 51,547	$ 51,547	$ 51,547	$ 113,403
Total Avista Corporation Stockholders' Equity	$ 1,259,477	$ 1,185,701	$ 1,125,784	$ 1,051,287	$ 996,883
Ratio of Earnings to Fixed Charges (2)	2.47	3.06	2.86	2.95	2.43

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

(2) See Exhibit 12 for computations.

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

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Business Segments

We have two reportable business segments as follows:

- **Avista Utilities** – an operating division of Avista Corp. that comprises our regulated utility operations. Avista Utilities generates, transmits and distributes electricity and distributes natural gas. The utility also engages in wholesale purchases and sales of electricity and natural gas.
- **Ecova** – an indirect subsidiary of Avista Corp. (79.0 percent owned as of December 31, 2012) provides energy efficiency and cost management programs and services for multi-site customers and utilities throughout North America. Ecova's service lines include expense management services for utility and telecom needs as well as strategic energy management and efficiency services that include procurement, conservation, performance reporting, financial planning, facility optimization and continuous monitoring, and energy efficiency program management for commercial enterprises and utilities.

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

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

	2012	2011	2010
Avista Utilities	$ 81,704	$ 90,902	$ 86,681
Ecova	1,825	9,671	7,433
Other	(5,319)	(349)	(1,689)
Net income attributable to Avista Corporation shareholders	$ 78,210	$ 100,224	$ 92,425

Executive Level Summary

Overall

Net income attributable to Avista Corporation shareholders was $78.2 million for 2012, a decrease from $100.2 million for 2011. This was due to a decrease in earnings at each of our businesses. Earnings at Avista Utilities decreased primarily due to reduced retail loads during the first and fourth quarters of the year (as a result of warmer weather) and due in part to lower usage at certain industrial customers, due to temporary operational challenges. In addition, there were increases in other operating expenses (including costs under a voluntary severance incentive program), and depreciation and amortization, partially offset by the implementation of general rate increases. Net income at Ecova decreased as revenue growth for the expense and data management services and energy management services at Ecova was not as high as expected and did not offset increased operating costs. In addition, Ecova's earnings were reduced by increased costs associated with completing and integrating the acquisitions of Prenova and LPB and an increase in depreciation and amortization. Net income at other subsidiaries decreased due losses on investments, inclusive of an impairment loss recognized during the third quarter, increased costs associated with strategic consulting and other corporate costs, and increased litigation costs related to the previous operations of Avista Energy. These losses were partially offset by positive earnings at METALfx. These results, including a quantification of their respective impacts, are discussed in detail below.

Avista Utilities

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

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

Based on our forecasts for our utility operations for 2013 through 2016, we expect annual electric customer growth to average 0.7 percent to 1.3 percent per year and annual natural gas customer growth to average 0.7 percent to 1.8 percent within our service area. We anticipate retail electric load growth to average between 0.7 percent and 1.0 percent and natural gas load growth to average between 0.7 percent and 1.4 percent. We anticipate customer and load growth at the lower end of the range in 2013 and a modest recovery as the economy strengthens during the four-year period. While the number of electric and natural gas customers is growing, the average annual usage by each residential customer has not changed significantly. For further discussion regarding utility customer growth, load growth, and the general economic conditions in our service territory, see "Economic Conditions and Utility Load Growth".

In our utility operations, we regularly review the need for rate changes in each jurisdiction to improve the recovery of costs and capital investments in our generation, transmission and distribution systems. General rate increases went into effect in Idaho on October 1, 2011, in Washington on January 1, 2012, and in Oregon effective March 15, 2011, June 1, 2011 and June 1, 2012. On October 11, 2012 we filed electric and natural gas general rate increase requests in Idaho, which are currently the subject of a settlement that is before the IPUC for approval (see discussion below under "Idaho General Rate Cases"). In December 2012, the UTC approved a settlement agreement in our Washington general rate cases, which were originally filed on April 2, 2012, that provides for electric and natural gas rate increases effective January 1, 2013 and January 1, 2014.

We are making significant capital investments in generation, transmission and distribution systems to preserve and enhance service reliability for our customers and replace aging infrastructure. Utility capital expenditures were $271.2 million for 2012. We expect utility capital expenditures to be about $260 million for each of 2013 and 2014. These estimates of capital expenditures are subject to continuing review and adjustment (see discussion under “Avista Utilities Capital Expenditures”).

On October 22, 2012, we announced a voluntary severance incentive program to reduce our total utility workforce and achieve necessary long-term, sustainable, Company-wide savings, in addition to other cost saving measures.

Based on the response to the program by interested employees and the approvals by Company management the program resulted in the termination of 55, or approximately 6 percent, of the eligible 919 non-union employees, and the total severance costs under the program were $7.3 million (pre-tax). The long-term operating and maintenance cost savings under the program are expected to exceed the severance costs of the program and the expected payback period for the severance costs will be approximately 1.4 years.

All terminations under the voluntary severance incentive program were completed by December 31, 2012. The cost of the program was recognized as expense during the fourth quarter of 2012 and severance pay was distributed in a single lump sum cash payment to each participant during January 2013.

An agreement with one of our largest electric customers, which consumes approximately 100 aMWs per year, is expiring on June 30, 2013. We are currently renegotiating a new agreement with this customer that is expected to become effective July 1, 2013. The new agreement will be subject to approval from the IPUC once it is finalized. We would expect to receive regulatory recovery of any changes in costs or revenues related to the agreement.

Ecova

On November 30, 2011, Ecova acquired Prenova, an Atlanta-based energy management company. The cash paid for the acquisition of Prenova of $35.7 million was funded primarily through borrowings under Ecova's committed credit agreement.

On January 31, 2012, Ecova acquired LPB, a Dallas-based energy management company. The cash paid for the acquisition of LPB of $50.6 million was funded by Ecova through $25.0 million of borrowings under its committed credit agreement, a $20.0 million equity infusion from existing shareholders (including Avista Capital and the other owners of Ecova), and available cash.

While these acquisitions have grown the overall cost structure for Ecova for 2012, they have also increased both operating revenues and Ecova's market share and will allow Ecova to offer its clients a broader range of services which should lead to potential future earnings growth as the acquisitions are integrated with Ecova's operations.

The acquisition of Cadence Network in July 2008 was funded by issuing additional Ecova common stock. Under the transaction agreement, the previous owners of Cadence Network had a right to have their shares of Ecova common stock redeemed by Ecova during July 2011 or July 2012 if their investment in Ecova was not liquidated through either an initial public offering or sale of the business to a third party. These redemption rights were not exercised and expired effective July 31, 2012 and were reclassified to permanent equity, which resulted in a decrease of $41.6 million in redeemable noncontrolling interests from December 31, 2011.

The value of the remaining redeemable noncontrolling interests in Ecova associated with redeemable stock options and other outstanding redeemable stock was $4.9 million at December 31, 2012, a decrease from $12.9 million at December 31, 2011. Options are valued at their maximum redemption amount which is equal to their intrinsic value (fair value less exercise price). During 2012, the estimated fair value of Ecova common stock decreased such that it is closer to the exercise price of the options which reduced the overall value of the redeemable noncontrolling interests down to their current value.

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

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

Liquidity and Capital Resources

We have a committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2017. As of December 31, 2012, there were $52.0 million of cash borrowings and $35.9 million in letters of credit outstanding leaving $312.1 million of available liquidity under this line of credit.

In July 2012, Ecova entered into a five-year $125.0 million committed line of credit agreement with various financial institutions that replaced its $60.0 million committed line of credit agreement. As of December 31, 2012, Ecova had $54.0 million of borrowings outstanding under its committed line of credit agreement. Based on certain covenant conditions contained in the credit agreement, at December 31, 2012, Ecova could borrow an additional $5.6 million and still be compliant with the covenants. The covenant restrictions are calculated on a rolling twelve month basis, so this additional borrowing capacity could increase or decrease or Ecova could be required to pay down the outstanding debt as future results change. We expect Ecova's earnings to increase in the future, so we expect the excess borrowing capacity to increase as well. See further discussion of the specific covenants below under "Ecova Credit Agreement".

In November 2012, we issued $80.0 million of 4.23 percent First Mortgage Bonds due in 2047 as an obligation of Avista Corp. Net total proceeds from the sale of the new bonds were used to repay a portion of the borrowings outstanding under our $400.0 million committed line of credit and for general corporate purposes. There are $50.0 million in First Mortgage Bonds maturing in 2013 and we expect to issue up to $100 million of long-term debt during the second half of 2013.

In May 2012, we cash settled interest rate swap contracts (notional amount of $75.0 million) and paid a total of $18.5 million. The interest rate swap contracts were settled in connection with the pricing of $80.0 million of First Mortgage Bonds as described above. Upon settlement of the interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the life of the forecasted interest payments.

In August 2012, we entered into two sales agency agreements under which we may issue up to 2.7 million shares of our common stock from time to time. In 2012, we sold 0.9 million shares and received net proceeds of $23.4 million (net of issuance costs). As of December 31, 2012, we had 1.8 million shares available to be issued under these agreements.

In 2012 we received net proceeds of $29.1 million (net of issuance costs) by issuing common stock, including $23.4 million under our sales agency agreements. During 2013, we expect to issue up to $50 million of common stock in order to maintain our capital structure at an appropriate level for our business. After considering the issuances of long-term debt and common stock during 2013, we expect net cash flows from operating activities, together with cash available under our $400.0 million committed line of credit agreement, to provide adequate resources to fund capital expenditures, dividends, and other contractual commitments.

Avista Utilities – Regulatory Matters

General Rate Cases

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

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

With regards to the timing and plans for future filings, the assessment of our need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include, but are not limited to, in-service dates of major capital investments and the timing of changes in major revenue and expense items. We filed general rate cases in Washington in May 2011 (which were settled with new rates effective January 1, 2012) and in Idaho in July 2011 (which were settled with new rates effective October 1, 2011). We filed general rate cases in Washington in April 2012 (which were settled with new rates effective January 1, 2013 and January 1, 2014) and Idaho in October 2012 (which are the subject of a settlement that is before the IPUC (see discussion below under "Idaho General Rate Cases")).

Washington General Rate Cases

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

In December 2011, the UTC approved a settlement agreement in our electric and natural gas general rate cases filed in May 2011. As agreed to in the settlement agreement, base electric rates for our Washington customers increased by an average of 4.6 percent, which was designed to increase annual revenues by $20.0 million. Base natural gas rates for our Washington customers increased by an average of 2.4 percent, which was designed to increase annual revenues by $3.75 million. The new electric and natural gas rates became effective on January 1, 2012.

The settlement agreement provided for the deferral of certain generation plant maintenance costs. In order to address the variability in year-to-year maintenance costs, beginning in 2011, we deferred certain changes in maintenance costs related to our Coyote Springs 2 natural gas-fired generation plant and our 15 percent ownership interest in Units 3&4 of the Colstrip generation plant. These maintenance costs may be much higher in certain years because certain significant maintenance procedures are less frequent than annual and, therefore, may not be properly represented in test year expenses used in our filed rate requests. For 2011 and 2012 the Company compared actual, non-fuel, maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of baseline maintenance expenses used to establish base retail rates, and deferred the difference. This deferral occurred annually, with no carrying charge, with deferred costs being amortized over a four-year period, beginning in the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases would be the actual maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. Total net deferred costs under this mechanism in Washington were a regulatory asset of $4.0 million as of December 31, 2012 compared to a regulatory liability of $0.5 million as of December 31, 2011. As part of the settlement agreement in October 2012 to our latest general rate case discussed in further detail below, the parties have agreed that the maintenance cost deferral mechanism on these generation plants will terminate on December 31, 2012, with the four-year amortization of the 2011 and 2012 deferrals to conclude in 2015 and 2016, respectively.

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

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

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

In addition, in its Order, the UTC found that much of the approved base rate increases is justified by the planned capital expenditures necessary to upgrade and maintain our utility facilities. If these capital projects are not completed to a level that was contemplated in the original settlement agreement, this could result in base rates which are considered too high by the

UTC. As a result, we must file capital expenditure progress reports with the UTC on a periodic basis so that the UTC can monitor the capital expenditures and ensure they are in line with those contemplated in the settlement agreement. We expect total utility capital expenditures among all jurisdictions to be approximately $260 million for each of 2013 and 2014.

The settlement agreement provides for an authorized return on equity of 9.8 percent and an equity ratio of 47 percent, resulting in an overall return on rate base of 7.64 percent.

Idaho General Rate Cases

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

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

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

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

The settlement agreement also provides for the deferral of certain generation plant operation and maintenance costs. In order to address the variability in year-to-year operation and maintenance costs, beginning in 2011, we are deferring certain changes in operation and maintenance costs related to the Coyote Springs 2 natural gas-fired generation plant and our 15 percent ownership interest in Units 3&4 of the Colstrip generation plant. We compare actual, non-fuel, operation and maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of expenses authorized for recovery in base rates in the applicable deferral year, and defer the difference from that currently authorized. The deferral occurs annually, with no carrying charge, with deferred costs being amortized over a three-year period, beginning in the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases will be the actual operation and maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. Total net deferred costs under this mechanism in Idaho were regulatory assets of $2.3 million as of December 31, 2012 and $0.1 million as of December 31, 2011.

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

On February 6, 2013, Avista Corp. and certain other parties filed a settlement agreement with the IPUC with respect to our electric and natural gas general rate cases. Parties to the settlement agreement include the staff of the IPUC, Clearwater Paper Corporation, Idaho Forest Group, LLC, the Idaho Conservation League, and the Company. Community Action Partnership Association of Idaho (CAPAI), a low-income customer advocacy group, and the Snake River Alliance did not join in the settlement agreement. However, on February 20, 2013 the Snake River Alliance provided a letter to the IPUC supporting the settlement agreement. This settlement agreement is subject to approval by the IPUC and would conclude the proceedings related the general rate requests filed by the Company on October 11, 2012. New rates would be implemented in two phases: April 1, 2013 and October 1, 2013.

The settlement agreement proposes that, effective April 1, 2013, we would be authorized to implement a base rate increase for our Idaho natural gas customers of 4.9 percent (designed to increase annual revenues by $3.1 million). There would be no change in base electric rates on April 1, 2013. However, the settlement agreement would provide for the recovery of the costs of the Palouse Wind Project through the Power Cost Adjustment mechanism beginning April 1, 2013.

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

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

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

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

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

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

Oregon General Rate Cases

In March 2011, the OPUC approved an all-party settlement stipulation in our general rate case that was filed in September 2010. The settlement provided for an overall rate increase of 3.1 percent for our Oregon customers, designed to increase annual revenues by $3.0 million. Part of the rate increase became effective March 15, 2011, with the remaining increase effective June 1, 2011. An additional rate adjustment designed to increase revenues by $0.6 million became effective on June 1, 2012 to recover capital costs associated with certain reinforcement and replacement projects, having demonstrated that such projects were complete by November 1, 2011, and the costs incurred were prudent. In addition, rates increased by an additional $0.5 million, from June 1, 2012 through May 31, 2013, to recover the November 2011 through May 2012 deferred revenue requirement.

On January 1, 2013, we purchased the Klamath Falls Lateral (Lateral), a 15-mile, 6-inch natural gas transmission pipeline from Williams Northwest Pipeline (Williams). The Klamath Falls Lateral interconnects with another interstate pipeline, Gas Transmission Northwest, to transport natural gas to serve our customers in Klamath Falls, Oregon. The purchase price was approximately $2.3 million and will save our Oregon customers approximately $1.4 million annually as we will be able to reduce our contracted natural gas transportation requirements from Williams. In Order No. 12-429, the OPUC approved our request to recover from customers the revenue requirement associated with the purchase of the Lateral, which is approximately $0.5 million annually. This approval will provide a return of and a return on our investment in the lateral. While the OPUC approved the recovery of the revenue requirement, it will not determine whether the purchase of the Lateral was prudent until our next Oregon general rate case.

Proposed Electric Decoupling–Washington

In the September 2011 Washington general rate case settlement (which was approved by the UTC in December 2011), one party, the Northwest Energy Coalition (NWEC), did not sign the agreement and continued to pursue an electric decoupling mechanism for us through a separate procedural schedule. On May 14, 2012, the UTC consolidated this issue into our April 2012 Washington general rate case. As a part of the Settlement filed on October 19, 2012, related to our April 2012 Washington general rate case, we agreed that we would not support adoption of decoupling in this case, nor seek to implement a decoupling mechanism prior to our next general rate case. In the UTC's Order approving the settlement agreement, however, the UTC did not support this provision related to decoupling in the settlement agreement.

Bonneville Power Administration Reimbursement and Reardan Wind Generation Project

On January 28, 2013, we filed with the UTC a Petition for an order that authorizes certain ratemaking treatment related to two issues: The first issue relates to transmission revenues associated with a settlement between Avista Corp. and the Bonneville

Power Administration ("Bonneville"), whereby Bonneville will reimburse the Company $11.7 million for its past use of our transmission system. The second issue relates to approximately $4 million of costs we incurred over the past several years for the development of a wind generation project site near Reardan, Washington. We propose to allocate $7.6 million, representing Washington's share of the Bonneville Settlement, as follows: $4.6 million would be allocated to benefit customers, and $3.0 million would be retained by the Company. With regard to the recovery of costs for Reardan, we propose to use $2.6 million of the Washington customers' share of the Bonneville settlement proceeds to fully offset the Washington share of Reardan costs, and the remaining $2.0 million would be credited to the ERM balancing account for the benefit of customers. In Idaho, under the terms of the proposed rate case settlement, Idaho's share of the BPA settlement would be credited back to customers over 15 months, beginning October 2013, and we would amortize Idaho's share of Reardan costs over a two-year period, beginning April 2013.

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to our customers with no change in gross margin (operating revenues less resource costs) or net income. Effective October 1, 2011, natural gas rates increased 1.0 percent in Idaho. Effective November 1, 2011, natural gas rates increased 1.0 percent in Washington, while decreasing 0.2 percent in Oregon. In Oregon, we absorb (gain or loss) 10 percent of the difference between actual and projected gas costs for supply that is not hedged. Total net deferred natural gas costs were a liability of $12.1 million as of December 31, 2011.

Effective March 1, 2012, natural gas rates decreased 6.4 percent in Washington and 6.0 percent in Idaho. Effective October 1, 2012, natural gas rates decreased 3.1 percent in Idaho. Effective November 1, 2012, natural gas rates decreased 4.4 percent in Washington and 7.5 percent in Oregon. Total net deferred natural gas costs were a liability of $6.9 million as of December 31, 2012.

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

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

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used to track certain differences between actual power supply costs, net of the margin on wholesale sales and sales of fuel, and the amount included in base retail rates for our Washington customers. In the 2010 Washington general rate case settlement, the parties agreed that there would be no deferrals under the ERM in 2010. Deferrals under the ERM resumed in 2011. Total net deferred power costs under the ERM were a liability of $22.2 million as of December 31, 2012 compared to $12.9 million as of December 31, 2011, and these balances represent the customer portion of the deferred power costs. As part of the approved Washington general rate case settlement in December 2012, during 2013 a one-year credit of $4.4 million will be returned to electric customers from the existing ERM deferral balance to reduce the net average electric rate increase impact to customers in 2013. Additionally, during 2014 a one-year credit up to $9.0 million will be returned to electric customers from the then-existing ERM deferral balance, if such funds are available, so the net average electric rate increase impact to customers effective January 1, 2014 would also be reduced. The credits to customers from the ERM balances would not impact our net income.

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

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

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

The following is a summary of the ERM:

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

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

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

We have a PCA mechanism in Idaho that allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. The October 1 rate adjustments recover or rebate power supply costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a liability of $5.1 million as of December 31, 2012 compared to $0.7 million as of December 31, 2011.

Natural Gas Safety Regulations

On February 3, 2012, President Obama signed into law the “Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011” mandating new regulations be created to address public safety concerns. Regulations include validation of pipeline records for transmission pipelines, evaluation of transmission pipelines for automatic shut-off valves, consideration of increased “high consequence area” boundaries for transmission pipelines, increased installation of excess flow valves on gas service piping, as well as increased scrutiny on existing emergency preparedness plans, quality assurance plans and damage prevention programs, and broader federal oversight including broader use of fines and penalties to pipeline operators. The U.S. Department of Transportation has already proposed rules that address many areas of the new Act and we have already complied with many of the requirements of this legislation. We are still evaluating the Act and waiting for further rules and clarifications surrounding certain portions of this Act; however, we expect that any additional compliance required would not have a significant impact on our operations.

Results of Operations

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

2012 compared to 2011

Utility revenues decreased $89.1 million, after elimination of intracompany revenues of $88.2 million for 2012 and $93.1 million for 2011. Including intracompany revenues, electric revenues decreased $20.0 million and natural gas revenues decreased $74.1 million. Retail electric revenues decreased $5.9 million due to a decrease in volumes sold which was primarily the result of warmer weather during the heating season and lower usage at certain industrial customers, due to temporary operational challenges at these customers. This was mostly offset during the third quarter due to warmer weather (and increased cooling loads), which increased electric use per customer and also general rate increases. Retail natural gas revenues decreased $36.6 million due to a decrease in volumes caused by warmer weather.

Ecova revenues increased $17.8 million to $155.7 million primarily as a result of Ecova's acquisitions of Prenova effective November 30, 2011 and LPB effective January 31, 2012.

Utility resource costs decreased $96.9 million, after elimination of intracompany resource costs of $88.2 million for 2012 and $93.1 million for 2011. Including intracompany resource costs, electric resource costs decreased $32.9 million and natural gas resource costs decreased $68.9 million. The decrease in electric resource costs was primarily due to a decrease in other fuel costs (represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation as part of the resource optimization process) and the amortization of deferred power supply costs, partially offset by an increase in fuel costs (due to higher thermal generation) and power purchased. The decrease in natural gas resource costs was primarily due to a decrease in natural gas prices, partially offset by an increase in volumes.

Utility other operating expenses increased $14.9 million primarily due to labor (including $7.3 million of costs under the voluntary severance incentive plan), increased pensions and other postretirement benefits, and electric distribution costs, partially offset by decreased electric maintenance costs (which included the regulatory deferral of $6.7 million of maintenance costs) and outside service costs.

Utility depreciation and amortization increased $6.5 million driven by additions to utility plant.

Ecova other operating expenses increased $29.4 million primarily reflecting increased costs necessary for business growth and the acquisitions of Prenova and LPB, including transaction and integration costs of $2.6 million.

Ecova depreciation and amortization increased $6.3 million primarily due to the amortization of intangibles recorded in connection with Ecova's acquisitions of Prenova and LPB.

Other non-utility operating expenses increased $4.9 million primarily due to increased outside service expense of $1.2 million and increased consulting services and other corporate costs that can't be charged to utility customers of $2.5 million.

Interest expense increased $3.0 million primarily due to the issuance of long-term debt in December 2011 that increased the balance of long-term debt outstanding.

Other income-net increased $1.6 million primarily due to an increase in equity method earnings of $1.8 million from Ecova's investment in the SEEL variable interest entity. In prior years, this entity was consolidated and the operating revenues and expenses were included in the consolidated results of the Company. Additionally, equity-related AFUDC increased $1.8 million. These increases in other income were offset by an increase in losses on investments, including $2.4 million for the impairment of our investment in a fuel cell business and the write-off of our investment in a solar energy company.

Income taxes decreased $15.4 million and our effective tax rate was 34.4 percent for 2012 compared to 35.4 percent for 2011. The decrease in expense was primarily due to a decrease in income before income taxes.

2011 compared to 2010

Utility revenues increased $23.7 million, after elimination of intracompany revenues of $93.1 million in 2011 and $65.9 million in 2010. Including intracompany revenues, electric revenues increased $13.9 million and natural gas revenues increased $37.0 million. Retail electric revenues increased $51.1 million due to general rate increases and an increase in volumes sold caused by colder weather during the first three months of 2011 compared to 2010. Retail natural gas revenues increased $40.3 million due to an increase in volumes caused by colder weather and prices from rate increases.

Ecova revenues increased $35.8 million to $137.8 million primarily due to growth in expense management and energy management services, as well as the acquisition of Loyalton effective December 31, 2010.

Revenues from our other businesses increased $1.6 million (excluding intercompany revenues) primarily due to increased sales at METALfx.

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

Utility other operating expenses increased $9.5 million primarily due to increased maintenance expenses (including planned major maintenance at Colstrip), pensions and other postretirement benefits, and labor.

Utility depreciation and amortization increased $5.1 million driven by additions to utility plant.

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

Ecova other operating expenses increased $29.6 million reflecting increased costs necessary for business growth and the acquisition of Loyalton.

Interest expense decreased $1.9 million primarily due to refinancing transactions completed in December 2010 that lowered our effective rate on long-term debt. This was partially offset by higher interest rates on short-term borrowings.

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

Other income-net decreased $0.9 million primarily due to a decrease in losses on investments (including a $2.2 million impairment of our investment in a fuel cell business recorded in 2010), partially offset by a decrease in equity-related AFUDC.

Income taxes increased $5.5 million and our effective tax rate was 35.4 percent for 2011 compared to 35.0 percent for 2010. This increase in expense was primarily due to an increase in income before income taxes. Adjustments associated with reconciling the 2009 federal income tax return to the amount included in the financial statements for 2009 and prior year income tax return amendments decreased income tax expense by $1.7 million for 2010.

Avista Utilities

Non-GAAP Financial Measures

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

2012 compared to 2011

Net income for Avista Utilities was $81.7 million for 2012, a decrease from $90.9 million for 2011. Avista Utilities’ income from operations was $188.8 million for 2012 compared to $202.4 million for 2011. The decrease in net income and income from operations was primarily due to reduced retail loads during the first and fourth quarters of the year and an increase in other operating expenses (including costs for the voluntary severance incentive program), and depreciation and amortization, partially offset by the implementation of general rate increases. The decrease in net income from Avista Utilities was also due to an increase in interest expense.

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

	Electric		Natural Gas		Intracompany		Total	
	2012	2011	2012	2011	2012	2011	2012	2011
Operating revenues	$ 968,172	$ 988,187	$ 474,173	$ 548,225	$ (88,160)	$ (93,090)	$ 1,354,185	$ 1,443,322
Resource costs	451,434	484,359	329,853	398,779	(88,160)	(93,090)	693,127	790,048
Gross margin	$ 516,738	$ 503,828	$ 144,320	$ 149,446	$ —	$ —	$ 661,058	$ 653,274

Avista Utilities’ operating revenues decreased $89.1 million and resource costs decreased $96.9 million, which resulted in an increase of $7.8 million in gross margin. The gross margin on electric sales increased $12.9 million and the gross margin on natural gas sales decreased $5.1 million. The increase in electric gross margin was primarily due to general rate increases. This was partially offset by warmer weather during the heating season (primarily the first and fourth quarters) that reduced retail loads. In addition, electric gross margin growth was limited in part by lower usage at certain industrial customers due to temporary operational challenges. Natural gas gross margin decreased primarily due to warmer weather throughout the year that reduced retail heating loads, partially offset by general rate increases. For 2012, we recognized a pre-tax benefit of $6.0 million under the ERM in Washington compared to $6.4 million for 2011.

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

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

	Electric Operating Revenues		Electric Energy MWh sales	
	2012	2011	2012	2011
Residential	$ 315,137	$ 324,835	3,608	3,728
Commercial	286,568	280,139	3,127	3,122
Industrial	119,589	122,560	2,100	2,147
Public street and highway lighting	7,240	6,941	26	26
Total retail	728,534	734,475	8,861	9,023
Wholesale	102,736	78,305	3,733	2,796
Sales of fuel	115,835	153,470	—	—
Other	21,067	21,937	—	—
Total	$ 968,172	$ 988,187	12,594	11,819

Retail electric revenues decreased $5.9 million due to a decrease in total MWhs sold (decreased revenues $13.3 million) offset by an increase in revenue per MWh (increased revenues $7.3 million). The decrease in MWhs sold was primarily the result of warmer weather during the heating season, and due in part to lower usage at certain industrial customers due to temporary operational challenges. This was partially offset during the cooling season due to warmer weather (and increased loads), which increased electric use per customer. Compared to 2011, residential electric use per customer decreased 4 percent. Cooling degree days at Spokane were 23 percent above historical average for 2012 and were 26 percent above 2011. Heating degree days at Spokane were 6 percent below historical average for 2012, and 9 percent below 2011. The increase in revenue per MWh was primarily due to the Washington and Idaho general rate increases.

Wholesale electric revenues increased $24.4 million due to an increase in sales volumes (increased revenues $25.8 million), partially offset by a decrease in sales prices (decreased revenues $1.4 million). The increase in sales volumes was primarily due to the fact that our retail sales were lower than expected, as discussed above, and we sold the resulting excess capacity, energy and fuel on the wholesale market through our optimization procedures.

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market rather than operate the generating units. The revenues from sales of fuel decreased $37.6 million due to a decrease in sales of natural gas fuel as part of thermal generation resource optimization activities and higher usage of our thermal generation plants in 2012 as compared to 2011, as well as a decrease in natural gas prices. Higher usage of our thermal generation plants was due in part to decreased hydroelectric generation. For 2012, $45.3 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For 2011, $38.6 million of these sales were made to our natural gas operations.

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

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

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2012	2011	2012	2011
Residential	$ 196,719	$ 219,557	189,152	207,202
Commercial	98,994	111,964	115,083	125,344
Interruptible	2,232	2,519	4,363	4,503
Industrial	3,635	4,180	5,073	5,654
Total retail	301,580	338,220	313,671	342,703
Wholesale	158,631	195,882	586,193	510,755
Transportation	7,032	6,709	154,704	152,515
Other	6,930	7,414	381	440
Total	$ 474,173	$ 548,225	1,054,949	1,006,413

Retail natural gas revenues decreased $36.6 million primarily due to a decrease in volumes (decreased revenues $27.9 million) and lower retail rates (decreased revenues $8.7 million). We sold less retail natural gas in 2012 as compared to 2011 primarily due to warmer weather. Compared to 2011, residential and commercial natural gas use per customer decreased 9 percent. Heating degree days at Spokane were 6 percent below historical average for 2012, and 9 percent below 2011. Heating degree days at Medford were 5 percent below historical average for 2012, and 10 percent below 2011.

Wholesale natural gas revenues decreased $37.3 million due to a decrease in prices (decreased revenues $57.7 million), partially offset by an increase in volumes (increased revenues $20.4 million). We plan for sufficient natural gas capacity to serve our retail customers on a theoretical peak day. As such, on nonpeak days we generally have more pipeline and storage capacity than what is needed for retail loads. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that partially offsets net natural gas costs. In some situations, customer demand is below the amount hedged and we sell natural gas in excess of load requirements. In 2012, $42.9 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In 2011, $54.5 million of these sales were made to our electric generation operations. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.

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

	Electric Customers		Natural Gas Customers	
	2012	2011	2012	2011
Residential	318,692	316,762	286,522	284,504
Commercial	39,869	39,618	33,763	33,540
Interruptible	—	—	38	38
Industrial	1,395	1,380	263	255
Public street and highway lighting	503	455	—	—
Total retail customers	360,459	358,215	320,586	318,337

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

	2012	2011
Electric resource costs:		
Power purchased	$ 194,088	$ 169,845
Power cost amortizations, net	12,784	31,910
Fuel for generation	90,029	84,367
Other fuel costs	120,074	164,173
Other regulatory amortizations, net	15,665	16,381
Other electric resource costs	18,794	17,683
Total electric resource costs	451,434	484,359
Natural gas resource costs:		
Natural gas purchased	327,458	396,497
Natural gas cost amortizations, net	(5,804)	(10,041)
Other regulatory amortizations, net	8,199	12,323
Total natural gas resource costs	329,853	398,779
Intracompany resource costs	(88,160)	(93,090)
Total resource costs	$ 693,127	$ 790,048

Power purchased increased $24.2 million due to an increase in the volume of power purchases (increased costs $26.7 million), partially offset by a decrease in wholesale prices (decreased costs $2.4 million).

Net amortization of deferred power costs was $12.8 million for 2012 compared to $31.9 million for 2011. During 2012, we recovered (collected as revenue) $1.3 million of previously deferred power costs in Idaho through the PCA surcharge. The Washington ERM surcharge was eliminated in February 2010, since the previous balance of deferred power costs had been recovered. During 2012, actual power supply costs were below the amount included in base retail rates and we deferred $8.9 million in Washington and $2.6 million in Idaho for potential future rebate to customers.

Fuel for generation increased $5.7 million primarily due to an increase in thermal generation. This was due in part to a decrease in hydroelectric generation. The increase in thermal generation usage was partially offset by a decrease in natural gas fuel prices.

Other fuel costs decreased $44.1 million. This represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation, as part of the resource optimization process. When the fuel is sold, the revenue generated from selling the fuel is included in the sales of fuel revenue line item above.

The expense for natural gas purchased decreased $69.0 million due to a decrease in the price of natural gas (decreased costs $85.9 million), partially offset by an increase in total therms purchased (increased costs $16.9 million). Total therms purchased increased due to an increase in wholesale sales which are used to balance loads and resources as part of the natural gas procurement and resource optimization process. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs.

2011 compared to 2010

Net income for Avista Utilities was $90.9 million for 2011, an increase from $86.7 million for 2010. Avista Utilities' income from operations was $202.4 million for 2011 compared to $198.2 million for 2010. The increase in net income and income from operations was primarily due to an increase in gross margin (operating revenues less resource costs), partially offset by an increase in other operating expenses, depreciation and amortization, and taxes other than income taxes. The increase in net income from Avista Utilities was also due to a decrease in interest expense (net of capitalized interest) and a decrease in donations (included in other income-net).

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

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

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

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

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

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

Retail electric revenues increased $51.1 million due to an increase in total MWhs sold (increased revenues $14.6 million) primarily due to an increase in use per customer as a result of colder weather, and an increase in revenue per MWh (increased revenues $36.5 million). Compared to 2010, residential electric use per customer increased 3 percent. The increase in revenue per MWh was primarily due to the Washington and Idaho general rate increases.

Wholesale electric revenues decreased $87.2 million due to a decrease in sales prices (decreased revenues $59.0 million) and a decrease in sales volumes (decreased revenues $28.2 million). The decrease in sales volumes was primarily due to decreased wholesale power optimization and higher than expected retail sales caused by colder weather in the first quarter.

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

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

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

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

Retail natural gas revenues increased $40.3 million due to an increase in volumes (increased revenues $30.6 million) and higher retail rates (increased revenues $9.7 million). We sold more retail natural gas in 2011 as compared to 2010 primarily due to colder weather in the heating season. Compared to 2010, residential natural gas use per customer increased 9 percent and commercial use per customer increased 10 percent. The increase in retail rates reflects purchased gas adjustments, as well as general rate increases.

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

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

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

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

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

Power purchased decreased $16.5 million due to a decrease in the volume of power purchases (decreased costs $18.0 million), partially offset by a slight increase in wholesale prices (increased costs $1.5 million). The decrease in the volume of the power purchases was due in part to an increase in hydroelectric generation.

Net amortization of deferred power costs was $31.9 million for 2011 compared to $2.8 million for 2010. During 2011, we recovered (collected as revenue) $14.9 million of previously deferred power costs in Idaho through the PCA surcharge. The Washington ERM surcharge was eliminated in February 2010, since the previous balance of deferred power costs had been recovered. During 2011, actual power supply costs were below the amount included in base retail rates in both Washington and Idaho. This was due to improved hydroelectric generation and lower purchased power and fuel costs. As such, we deferred $4.2 million in Idaho and $12.8 million in Washington for potential future rebate to customers.

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

Other fuel costs increased $50.0 million. This represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation, as part of the resource optimization process. The associated revenues are reflected as sales of fuel.

The expense for natural gas purchased increased $9.7 million due to an increase in total therms purchased (increased costs $31.0 million), partially offset by a decrease in the price of natural gas (decreased costs $21.3 million). Total therms purchased increased due to an increase in retail loads (resulting from colder weather in the heating season) and an increase in wholesale sales with the balancing of loads and resources as part of the natural gas procurement and resource optimization process. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs. During 2011, natural gas resource costs were reduced by $10.0 million reflecting the rebate of a deferred liability for natural gas costs through the purchased gas adjustments.

Ecova

2012 compared to 2011

Ecova's net income attributable to Avista Corp. shareholders was $1.8 million for 2012 compared to net income of $9.7 million for 2011. Operating revenues increased $17.8 million and total operating expenses increased $35.8 million. The increase in operating revenues was primarily the result of the acquisitions of Prenova effective November 30, 2011 and LPB effective January 31, 2012, which added $22.5 million to operating revenues for 2012 over 2011 revenues. In addition, there were delays associated with the process of onboarding new customers onto the monitoring system for energy management services due to m ore complex customers and systems, and there was a reduction in revenues related to the deconsolidation of a partnership. This, combined with the increased operating expenses has contributed to a net decrease in net income attributable to Avista Corp. shareholders.

The increase in total operating expenses primarily reflects increased costs necessary to support ongoing and future business growth, as well as to support the increased revenue volume obtained through the acquisitions. There were increases in employee costs of $20.5 million, facilities costs of $1.7 million, and information technology costs and professional fees of $4.6 million. In addition, Ecova incurred $2.6 million in transaction and integration costs. Depreciation and amortization increased $6.3 million due to intangibles recorded in connection with the acquisitions. Included in the increased depreciation and amortization is an impairment loss of $1.1 million pre-tax ($0.7 million after-tax) related to the write-off of internally developed software during the fourth quarter of 2012.

As of December 31, 2012, Ecova had 740 expense management customers representing 697,076 billed sites in North America. In 2012, Ecova managed bills totaling $19.4 billion, an increase of $1.1 billion as compared to 2011. This increase was due to an increase in the number of accounts managed (mostly due to acquisitions), partially offset by a decrease in the average value of each bill (due in part to a decline in natural gas rates). The increases in the number of accounts and the total bills managed indicates an increase in the use of Ecova's services and provides support for potential future revenue growth.

2011 compared to 2010

Ecova's net income attributable to Avista Corp. shareholders was $9.7 million for 2011 compared to $7.4 million for 2010. Operating revenues increased $35.8 million and total operating expenses increased $30.8 million. The increase in operating revenues was primarily due to growth in energy management and expense management services, as well as the acquisition of Loyalton effective December 31, 2010, which added $8.5 million to 2011 operating revenues. Ecova's organic revenue growth was approximately 13 percent from 2010 to 2011. The increase in operating expenses primarily reflects increased costs necessary for business growth and the acquisition of Loyalton. The acquisition of Prenova, effective November 30, 2011, had minimal impact to 2011 results. During the fourth quarter of 2011, Ecova determined that certain revenues, which had previously been reported net of expenses, should be reported on a gross basis. This increased operating revenues and expenses by $9.2 million with no impact to net income for 2011. As of December 31, 2011, Ecova had 645 expense management customers representing 496,842 billed sites in North America. In 2011, Ecova managed bills totaling $18.3 billion, an increase of $1.0 billion as compared to 2010.

Other Businesses

2012 compared to 2011

The net loss from these operations was $5.3 million for 2012 compared to a net loss of $0.3 million for 2011. The decline in results was due in part to losses on investments of $3.3 million for 2012 compared to $0.5 million for 2011. The losses for 2012 were primarily the result of an impairment loss of $2.4 million pre-tax ($1.5 million after-tax) recognized during the third quarter of 2012 related to the impairment of our investment in a fuel cell business and the write-off of our investment in a solar energy company. Additionally, there were increased costs associated with strategic consulting and other corporate costs of $2.3 million and litigation costs related to the previous operations of Avista Energy of $1.5 million. These losses were partially offset by METALfx which had net income of $1.2 million for 2012 and $1.4 million for 2011.

2011 compared to 2010

The net loss from these operations was $0.3 million for 2011 compared to $1.7 million for 2010. Operating revenues decreased $20.7 million and total operating expenses decreased $19.7 million. The decrease in operating revenues and operating expenses was primarily due to the assignment of the Lancaster PPA to Avista Corp. in December 2010. Earnings from METALfx increased to $1.4 million for 2011 compared to $0.8 million for 2010. Losses on investments were $0.5 million for 2011 compared to losses of $3.3 million for 2010. The loss for 2010 included a $2.2 million impairment of our investment in a fuel cell business.

Accounting Standards to be Adopted in 2013

At this time, we are not expecting the adoption of accounting standards to have a material impact on our financial condition, results of operations and cash flows in 2013. For information on accounting standards adopted in 2012 and earlier periods, see "Note 2 of the Notes to Consolidated Financial Statements."

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires us to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on our consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein. The following accounting policies represent those that our management believes are particularly important to the consolidated financial statements that require the use of estimates and assumptions:

Avista Utilities Operating Revenues

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

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

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

Regulatory Accounting

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

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

Utility Energy Commodity Derivative Assets and Liabilities

Our utility enters into forward contracts to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. These contracts are entered into as part of our management of loads and resources and certain contracts are considered derivative instruments. The UTC 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 approves investment policies, objectives and strategies that seek an appropriate return for the pension plan and it reviews and approves changes to the investment and funding policies.

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

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

We also have a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to our executive officers whose benefits under the pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans.

Pension costs (including the SERP) were $28.1 million in 2012, $23.9 million for 2011 and $21.3 million for 2010. 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. The SERP is available to all new executive officers.

Pension costs are affected by:

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

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

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

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

We have not made any changes to pension plan provisions in 2012, 2011 and 2010 that have had any significant effect on our recorded pension plan amounts. We have revised the key assumption of the discount rate in 2012, 2011 and 2010. Such changes had an effect on our pension costs in 2012, 2011 and 2010 and may affect future years, given the cost recognition approach described above. However, in determining pension obligation and cost amounts, our assumptions can change from period to period, and such changes could result in material changes to our future pension costs and funding requirements.

In selecting a discount rate, we consider yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits. In 2012, we decreased the pension plan discount rate (exclusive of the SERP) to 4.15 percent from 5.05 percent in 2011. We used a discount rate of 5.70 percent in 2010. This increased the projected benefit obligation (exclusive of the SERP) by approximately $66.5 million in 2012 and $40.0 million in 2011.

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by our plan. We used an expected long-term rate of return of 6.95 percent in 2012, 7.40 percent in 2011 and 7.75 percent in 2010. This increased pension costs by approximately $1.5 million in 2012 and by approximately $1.1 million in 2011. The actual return on plan assets, net of fees, was a gain of $54.3 million (or 15.9 percent) for 2012, a gain of $14.7 million (or 4.8 percent) for 2011 and a gain of $29.8 million (or 10.9 percent) for 2010. We periodically analyze the estimated long-term rate of return on assets based upon updated economic forecasts and revisions to the investment portfolio.

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

Actuarial Assumption	Change in Assumption	Effect on Projected Benefit Obligation	Effect on Pension Cost
Expected long-term return on plan assets	(0.5)%	$ — *	$ 1,713
Expected long-term return on plan assets	0.5 %	— *	(1,713)
Discount rate	(0.5)%	43,473	3,380
Discount rate	0.5 %	(38,647)	(3,041)

* 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, 2012 by $20.8 million and the service and interest cost by $1.4 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, 2012 by $16.7 million and the service and interest cost by $1.1 million.

Goodwill

We evaluate goodwill for impairment using a discounted cash flow model on at least an annual basis or more frequently if impairment indicators arise. Examples of impairment indicators include: a deterioration in general economic conditions, market considerations such as a deterioration in the environment in which the entity operates, a decline in market-dependent multiples or metrics, increases in costs, overall financial performance such as a decline in earnings or cash flows, or a loss of key customers.

The annual evaluation of goodwill for potential impairment is completed as of December 31 for Ecova and as of November 30 for our other businesses. As of December 31, 2012, we had goodwill of $70.7 million related to Ecova and $5.2 million related to our other businesses. Our goodwill at Ecova has increased significantly in 2011 and 2012 with the acquisitions of Prenova and LPB.

Application of the goodwill impairment test requires judgment and the use of significant estimates, including the identification of reporting units, assignment of assets and liabilities to reporting units, and the estimation of the fair value of reporting units. The goodwill impairment test is a two-step process performed at the reporting unit level. The first step involves comparing the carrying amount of the reporting unit to its estimated fair value. If the estimated fair value of the reporting unit is greater than its carrying value, the goodwill impairment test is complete and no impairment is recorded. If the estimated fair value of the reporting unit is less than its carrying value, the second step of the test is performed to determine the amount of impairment loss, if any. This would result in a full valuation of the reporting units assets and liabilities and comparing the valuation to its carrying amounts, with the aggregate difference indicating the amount of impairment. In 2012, 2011 and 2010, each reporting unit that has been evaluated for impairment has passed the first step of the test, and no impairment losses have been recorded.

Contingencies

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

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

Liquidity and Capital Resources

Review of Cash Flow Statement

Overall During 2012, positive cash flows from operating activities of $316.6 million, proceeds from the issuance of long-term debt of $80.0 million, $19.0 million of borrowings under Ecova's committed line of credit, and the issuance of $29.1 million (net of issuance costs) of common stock were used to fund the majority of our cash requirements. These cash requirements included utility capital expenditures of $271.2 million, cash paid for the acquisition of LPB of $50.3 million and dividends of $68.6 million.

Operating Activities Net cash provided by operating activities was $316.6 million for 2012 compared to $269.5 million for 2011. Net cash provided by working capital components was $63.6 million for 2012, compared to net cash used of $14.9 million for 2011. The net cash provided during 2012 primarily reflects positive cash flows from other current assets (primarily related to a decrease in deposits with counterparties and income taxes receivable) and net cash inflows related to accounts payable.

The net cash used during 2011 primarily reflects negative cash flows from other current assets (primarily related to an increase in deposits with counterparties), net cash outflows related to accounts payable and an increase in natural gas stored. These negative cash flows were partially offset by net cash inflows related to accounts receivable.

Net amortization of deferred power and natural gas costs was $6.7 million for 2012 compared to $21.9 million for 2011. The provision for deferred income taxes was $21.4 million for 2012 compared to $24.0 million for 2011. Contributions to our defined benefit pension plan were $44.0 million for 2012 compared to $26.0 million for 2011. Cash paid for interest was $74.9 million for 2012, compared to $69.1 million for 2011.

Investing Activities Net cash used in investing activities was $294.7 million for 2012, an increase compared to $282.3 million for 2011. Utility property capital expenditures increased by $31.4 million for 2012 as compared to 2011. In 2012, a significant portion of Ecova's funds held for clients were held as securities available for sale (purchases of $100.4 million and sales and maturities of $138.0 million). At the end of 2011, the majority of Ecova's funds held for clients were held as securities available for sale (purchases of $96.6 million). The net cash paid by subsidiaries for acquisitions in 2012 of $50.3 million represents Ecova's acquisition of LPB. The net cash paid by subsidiaries for acquisitions in 2011 of $31.4 million primarily represents Ecova's acquisition of Prenova.

Financing Activities Net cash used in financing activities was $21.1 million for 2012 compared to net cash provided of $18.1 million for 2011. During 2012, short-term borrowings on Avista Corp.'s committed line of credit decreased $9.0 million. Borrowings on Ecova's committed line of credit increased $19.0 million (net of borrowings of $33.0 million and repayments of $14.0 million) and these proceeds were used to fund a portion of the acquisition of LPB. Cash dividends paid increased to $68.6 million (or $1.16 per share) for 2012 from $63.7 million (or $1.10 per share) for 2011. We issued $29.1 million of common stock during 2012. We cash settled interest rate swap agreements for $18.5 million related to the pricing of $80.0 million of long-term debt issued in November 2012. Customer fund obligations at Ecova decreased $31.0 million.

During 2011, short-term borrowings on Avista Corp.'s committed line of credit decreased $49.0 million. Borrowings on Ecova's committed line of credit increased $35.0 million and these proceeds were used to fund the acquisition of Prenova. We issued $26.5 million of common stock during 2011. We cash settled interest rate swap agreements for $10.6 million related to the pricing of $85.0 million of long-term debt issued in December 2011. Customer fund obligations at Ecova increased $17.8 million.

Overall Liquidity

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

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

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

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

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

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

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

As of December 31, 2012, we had $312.1 million of available liquidity under our committed line of credit. With our $400.0 million credit facility that expires in February 2017, we believe that we have adequate liquidity to meet our needs for the next 12 months.

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

Collateral Requirements

Our contracts for the purchase and sale of energy commodities can require collateral in the form of cash or letters of credit. As of December 31, 2012, we had cash deposited as collateral of $10.1 million and letters of credit of $28.1 million outstanding related to our energy derivative contracts. Price movements and/or a downgrade in our credit ratings could impact further the amount of collateral required. See “Credit Ratings” for further information. For example, in addition to limiting our ability to conduct transactions, if our credit ratings were lowered to below “investment grade” based on our positions outstanding at December 31, 2012, we would potentially be required to post additional collateral of up to $19.3 million. This amount is different from the amount disclosed in “Note 6 of the Notes to Consolidated Financial Statements” because, while this analysis includes contracts that are not considered derivatives in addition to the contracts considered in Note 6, this analysis takes into account contractual threshold limits that are not considered in Note 6. Without contractual threshold limits, we would potentially be required to post additional collateral of $43.4 million.

Under the terms of interest rate swap agreements that we enter into periodically, we may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the instrument. This has not historically been significant to our liquidity position. As of December 31, 2012, we had interest rate swap agreements outstanding with a notional amount totaling $160 million and we did not have any collateral posted. If our credit ratings were lowered to below “investment grade” based on our interest rate swap agreements outstanding at December 31, 2012, we would not be required to post additional collateral.

Dodd-Frank Wall Street Reform and Consumer Protection Act

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

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

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

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

In July 2012, the CFTC issued a final rule providing for an exemption from clearing requirements as outlined in Dodd-Frank for end users that enter into hedges to mitigate commercial risk. We expect most of our transactions to qualify under the end user exemption, however we may choose to use a clearing agent for many transactions even if we are allowed bilateral transactions. During 2012, the Board of Directors of Avista Corp. approved the use of the end user exemption, if we choose to utilize this exemption.

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

Capital Resources

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings, and excluding noncontrolling interests, consisted of the following as of December 31, 2012 and 2011 (dollars in thousands):

	December 31, 2012		December 31, 2011	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 50,372	1.9%	$ 7,474	0.3%
Current portion of nonrecourse long-term debt (Spokane Energy)	14,965	0.6%	13,668	0.5%
Short-term borrowings	52,000	1.9%	96,000	3.8%
Long-term borrowings under committed line of credit	54,000	2.0%	—	—%
Long-term debt to affiliated trusts	51,547	1.9%	51,547	2.0%
Nonrecourse long-term debt (Spokane Energy)	17,838	0.7%	32,803	1.3%
Long-term debt	1,178,367	44.0%	1,169,826	45.7%
Total debt	1,419,089	53.0%	1,371,318	53.6%
Total Avista Corporation stockholders' equity	1,259,477	47.0%	1,185,701	46.4%
Total	$ 2,678,566	100.0%	$ 2,557,019	100.0%

We need to finance capital expenditures and acquire additional funds for operations from time to time. The cash requirements needed to service our indebtedness, both short-term and long-term, reduce the amount of cash flow available to fund capital expenditures, purchased power, fuel and natural gas costs, dividends and other requirements. Our stockholders' equity increased $73.8 million during 2012 primarily due to net income, the issuance of common stock, and the expiration of the subsidiary noncontrolling interests redemption rights, partially offset by dividends.

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

In August 2012, we entered into two sales agency agreements under which we may sell up to 2.7 million shares of our common stock from time to time. In 2012, we sold 0.9 million shares for a total of $23.4 million (net of issuance costs). As of December 31, 2012, we had 1.8 million shares available to be issued under these agreements.

We are planning to issue up to $50.0 million of common stock in 2013 in order to maintain our capital structure at an appropriate level for our business. In 2012, we issued $29.1 million (net of issuance costs) of common stock. The additional shares were issued under sales agency agreements, as well as the dividend reinvestment and direct stock purchase plan and employee plans.

In November 2012, we issued $80.0 million of 4.23 percent First Mortgage Bonds due in 2047. The net proceeds from the sale of the bonds were used to repay a portion of the borrowings outstanding under our $400.0 million committed line of credit. In connection with the pricing of the First Mortgage Bonds, we cash settled interest rate swap contracts and paid a total of $18.5 million, which will be amortized as a component of interest expense over the life of the debt. There are $50.0 million in First Mortgage Bonds maturing in 2013 and we expect to issue up to $100.0 million of long-term debt during the second half of 2013.

We have a committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2017. Borrowings under this line of credit agreement are classified as short-term on the Consolidated Balance Sheets.

This facility contains customary covenants and default provisions, including a covenant which does not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 65 percent at any time. As of December 31, 2012, we were in compliance with this covenant with a ratio of 53.0 percent.

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

	2012	2011	2010
Balance outstanding at end of year	$ 52,000	$ 61,000	$ 110,000
Letters of credit outstanding at end of year	$ 35,885	$ 29,030	$ 27,126
Maximum balance outstanding during the year	$ 92,500	$ 130,000	$ 170,000
Average balance outstanding during the year	$ 23,921	$ 74,947	$ 80,230
Average interest rate during the year	1.18%	1.43%	0.60%
Average interest rate at end of year	1.12%	1.12%	0.57%

The decrease in the average balance outstanding was due in part to a new intercompany borrowing arrangement between Avista Corp. and Ecova. As part of their cash management practices and operations, Ecova and Avista Corp. entered into an arrangement in January 2012 under which (1) Avista Corp. issued to Ecova a master unsecured promissory note and (2) Ecova will from time to time make short-term loans to Avista Corp. as a temporary investment of its funds received from its clients. The master promissory note limits the total outstanding indebtedness to no more than $50.0 million in principal. Additionally, such loans are required to be repaid on the last business day of each quarter (March, June, September and December) and sooner upon demand by Ecova. Amounts are loaned at a rate consistent with Avista Corp.'s credit facility. The average balance outstanding was $31.6 million and the maximum balance was $50.0 million during 2012.

Any default on the line of credit or other financing arrangements of Avista Corp. or any of our “significant subsidiaries,” if any, could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Any defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock. Avista Corp. does not guarantee the indebtedness of any of its subsidiaries. As of December 31, 2012, Avista Corp. and its subsidiaries were in compliance with all of the covenants of their financing agreements, and none of Avista Corp.'s subsidiaries constituted a “significant subsidiary” as defined in Avista Corp.'s committed line of credit.

Ecova also has a committed line of credit agreement with various financial institutions for $125.0 million with an expiration date of July 2017. This credit agreement is used primarily to fund acquisitions at Ecova and supplement cash flow for Ecova's operations when necessary and is generally not available for capital acquisitions. There were $54.0 million of borrowings outstanding under Ecova’s credit agreement as of December 31, 2012 classified as long-term. See the "Ecova Credit Agreement" section below for further discussion regarding this agreement.

We are restricted under our Restated Articles of Incorporation, as amended, as to the additional preferred stock we can issue. As of December 31, 2012, we could issue $876.7 million of additional preferred stock at an assumed dividend rate of 6.0 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:

- 66-2/3 percent of the cost or fair value (whichever is lower) of property additions which have not previously been made the basis of any application under the Mortgage, or
- an equal principal amount of retired First Mortgage Bonds which have not previously been made the basis of any application under the Mortgage, or
- deposit of cash.

However, we may not issue any additional First Mortgage Bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless our “net earnings” (as defined in the Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the First Mortgage Bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2012, our property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $640.1 million in aggregate principal amount of additional First Mortgage Bonds. We believe that we have adequate capacity to issue First Mortgage Bonds to meet our financing needs over the next several years.

Avista Utilities Capital Expenditures

Capital expenditures for our utility were $713.2 million for the years 2010 through 2012. We expect utility capital expenditures to be about $260 million for each of 2013, 2014 and 2015. Our capital budget for 2013 includes the following (dollars in millions):

Transmission and distribution (upgrade current facilities)	$	85
Information technology		53
Customer growth (incremental transmission and distribution)		28
Generation		36
Natural gas		23
Facilities		17
Environmental		14
Other		10
Total	$	266

Most of the capital expenditures above are for upgrading and maintenance of our existing facilities, and not for construction of new facilities and we expect all of these capital expenditures to be included in rate base in future years. These estimates of capital expenditures are subject to continuing review and adjustment. Actual capital expenditures may vary from our estimates due to factors such as changes in business conditions, construction schedules and environmental requirements.

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

Included in our estimates of capital expenditures is the replacement of our customer information and work management systems, which is expected to be completed by the end of 2014. Our customer information system and work management systems are two of our most critical technology systems and are interconnected to every other system in our company. We expect to spend a total of approximately $80 million (including internal labor) over the term of the project. Major signed contracts for third parties total approximately $25 million as of December 31, 2012.

Ecova Credit Agreement

In July 2012, Ecova entered into a $125.0 million committed line of credit agreement with various financial institutions that replaced its $60.0 million committed line of credit agreement and has an expiration date of July 2017. The credit agreement is secured by all of Ecova's assets excluding investments and funds held for clients. There were $54.0 million of borrowings outstanding under Ecova’s credit agreement as of December 31, 2012 classified as long-term. The proceeds from these borrowings were used to fund the acquisitions of Prenova in November 2011 and LPB in January 2012.

The committed line of credit agreement contains customary covenants and default provisions, including a covenant which requires that Ecova's “Consolidated Total Funded Debt to EBITDA Ratio” (as defined in the credit agreement) must be 2.50 to 1.00 or less, with provisions in the credit agreement allowing for a temporary increase of this ratio if a qualified acquisition is consummated by Ecova. In addition, Ecova's “Consolidated Fixed Charge Coverage Ratio” (as defined in the credit agreement) must be greater than 1.50 to 1.00 as of the last day of any fiscal quarter. As of December 31, 2012, Ecova was in compliance with these covenants and based on the Consolidated Total Funded Debt to EBITDA Ratio, Ecova could borrow an additional $5.6 million and still be compliant with the covenants. The covenant restrictions are calculated on a rolling twelve month basis, so this additional borrowing capacity could increase or decrease or Ecova could be required to pay down the outstanding debt as future results change. We expect Ecova's earnings to increase in the future, so we expect the excess borrowing capacity to increase as well.

Ecova Redeemable Stock

Ecova's amended employee stock incentive plan provides an annual window at which time holders of common stock can put their shares back to Ecova, providing the shares are held for a minimum of six months. Stock is reacquired at fair market value at the date of reacquisition. As the repurchase feature is at the discretion of the minority shareholders and option holders, there were redeemable noncontrolling interests of $4.9 million as of December 31, 2012 for the intrinsic value of stock options outstanding, as well as outstanding redeemable stock. In 2009, the Ecova employee stock incentive plan was amended such that, on a prospective basis, not all options granted under the plan have the put right. Additionally, there were redeemable noncontrolling interests related to the 2008 Cadence Network acquisition, as the previous owners could have exercised a right to put their stock back to Ecova in July 2011 or July 2012 if their investment in Ecova was not liquidated through either an initial public offering or sale of the business to a third party. These redemption rights were not exercised, expired effective July 31, 2012 and were reclassified to permanent equity.

Off-Balance Sheet Arrangements

As of December 31, 2012, we had $35.9 million in letters of credit outstanding under our $400.0 million committed line of credit, compared to $29.0 million as of December 31, 2011.

Pension Plan

As of December 31, 2012, our pension plan had assets with a fair value that was less than the benefit obligation under the plan. The pension plan funding deficit (as measured under ASC 715) increased in 2012 primarily due to a decrease in the discount rate. In 2012, the Moving Ahead for Progress in the 21 st Century (MAP-21) Federal legislation was approved that changed how the required discount rate was calculated for funding purposes, impacting the minimum required contributions as determined by ERISA federal regulations and the Internal Revenue Code. The change in law required the discount rate (for the target liability) to be calculated over a 25 year average versus the previously required 2 year average. Although the legislation was not passed until late 2012, the change in discount rate was retroactively effective to January 1, 2012. This significantly increased the discount rate resulting in a lower target liability. The funded status, as determined by ERISA federal regulations and the Internal Revenue Code, for our plan increased from approximately 80 percent to 102 percent without any other changes as of January 1, 2012. We contributed $44 million to the pension plan in 2012. We expect to contribute a total of $148.5 million to the pension plan in the period 2013 through 2016, with contributions of $44 million per year for the period 2013 to 2015 and a contribution of $16.5 million in 2016. Our contribution is expected to decrease in 2016 as we move toward fully funded status. The final determination of pension plan contributions for future periods is subject to multiple variables, most of which are beyond our control, including further changes to the fair value of pension plan assets, changes in actuarial assumptions (in particular the discount rate used in determining the benefit obligation), or changes in federal legislation. We may change our pension plan contributions in the future depending on changes to any of the above variables.

Credit Ratings

Our access to capital markets and our cost of capital are directly affected by our credit ratings. In addition, many of our contracts for the purchase and sale of energy commodities contain terms dependent upon our credit ratings. See "Collateral Requirements" and "Note 6 of the Notes to Consolidated Financial Statements." The following table summarizes our credit ratings as of February 26, 2013:

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

(1) Standard & Poor's lowest "investment grade" credit rating is BBB-.
(2) Moody's lowest "investment grade" credit rating is Baa3.

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

Dividends

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

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

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

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

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

Contractual Obligations

The following table provides a summary of our future contractual obligations as of December 31, 2012 (dollars in millions):

	2013	2014	2015	2016	2017	Thereafter
Avista Utilities:						
Long-term debt maturities	$ 50	$ —	$ —	$ —	$ —	$ 1,203
Long-term debt to affiliated trusts	—	—	—	—	—	52
Interest payments on long-term debt (1)	67	66	66	66	66	679
Short-term borrowings	52	—	—	—	—	—
Energy purchase contracts (2)	306	228	196	178	169	1,704
Public Utility District contracts (2)	3	3	3	3	3	43
Operating lease obligations (3)	2	2	—	—	—	3
Other obligations (4)	31	32	29	36	28	230
Information technology contracts (8)	15	22	18	9	9	1
Pension plan funding (5)	44	44	44	17	—	—
Spokane Energy:						
Nonrecourse long-term debt maturities	15	16	1	—	—	—
Interest payments on nonrecourse long-term debt	2	1	—	—	—	—
Avista Capital (consolidated):						
Redeemable noncontrolling interests (6)	5	—	—	—	—	—
Long-term borrowings under committed line of credit	—	—	—	—	54	—
Interest payments on long-term borrowings under committed line of credit (1)	1	1	1	1	1	—
Venture funds investments (7)	2	—	—	—	—	—
Operating lease obligations (3)	5	5	3	2	1	2
Client fund obligations	88	—	—	—	—	—
Total contractual obligations	$ 688	$ 420	$ 361	$ 312	$ 331	$ 3,917

(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, 2012.

(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 2016. We cannot reasonably estimate pension plan contributions beyond 2016 at this time and have excluded them from the table above.

(6) Certain shares acquired under Ecova's employee stock incentive plan are redeemable at the option of the shareholder.

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

(8) Includes information service contracts which are recorded to other operating expenses in the Consolidated Statements of Income as well as information technology contracts associated with the replacement of our customer information and work management systems, which are capital expenditures and expected to be completed in 2014.

The above contractual obligations do not include income tax payments. Also, asset retirement obligations are not included above and payments associated with these have historically been less than $1 million per year. There are approximately $3.2 million remaining asset retirement obligations as of December 31, 2012.

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

Competition

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

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

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

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

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

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

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

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

Participants in the wholesale energy markets include:

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

Ecova is subject to competition for service to existing customers and as they develop products and services and enter new markets. Competition from other companies may mean challenges for Ecova to be the first to market a new product or service to gain an advantage in market share. In addition, Ecova's services utilize rapidly advancing technologies which require continual product enhancement to avoid obsolescence.

Economic Conditions and Utility Load Growth

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

We track multiple economic indicators affecting three distinct metropolitan areas in our service area: Spokane, Washington, Coeur d'Alene, Idaho, and Medford, Oregon. Several key indicators are employment change, unemployment rates and foreclosure rates. On a year-over-year basis, December 2012 showed positive job growth, and lower unemployment rates in all three metropolitan areas. Foreclosure rates are in line with or below the U.S rate in all three areas. However, the unemployment rates are still above the national average and two key leading indicators, initial unemployment claims and residential building permits, continue to signal modest growth over the next 12 months. Therefore, in 2013, we continue to expect economic growth in our service area to be somewhat slower than the U.S. as a whole.

Seasonally adjusted nonfarm employment in our eastern Washington, northern Idaho, and southwestern Oregon metropolitan service areas exhibited moderate growth between December 2011 and December 2012. In Spokane, Washington employment growth was 1.4 percent with gains in mining, logging, and construction; leisure and hospitality; and business and professional services. Employment increased by 3.2 percent in Coeur d'Alene, Idaho, reflecting gains in construction; professional and business services; financial activities; trade, transport, and utilities; and education and health services. In Medford, Oregon, employment growth was 4.3 percent, with gains in manufacturing; construction; trade, transport, and utilities; leisure and hospitality; and financial activities. U.S. nonfarm sector jobs grew by 1.4 percent in the same twelve-month period.

Seasonally adjusted unemployment rates went down in December 2012 from the year earlier in Spokane, Coeur d'Alene, and Medford. In Spokane the rate was 9.2 percent in December 2011 and declined to 8.5 percent in December 2012; in Coeur d'Alene the rate went from 9.7 percent to 7.8 percent; and in Medford the rate declined from 11.2 percent to 10.4 percent. The U.S. rate declined from 8.5 percent to 7.8 percent in the same period.

The housing market in our service area continues to experience foreclosure rates in line with or lower than the national average. The December 2012 national rate was 0.12 percent, compared to 0.15 percent in Spokane County, Washington; 0.13 percent in Kootenai County (Coeur d'Alene), Idaho; and 0.01 percent in Jackson County (Medford), Oregon.

Based on our forecast for 2013 through 2016, we expect annual electric customer growth to average 0.7 percent to 1.3 percent per year and annual natural gas customer growth to average 0.7 percent to 1.8 percent within our service area. We anticipate retail electric load growth to average between 0.7 percent and 1.0 percent and natural gas load growth to average between 0.7 percent and 1.4 percent. We anticipate customer and load growth at the lower end of the range in 2013 and a modest recovery as the economy strengthens during the four-year period. While the number of electric and natural gas customers is growing, the average annual usage by each residential customer has not changed significantly. Growth in electric and natural gas sales has slowed as retail prices have increased and Company sponsored conservation programs have intensified. With a weaker than normal post-recession recovery in Avista's service area, population and business growth in our three-state service territory remains at or below the national average. In addition to the foregoing, electric and natural gas sales vary significantly with annual fluctuations in weather within our service territories.

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

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

Changes in actual experience can vary significantly from our projections.

Environmental Issues and Contingencies

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

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

Environmental laws and regulations may:

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

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

Clean Air Act

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

On July 30, 2012, we received a Notice of Intent to Sue for violations of the Clean Air Act at Colstrip Steam Electric Station (Notice) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). An Amended Notice was received on September 4, 2012, and Supplemental Notices were received in October and December 2012. We are evaluating the allegations set forth in the Notices and cannot at this time predict the outcome of this matter. See “Sierra Club and Montana Environmental Information Center Notice” in “Note 21 of the Notes to Consolidated Financial Statements” for further information on this matter.

Hazardous Air Pollutants (HAPs)

The EPA regulates hazardous air pollutants from a published list of industrial sources referred to as "source categories" which must meet control technology requirements if they emit one or more of the pollutants in significant quantities. In 2012, the EPA finalized the Mercury Air Toxic Standards (MATS) for the coal and oil-fired source category. For Colstrip Units 3 & 4, the only units in which we are a minority owner, the existing emission control systems should be sufficient to meet mercury limits. For the remaining portion of the rule that specifically addresses air toxics (including metals and acid gases), the Colstrip owners are currently evaluating what type of new emission control systems may be needed for MATS compliance in 2015. We continue to monitor, but are unable to determine to what extent or if there will be any material impacts to Colstrip at this time.

Regional Haze Program

The EPA set a national goal of eliminating man-made visibility degradation in Class I areas by the year 2064. States are expected to take actions to make “reasonable progress” through 10-year plans, including application of Best Available Retrofit Technology (BART) requirements. BART is a retrofit program applied to large emission sources, including electric generating units built between 1962 and 1977. In the case where a State opts out of implementing the Regional Haze program, the EPA may act directly. On September 18, 2012, the EPA finalized the Regional Haze federal implementation plan (FIP) for Montana. The FIP includes both emission limitations and pollution controls for Colstrip Units 1 & 2. Colstrip Units 3 & 4, the only units of which we are a minority owner, are not currently affected, but will be evaluated for Reasonable Progress at the next review period in September 2017. We do not anticipate any material impacts on Units 3 & 4 at this time. In November 2012, the National Parks Conservation Association, MEIC and Sierra Club filed a petition for review of EPA's Montana FIP in the U.S. Court of Appeals for the Ninth Circuit. We continue to monitor, but we are unable to predict the outcome of this matter.

Climate Change

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

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

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

Federal Legislation

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

Federal Regulatory Actions

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

GHG emission standards could result in significant compliance costs. Such standards could also preclude us from developing, operating or contracting with certain types of generating plants. Our thermal generation facilities may be impacted by the promulgated PSD permitting rules in the future. These rules can impact the time to obtain permits for new generation and major modifications to existing generating units and the final permit limitations. The promulgated and proposed GHG rulemakings mentioned above also have been legally challenged in multiple venues, so we cannot fully anticipate the outcome or extent our facilities may be impacted by these regulations at this time.

EPA Mandatory Reporting Rule (MRR)

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

State Legislation and State Regulatory Activities

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

Washington State's Department of Ecology has adopted regulations to update its State Implementation Plan relative to EPA's regulation of GHG emissions. We will continue to monitor actions by the Department as it may proceed to adopt additional regulations under its CAA authorities, and cannot predict any material impact at this time.

Washington and Oregon apply a GHG emissions performance standard (EPS) to electric generation facilities used to serve retail loads in their jurisdictions. The EPS prevents utilities from constructing or purchasing generation facilities, or entering into power purchase agreements of five years or longer duration, to purchase energy produced by plants that have emission levels higher than 1,100 pounds of GHG per MWh. The Washington State Department of Commerce (Commerce) initiated a process to adopt a lower emissions performance standard in 2012; any new standard will be applicable until at least 2017. Commerce published a supplemental notice of proposed rulemaking on January 16, 2013 with a new EPS of

970 pounds of GHG per MWh. We will continue to monitor this rulemaking, and cannot predict any material impact at this time.

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

Coal Ash Management/Disposal

Currently, coal combustion byproducts (CCBs) are not regulated by the EPA as a hazardous waste. Under a proposed rule issued in 2010, the EPA is reconsidering the classification of CCBs under the Resource Conservation and Recovery Act (RCRA). The draft rules included two options: to require management of CCBs as a hazardous waste under Subtitle C of the RCRA; or to regulate coal ash under Subtitle D, for non-hazardous solid wastes, with possible special waste requirements. Should the EPA determine to regulate CCBs as a hazardous waste under RCRA, such action could significantly impact future operations of Colstrip. Congress has also considered proposed legislation regarding CCB management. We cannot predict the impact of future CCB regulation. If we were to incur incremental costs as a result of new CCB regulations, we would seek recovery in customer rates.

Threatened and Endangered Species and Wildlife

A number of species of fish in the Northwest are listed as threatened or endangered under the Federal Endangered Species Act. Efforts to protect these and other species have not directly impacted generation levels at any of our hydroelectric facilities. We are implementing fish protection measures at its hydroelectric project on the Clark Fork River under a 45-year FERC operating license for Cabinet Gorge and Noxon Rapids (issued March 2001) that incorporates a comprehensive settlement agreement. The restoration of native salmonid fish, including bull trout, is a key part of the agreement. The result is a collaborative native salmonid restoration program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana on the lower Clark Fork River, consistent with requirements of the FERC license. The U.S. Fish & Wildlife Service issued an updated Critical Habitat Designation for bull trout in 2010 that includes the lower Clark Fork River, as well as portions of the Coeur d'Alene basin within our Spokane River Project area, and is currently developing a final Bull Trout Recovery Plan under the ESA. Issues related to these activities are expected to be resolved through the ongoing collaborative effort of our Clark Fork and Spokane River FERC licenses. See “Spokane River Licensing” and “Fish Passage at Cabinet Gorge and Noxon Rapids” in “Note 21 of the Notes to Consolidated Financial Statements” for further information.

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

Other

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

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Our primary market risk exposures are:

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

Commodity Price Risk

Electric Power Commodities

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

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

Imbalances between available power supply resources and our electric load obligations arise because of seasonal factors, operating parameters of our facilities, contract rights and contract obligations, and variations in customer demand. We forecast both obligations and resources to estimate our future surplus or deficit positions. We hedge a portion of the open position with forward transactions that establish physical supply (or disposition) and/or financially-equivalent derivatives that mitigate economic uncertainty. Seasonal factors and prevailing weather affect power supplies. Supply is affected by both temperature and the timing and amount of precipitation, particularly with respect to our hydroelectric generation facilities that rely on river flows from immediate precipitation and from melting snow. Wind conditions affect the amount and timing of supply from wind generation facilities. Operational parameters affecting power resources include natural river flow, water storage and regulation-driven constraints for hydroelectric generation. Operational parameters also include maintenance requirements and forced outages at electric generating plants, fuel availability for thermal plants, environmental and other regulatory constraints and other factors.

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

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

To balance electric power resources and electric demand obligations, we enter into transactions in the wholesale power and fuel markets. These transactions include physical power and natural gas and derivative instruments based on wholesale prices of power and natural gas. Wholesale market prices tend to vary with natural gas fuel costs to the extent that natural gas-fired resources are the least cost alternative in the region (which is often the case in recent years). Wholesale prices also tend to vary with the extent of hydroelectric surplus or shortages, particularly during the highest hydroelectric generation periods of spring rains and snow melt. Wholesale prices also vary based on wind patterns that affect output from wind generation facilities in the region. Requirements for renewable energy resources and tax credit incentives for such resources can impact wholesale prices, including sometimes pushing prices to negative values. Generating resource availability and regional demand tend to impact energy prices. Wholesale prices are quoted for energy to be delivered in time frames ranging from intra-hour, hourly, daily, multi-day, monthly, quarterly and annually. Future market prices extend several years into the future, though market liquidity tends to become limited beyond a few years into the future.

Natural Gas Commodities

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

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

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

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

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

Matters Affecting Both Electric and Natural Gas Commodities

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

When we have surplus electric generation, its value varies with market prices and economics of other resources in the region. When we have a shortage of electric generation from our own resources and other resources that we have long-term rights to control, the cost to obtain electric power or fuel varies. We make forecasts to estimate surplus and deficit conditions and we may enter into forward hedging arrangements to reduce the expected net surplus or deficit. Our forecasts cannot avoid uncertainty about loads or obligations and we do not attempt to fully hedge all forecast net open positions. Our hedges include forward transactions ranging from intra-hour to multiple years in the future, with transaction blocks of intra-hour, hourly, daily, monthly, quarterly, annually, and multiple years. See further information at “Avista Utilities - Regulatory Matters.”

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

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

- demand for electricity,
- 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,
- disruptions to or constraints on transmission facilities,
- the number of market participants and the willingness of market participants to trade, and
- weather (including temperature fluctuations and generation resulting from wind).

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

- demand for natural gas, including natural gas as fuel for electric generation,
- actual and expected changes in the North American natural gas supply volume or source mix including the growth in unconventional supplies such as natural gas from shale,
- natural gas production that can be delivered to our service areas,
- level of imports and exports, particularly from Canada by pipeline, and any taxes or restrictions that apply,
- potential development of liquefied natural gas export facilities that compete for supplies,

- level of storage inventories and regional accessibility,
- global energy markets, including oil or other natural gas substitutes, such as coal,
- availability of pipeline capacity to transport natural gas from region to region, and
- the number of market participants and the willingness of market participants to trade.

Any combination of these factors that reduces the supply of or increases demand for energy generally causes the market price to move upward. Conversely, factors that reduce demand or increase production will generally reduce market prices for energy. In addition to these factors, wholesale power markets are subject to regulatory constraints including price controls.

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

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

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2012 that are expected to settle in each respective year (dollars in thousands):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical	Financial	Physical	Financial
2013	$ (5,165)	$ (26,360)	$ (20,085)	$ (17,560)	$ 154	$ 21,423	$ (709)	$ 13,218
2014	(3,745)	(1,664)	(6,384)	(5,390)	310	6,721	(1,125)	(434)
2015	(2,890)	(273)	(1,684)	389	(136)	116	—	(227)
2016	(2,644)	—	(270)	72	(194)	—	—	—
2017	(2,293)	—	—	—	(323)	—	—	—
Thereafter	(2,396)	—	—	—	(753)	—	—	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2011 that are expected to settle in each respective year (dollars in thousands):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical	Financial	Physical	Financial
2012	$ (11,063)	$ (25,363)	$ (36,597)	$ (9,505)	$ 1,007	$ 7,206	$ 985	$ 3,647
2013	(2,479)	(12,021)	(15,112)	(12,989)	(38)	10,060	(1,073)	7,360
2014	(1,203)	(72)	(4,500)	(3,014)	(88)	1,347	(918)	(235)
2015	(1,186)	—	(1,014)	(435)	(114)	—	—	—
2016	(899)	—	(81)	46	(177)	—	—	—
Thereafter	(695)	—	—	—	(817)	—	—	—

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

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

Credit Risk

Counterparty Non-Performance Risk

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

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

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

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

We seek to mitigate bilateral credit risk by:

- entering into bilateral contracts that specify credit terms and protections against default,
- applying credit limits and duration criteria to existing and prospective counterparties,
- actively monitoring current credit exposures,
- asserting our collateral rights with counterparties, and
- carrying out transaction settlements timely and effectively.

We also mitigate credit risk by transacting through exchanges that use fully collateralized clearing arrangements to significantly reduce counterparty default risk. The extent of transactions conducted through exchanges has increased as many market participants have shown a preference toward exchange trading and have reduced bilateral transactions. We actively monitor the collateral required by such exchanges to effectively manage our capital requirements.

Our credit policy and processes 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 use both tailored and standardized agreements as we negotiate contract terms with counterparties. Such contract terms often allow for the netting or offsetting of positive and negative exposures associated with a single counterparty or affiliated group. Despite mitigation efforts, the risk of counterparty default or excessive collateral demands on us cannot be entirely eliminated.

Credit risk may be affected by industry concentration and geographic concentration. We have concentrations of suppliers and customers in the electric and natural gas industries including:

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

We have concentrations of credit risk related to our geographic location in the western United States and western Canada energy markets. 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.

Demands for Collateral

Credit risk affects demands on our capital. We are subject to limits and credit terms that counterparties may assert to allow us to enter into transactions with them and maintain acceptable credit exposures. Many of our counterparties allow unsecured credit at limits prescribed by agreements or their discretion. Capital requirements for certain transaction types involve a combination of initial margin and market value margins without any unsecured credit threshold. Counterparties may seek assurances of performance from us in the form of letters of credit, prepayment or cash deposits.

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

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

Risk Management for Energy Resources

We have an energy resources risk policy, which includes our wholesale energy markets credit policy and control procedures to manage energy commodity price and credit risks. Our Risk Management Committee established our risk management policy for energy resources. The Risk Management Committee is comprised of certain officers and other management. Our Risk Management Committee also established our 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.

The Audit Committee of the Company's Board of Directors periodically reviews and discusses enterprise risk management processes, and it focuses on the Company's material financial and accounting risk exposures and the steps management has undertaken to control them. Our Risk Management Committee reviews the status of risk exposures through regular reports and meetings. Nonetheless, adverse changes in commodity prices, generating capacity, customer loads, regulation and other factors may result in losses of earnings, cash flows and/or fair values.

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

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

Our projected retail 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 mitigates potential adverse impacts of significant purchase requirements in a volatile price environment.

Interest Rate Risk

We are affected by fluctuating interest rates related to a portion of our existing debt, our future borrowing requirements, and our pension and other post-retirement benefit obligations. The Finance Committee of our Board of Directors periodically reviews and discusses interest rate risk management processes, and it focuses on the steps management has undertaken to control it. We manage interest rate exposure by limiting our variable rate exposures to a percentage of total capitalization. Additionally, interest rate risk is managed by monitoring market conditions when timing the issuance of long-term debt and optional debt redemptions and through the use of fixed rate long-term debt with varying maturities. We also hedge a portion of our interest rate risk with financial derivative instruments, which may include interest rate swaps and U.S. Treasury lock agreements.

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

As of December 31, 2012, we had interest rate swap agreements with a total notional amount of $160.0 million with mandatory cash settlement dates of June 2013, October 2014, and October 2015 (which we entered into in September 2011 and June 2012).

As of December 31, 2012, we had a current derivative liability of $1.4 million and a long-term derivative asset of $7.3 million, with an offsetting regulatory asset and liability on the Consolidated Balance Sheets in accordance with regulatory accounting practices. We estimate that a 10-basis-point increase in forward LIBOR interest rates as of December 31, 2012 would increase the interest rate swap derivative net asset by $3.3 million, while a 10-basis-point decrease would decrease the interest rate swap net asset by $3.3 million.

As of December 31, 2011, we had interest rate swap agreements with a total notional amount of $160.0 million and a total derivative liability of $18.9 million. We estimated that a 10-basis-point increase in forward LIBOR interest rates as of December 31, 2011 would have increased this derivative liability by $3.4 million, while a 10-basis-point decrease would decrease the liability by $3.4 million.

In May 2012, we cash settled interest rate swap contracts (notional amount of $75.0 million) and paid a total of $18.5 million. The interest rate swap contracts were settled in connection with the pricing of $80.0 million of First Mortgage Bonds. Upon settlement of the interest rate swaps, the regulatory asset or liability (included as part of long-term debt) will be amortized as a component of interest expense over the life of the forecasted interest payments.

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

The following table shows our long-term debt (including current portion) and related weighted average interest rates, by expected maturity dates as of December 31, 2012 (dollars in thousands):

	2013	2014	2015	2016	2017	Thereafter	Total	Fair Value
Fixed rate long-term debt	$ 50,000	—	—	—	—	$ 1,203,000	$ 1,253,000	$ 1,485,531
Weighted average interest rate	1.68%	—	—	—	—	5.48%	5.33%	
Fixed rate nonrecourse long-term debt of Spokane Energy	$ 14,965	$ 16,407	$ 1,431	—	—	—	$ 32,803	$ 35,297
Weighted average interest rate	8.45%	8.45%	8.45%	—	—	—	8.45%	
Variable rate long-term debt to affiliated trusts	—	—	—	—	—	$ 51,547	$ 51,547	$ 43,686
Weighted average interest rate	—	—	—	—	—	1.19%	1.19%	

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. The short-term natural gas transactions are typically settled within sixty days with U.S. dollars. We economically hedge a portion of the foreign currency risk by purchasing Canadian currency when such commodity transactions are initiated. This risk has not had a material effect on our financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations are included with natural gas supply costs for ratemaking. As of December 31, 2012, 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, 2012, we had entered into 20 Canadian currency forward contracts with a notional amount of $12.6 million ($12.5 million Canadian). As of December 31, 2011, we had entered into 28 Canadian currency forward contracts with a notional amount of $7.0 million ($7.2 million Canadian) with current derivative asset of less than $0.1 million.

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

Item 8. Financial Statements and Supplementary Data

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for each of the three years in the period ended December 31, 2012. 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 3 to the consolidated financial statements, the Company changed its method of accounting for variable interest entities effective January 1, 2010, due to the adoption of Accounting Standards Update No. 2009-17, *Consolidations - Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities*.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, 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, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 26, 2013

CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

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

	2012	2011	2010
Operating Revenues:			
Utility revenues	$ 1,352,385	$ 1,441,522	$ 1,417,846
Ecova revenues	155,664	137,848	102,035
Other non-utility revenues	38,953	40,410	38,859
Total operating revenues	1,547,002	1,619,780	1,558,740
Operating Expenses:			
Utility operating expenses:			
Resource costs	693,127	790,048	795,075
Other operating expenses	276,780	261,926	252,437
Depreciation and amortization	112,091	105,629	100,554
Taxes other than income taxes	83,409	83,347	73,382
Ecova operating expenses:			
Other operating expenses	139,173	109,738	80,100
Depreciation and amortization	13,519	7,193	6,070
Other non-utility operating expenses:			
Other operating expenses	38,041	33,117	30,386
Depreciation and amortization	792	778	1,002
Total operating expenses	1,356,932	1,391,776	1,339,006
Income from operations	190,070	228,004	219,734
Interest expense	76,894	73,876	75,789
Interest expense to affiliated trusts	541	332	635
Capitalized interest	(2,401)	(2,942)	(298)
Other income-net	(5,025)	(3,433)	(2,497)
Income before income taxes	120,061	160,171	146,105
Income tax expense	41,261	56,632	51,157
Net income	78,800	103,539	94,948
Less: Net income attributable to noncontrolling interests	(590)	(3,315)	(2,523)
Net income attributable to Avista Corporation shareholders	$ 78,210	$ 100,224	$ 92,425
Weighted-average common shares outstanding (thousands), basic	59,028	57,872	55,595
Weighted-average common shares outstanding (thousands), diluted	59,201	58,092	55,824
Earnings per common share attributable to Avista Corporation shareholders:			
Basic	$ 1.32	$ 1.73	$ 1.66
Diluted	$ 1.32	$ 1.72	$ 1.65
Dividends paid per common share	$ 1.16	$ 1.10	$ 1.00

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

	2012	2011	2010
Net income	$ 78,800	$ 103,539	$ 94,948
Other Comprehensive Income (Loss):			
Unrealized investment gains - net of taxes of $191 and $77, respectively	323	134	—
Reclassification adjustment for realized gains on investment securities included in net income - net of taxes of $(171)	(290)	—	—
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $(590), $(778) and $(1,064), respectively	(1,096)	(1,445)	(1,976)
Total other comprehensive loss	(1,063)	(1,311)	(1,976)
Comprehensive income	77,737	102,228	92,972
Comprehensive income attributable to noncontrolling interests	(590)	(3,315)	(2,523)
Comprehensive income attributable to Avista Corporation shareholders	$ 77,147	$ 98,913	$ 90,449

The Accompanying Notes are an Integral Part of These Statements.

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CONSOLIDATED BALANCE SHEETS

Avista Corporation

As of December 31
Dollars in thousands

	2012	2011
Assets:		
Current Assets:		
Cash and cash equivalents	$ 75,464	$ 74,662
Accounts and notes receivable-less allowances of $44,155 and $43,958	193,683	203,452
Utility energy commodity derivative assets	4,139	1,139
Regulatory asset for utility derivatives	35,082	69,685
Investments and funds held for clients	88,272	118,536
Materials and supplies, fuel stock and natural gas stored	47,455	52,006
Deferred income taxes	34,281	30,473
Income taxes receivable	2,777	15,378
Other current assets	24,641	49,225
Total current assets	505,794	614,556
Net Utility Property:		
Utility plant in service	4,054,644	3,887,384
Construction work in progress	143,098	79,322
Total	4,197,742	3,966,706
Less: Accumulated depreciation and amortization	1,174,026	1,105,930
Total net utility property	3,023,716	2,860,776
Other Non-current Assets:		
Investment in exchange power-net	16,333	18,783
Investment in affiliated trusts	11,547	11,547
Goodwill	75,959	39,045
Intangible assets-net of accumulated amortization of $26,030 and $16,629, respectively	46,256	34,622
Long-term energy contract receivable of Spokane Energy	52,033	62,525
Other property and investments-net	46,542	45,687
Total other non-current assets	248,670	212,209
Deferred Charges:		
Regulatory assets for deferred income tax	79,406	84,576
Regulatory assets for pensions and other postretirement benefits	306,408	260,359
Other regulatory assets	103,946	119,738
Non-current utility energy commodity derivative assets	1,093	185
Non-current regulatory asset for utility derivatives	25,218	40,345
Other deferred charges	18,928	21,787
Total deferred charges	534,999	526,990
Total assets	$ 4,313,179	$ 4,214,531

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

As of December 31

Dollars in thousands

	2012	2011
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 198,914	$ 166,954
Client fund obligations	87,839	118,325
Current portion of long-term debt	50,372	7,474
Current portion of nonrecourse long-term debt of Spokane Energy	14,965	13,668
Short-term borrowings	52,000	96,000
Utility energy commodity derivative liabilities	29,515	70,824
Other current liabilities	142,544	153,929
Total current liabilities	576,149	627,174
Long-term debt	1,178,367	1,169,826
Nonrecourse long-term debt of Spokane Energy	17,838	32,803
Long-term debt to affiliated trusts	51,547	51,547
Long-term borrowings under committed line of credit	54,000	—
Regulatory liability for utility plant retirement costs	234,128	227,282
Pensions and other postretirement benefits	283,985	246,177
Deferred income taxes	524,877	505,954
Other non-current liabilities and deferred credits	110,215	116,084
Total liabilities	3,031,106	2,976,847
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Redeemable Noncontrolling Interests	4,938	51,809
Equity:		
Avista Corporation Stockholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 59,812,796 and 58,422,781 shares outstanding	889,237	855,188
Accumulated other comprehensive loss	(6,700)	(5,637)
Retained earnings	376,940	336,150
Total Avista Corporation stockholders' equity	1,259,477	1,185,701
Noncontrolling Interests	17,658	174
Total equity	1,277,135	1,185,875
Total liabilities and equity	$ 4,313,179	$ 4,214,531

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

	2012	2011	2010
Operating Activities:			
Net income	$ 78,800	$ 103,539	$ 94,948
Non-cash items included in net income:			
Depreciation and amortization	126,402	113,600	107,626
Provision for deferred income taxes	21,449	24,007	37,734
Power and natural gas cost amortizations (deferrals), net	6,702	21,870	(9,795)
Amortization of debt expense	3,803	4,617	4,414
Amortization of investment in exchange power	2,450	2,450	2,450
Stock-based compensation expense	5,792	5,756	4,916
Equity-related AFUDC	(4,055)	(2,225)	(3,353)
Pension and other postretirement benefit expense	39,838	32,067	24,760
Amortization of Spokane Energy contract	10,492	9,645	8,866
Other	5,256	(4,988)	(2,365)
Contributions to defined benefit pension plan	(44,000)	(26,000)	(21,000)
Changes in working capital components:			
Accounts and notes receivable	8,100	30,616	(19,081)
Materials and supplies, fuel stock and natural gas stored	4,551	(3,388)	(11,248)
Other current assets	27,258	(23,881)	(9,230)
Accounts payable	30,189	(18,032)	13,606
Other current liabilities	(6,474)	(188)	5,189
Net cash provided by operating activities	316,553	269,465	228,437
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(271,187)	(239,782)	(202,227)
Other capital expenditures	(4,787)	(3,590)	(2,429)
Federal grant payments received	8,277	16,928	7,585
Cash paid by subsidiaries for acquisitions, net of cash received	(50,310)	(31,409)	(3,777)
Decrease (increase) in funds held for clients	(6,811)	78,561	(48,895)
Purchase of securities available for sale	(100,374)	(96,634)	—
Sale and maturity of securities available for sale	137,999	80	—
Other	(7,475)	(6,435)	(3,480)
Net cash used in investing activities	(294,668)	(282,281)	(253,223)

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

	2012	2011	2010
Financing Activities:			
Net increase (decrease) in short-term borrowings	$ (9,000)	$ (49,000)	$ 23,000
Borrowings from Ecova line of credit	33,000	35,000	2,300
Repayment of borrowings from Ecova line of credit	(14,000)	—	(8,000)
Proceeds from issuance of long-term debt	80,000	85,000	136,365
Redemption and maturity of long-term debt	(11,492)	(297)	(110,242)
Premiums paid for the redemption of long-term debt	—	—	(10,710)
Maturity of nonrecourse long-term debt of Spokane Energy	(13,669)	(12,463)	(11,370)
Long-term debt and short-term borrowing issuance costs	(764)	(4,477)	(916)
Cash paid for settlement of interest rate swap agreements	(18,547)	(10,557)	—
Issuance of common stock	29,079	26,463	46,235
Cash dividends paid	(68,552)	(63,737)	(55,682)
Purchase of subsidiary noncontrolling interest	(917)	(6,179)	(2,593)
Increase (decrease) in client fund obligations	(30,996)	17,782	48,895
Issuance of subsidiary noncontrolling interest	3,714	—	—
Other	1,061	530	(118)
Net cash provided by (used in) financing activities	(21,083)	18,065	57,164
Net increase in cash and cash equivalents	802	5,249	32,378
Cash and cash equivalents at beginning of year	74,662	69,413	37,035
Cash and cash equivalents at end of year	$ 75,464	$ 74,662	$ 69,413
Supplemental Cash Flow Information:			
Cash paid during the year:			
Interest	$ 74,900	$ 69,083	$ 74,195
Income taxes	8,069	26,451	14,153
Non-cash financing and investing activities:			
Accounts payable for capital expenditures	21,331	20,629	8,315
Utility property acquired under capital leases	—	—	5,300
Redeemable noncontrolling interests	(10,104)	4,059	10,442
Contingent consideration by subsidiary for acquisition	375	—	1,134

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS

Avista Corporation

For the Years Ended December 31

Dollars in thousands

	2012	2011	2010
Common Stock, Shares:			
Shares outstanding at beginning of year	58,422,781	57,119,723	54,836,781
Issuance of common stock through equity compensation plans	245,661	275,057	141,645
Issuance of common stock through Employee Investment Plan (401-K)	45,715	43,179	11,116
Issuance of common stock through Dividend Reinvestment Plan	167,448	177,822	76,071
Issuance of common stock	931,191	807,000	2,054,110
Shares outstanding at end of year	59,812,796	58,422,781	57,119,723
Common Stock, Amount:			
Balance at beginning of year	$ 855,188	$ 827,592	$ 778,647
Equity compensation expense	5,716	3,635	3,097
Issuance of common stock through equity compensation plans	305	1,879	1,942
Issuance of common stock through Employee Investment Plan (401-K)	1,165	1,073	235
Issuance of common stock through Dividend Reinvestment Plan	4,226	4,299	1,451
Issuance of common stock, net of issuance costs	23,383	19,213	42,607
Equity transactions of consolidated subsidiaries	(746)	(2,503)	(387)
Balance at end of year	889,237	855,188	827,592
Accumulated Other Comprehensive Loss:			
Balance at beginning of year	(5,637)	(4,326)	(2,350)
Other comprehensive loss	(1,063)	(1,311)	(1,976)
Balance at end of year	(6,700)	(5,637)	(4,326)
Retained Earnings:			
Balance at beginning of year	336,150	302,518	274,990
Net income attributable to Avista Corporation shareholders	78,210	100,224	92,425
Cash dividends paid (common stock)	(68,552)	(63,737)	(55,682)
Expiration of subsidiary noncontrolling interests redemption rights	23,805	—	—
Valuation adjustments and other noncontrolling interests activity	7,327	(2,855)	(9,215)
Balance at end of year	376,940	336,150	302,518
Total Avista Corporation stockholders' equity	1,259,477	1,185,701	1,125,784
Noncontrolling Interests:			
Balance at beginning of year	174	(600)	(673)
Net income attributable to noncontrolling interests	451	756	66
Deconsolidation of variable interest entity	(673)	—	—
Purchase of subsidiary noncontrolling interests	(117)	—	—
Expiration of subsidiary noncontrolling interests redemption rights	17,790	—	—
Other	33	18	7
Balance at end of year	17,658	174	(600)
Total equity	$ 1,277,135	$ 1,185,875	$ 1,125,184
Redeemable Noncontrolling Interests:			
Balance at beginning of year	$ 51,809	$ 46,722	$ 34,833
Net income attributable to noncontrolling interests	139	2,559	2,457
Issuance of subsidiary noncontrolling interests	3,714	—	—
Purchase of subsidiary noncontrolling interests	(784)	(6,179)	(2,593)
Expiration of subsidiary noncontrolling interests redemption rights	(41,595)	—	—
Valuation adjustments and other noncontrolling interests activity	(8,345)	8,707	12,025
Balance at end of year	$ 4,938	$ 51,809	$ 46,722

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 northeastern and southwestern Oregon. Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility businesses, except Spokane Energy, LLC (Spokane Energy). Avista Capital's subsidiaries include Ecova, Inc. (Ecova), a 79.0 percent owned subsidiary as of December 31, 2012. Ecova is a provider of energy efficiency and other facility information and cost management programs and services for multi-site customers and utilities throughout North America. See Note 24 for business segment information.

Basis of Reporting

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries, including Ecova and other majority owned subsidiaries and variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Intercompany balances were eliminated in consolidation. The accompanying consolidated financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (see Note 7).

Use of Estimates

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

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

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

System of Accounts

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

Regulation

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

Utility Revenues

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

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

	2012	2011
Unbilled accounts receivable	$ 77,298	$ 82,950

Ecova Revenues

Service revenues from Ecova are recognized over the period services are rendered, which is typically on a straight-line basis for fixed-fee or project-fee engagements or ratably for other types of services. New client account setup fees and implementation (onboarding) fees are deferred and recognized over the contractual life that approximates the expected customer relationship, which is typically the contract period. Investment earnings on funds held for clients and fees earned from third parties on payment processing are an integral part of Ecova's product offerings and are recognized in revenues as earned. Revenue arrangements with multiple elements occur infrequently and generally represent a very small percentage of total Ecova revenues. When they occur, the separate deliverables are divided into separate units of accounting if certain criteria are met, and the total consideration received is allocated among the different deliverables using the relative selling price method. In most cases, management uses its best estimate of the selling price for each deliverable to determine the amount of consideration to allocate and revenue is recognized for each deliverable once all the applicable revenue recognition criteria are met. In the Consolidated Statements of Income, the full amount of Ecova revenues are recorded in operating revenues (inclusive of the noncontrolling interest portion), but then the noncontrolling interest share (currently 21.0 percent) is backed out in the "Net income attributable to noncontrolling interests" line on the Consolidated Statements of Income.

Other Non-Utility Revenues

Revenues from the other businesses derived from the operations of Advanced Manufacturing and Development (doing business as METALfx) and are recognized when the risk of loss transfers to the customer, which occurs when products are shipped.

Advertising Expenses

The Company expenses advertising costs as incurred. Advertising expenses were not a material portion of the Company's operating expenses in 2012, 2011 and 2010.

Depreciation

For utility operations, depreciation expense is estimated by a method of depreciation accounting utilizing composite rates for utility plant. Such rates are designed to provide for retirements of properties at the expiration of their service lives. For utility operations, the ratio of depreciation provisions to average depreciable property was as follows for the years ended December 31:

	2012	2011	2010
Ratio of depreciation to average depreciable property	2.92%	2.92%	2.84%

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

- electric thermal production - 33 years,
- hydroelectric production - 73 years,
- electric transmission - 51 years,
- electric distribution - 38 years, and
- natural gas distribution property - 49 years.

Taxes Other Than Income Taxes

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

	2012	2011	2010
Utility taxes	$ 53,716	$ 55,739	$ 49,953

Allowance for Funds Used During Construction

The Allowance for Funds Used During Construction (AFUDC) represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. As prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant and the debt related portion is credited against total interest expense in the Consolidated Statements of Income in the line item “capitalized interest.” The equity related portion of AFUDC is included in the Consolidated Statement of Income in the line item “other expense (income)-net.” The Company is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a reasonable return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant is placed in service. Cash inflow related to AFUDC does not occur until the related utility plant is placed in service and included in rate base. The effective AFUDC rate was the following for the years ended December 31:

	2012	2011	2010
Effective AFUDC rate	7.62%	7.91%	8.25% (1)

(1) Generally, the AFUDC rate changes effective January 1 of every year, however this rate was effective from January 1, 2010 to November 30, 2010. Effective December 1, 2010, the rate was changed to 7.91%.

Income Taxes

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

Stock-Based Compensation

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

Other Income - Net

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

	2012	2011	2010
Interest income	$ (944)	$ (1,327)	$ (1,159)
Interest on regulatory deferrals	(68)	(89)	(248)
Equity-related AFUDC	(4,055)	(2,225)	(3,353)
Net loss on investments	3,343	488	3,297
Other income	(3,301)	(280)	(1,034)
Total (1)	$ (5,025)	$ (3,433)	$ (2,497)

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

Earnings per Common Share Attributable to Avista Corporation Shareholders

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

Cash and Cash Equivalents

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

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):

	2012	2011	2010
Allowance as of the beginning of the year	$ 43,958	$ 44,883	$ 42,928
Additions expensed during the year	4,213	5,232	5,194
Net deductions	(4,016)	(6,157)	(3,239)
Allowance as of the end of the year	$ 44,155	$ 43,958	$ 44,883

Materials and Supplies, Fuel Stock and Natural Gas Stored

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

	2012	2011
Materials and supplies	$ 26,058	$ 24,148
Fuel stock	4,121	4,248
Natural gas stored	17,276	23,610
Total	$ 47,455	$ 52,006

Investments and Funds Held for Clients and Client Fund Obligations

In connection with the bill paying services, Ecova collects funds from its clients and remits the funds to the appropriate utility or other service provider. Some of the funds collected are invested by Ecova and classified as investments and funds held for clients and a related liability for client fund obligations is recorded. Investments and funds held for clients include cash and cash equivalent investments, money market funds and investment securities classified as available for sale. Investments and funds held for clients as of December 31, 2012 are as follows (dollars in thousands):

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

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

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

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

Investments and funds held for clients are classified as a current asset since these funds are held for the purpose of satisfying the client fund obligations. Approximately 97 percent and 88 percent of the investment portfolio is rated AA or higher as of December 31, 2012 and 2011, respectively, by nationally recognized statistical rating organizations. All fixed income securities were rated as investment grade as of December 31, 2012 and 2011.

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

Proceeds from sales, maturities and calls of securities available for sale were $138.0 million and $0.1 million, for the years ended December 31, 2012 and 2011, respectively. Gross realized gains were $0.5 million for the year ended December 31, 2012 and were negligible for the year ended December 31, 2011. There were not any gross realized losses during these periods.

Contractual maturities of securities available for sale as of December 31, 2012 and 2011 are as follows (dollars in thousands):

Maturity date	Due within 1 year	After 1 but within 5 years	After 5 but within 10 years	After 10 years	Total
December 31, 2012	$ 3,047	$ 11,786	$ 41,485	$ 3,003	$ 59,321
December 31, 2011	425	55,126	41,028	—	96,579

Actual maturities may differ due to call or prepayment rights and the effective maturity was 1.9 years as of December 31, 2012 and 1.3 years as of December 31, 2011.

Utility Plant in Service

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

Asset Retirement Obligations

The Company recovers certain asset retirement costs through rates charged to customers as a portion of its depreciation expense for which the Company has not recorded asset retirement obligations (see Note 9). The Company had estimated retirement costs (that do not represent legal or contractual obligations) included as a regulatory liability on the Consolidated Balance Sheets of the following amounts as of December 31 (dollars in thousands):

	2012	2011
Regulatory liability for utility plant retirement costs	$ 234,128	$ 227,282

Goodwill

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

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

	Ecova	Other	Accumulated Impairment Losses	Total
Balance as of January 1, 2011	$ 20,689	$ 12,979	$ (7,733)	$ 25,935
Goodwill acquired during the year	12,933	—	—	12,933
Adjustments	177	—	—	177
Balance as of the December 31, 2011	33,799	12,979	(7,733)	39,045
Goodwill acquired during the year	33,484	—	—	33,484
Adjustments	3,430	—	—	3,430
Balance as of the December 31, 2012	$ 70,713	$ 12,979	$ (7,733)	$ 75,959

Accumulated impairment losses are attributable to the other businesses. The goodwill acquired in 2011 was related to Ecova’s acquisition of Prenova, Inc. (Prenova) on November 30, 2011. The goodwill acquired in 2012 was related to Ecova's acquisition of LPB Energy Management (LPB) effective January 31, 2012. The adjustment to goodwill recorded represents purchase accounting adjustments for Ecova's acquisition of Prenova based upon final review of the fair market values of relevant assets and liabilities identified as of the acquisition date. The primary cause of the revisions was due to a net operating loss study and a change in the value of customer relationships. Final purchase accounting related to LPB is pending the completion of further review of the fair market value of the noncontrolling interests associated with a portion of the LPB business and this will be completed during 2013.

Intangible Assets

Intangible assets primarily represent the amounts assigned to client relationships related to the Ecova acquisition of Cadence Network in 2008 (estimated amortization period of 12 years), Ecos in 2009 (estimated amortization period of 3 years), Loyalton in 2010 (estimated amortization period of 6 years), Prenova in 2011 (estimated amortization period of 9 years) and LPB in 2012 (estimated amortization period of 10 years), software development costs (estimated amortization period of 3 to 4 years) and other. Adjustments to acquired intangible assets associated with Prenova based on final review of the fair market values include decreases of $0.4 million to the customer relationships intangible, $2.1 million to the internal use software intangible, and $0.8 million to other intangibles.

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

	2012	2011	2010
Intangible asset amortization	$ 10,435	$ 4,682	$ 3,755

The following table details the estimated amortization expense for the next five years related to Intangible Assets (dollars in thousands):

	2013	2014	2015	2016	2017
Estimated amortization expense	$ 9,893	$ 9,621	$ 7,238	$ 6,116	$ 5,222

The gross carrying amount and accumulated amortization of Intangible Assets as of December 31, 2012 and 2011 are as follows (dollars in thousands):

	2012	2011
Client relationships	$ 32,059	$ 18,859
Software development costs	33,990	29,327
Other	6,237	3,065
Total intangible assets	72,286	51,251
Client relationships accumulated amortization	(7,793)	(3,623)
Software development costs accumulated amortization	(16,557)	(12,016)
Other accumulated amortization	(1,680)	(990)
Total accumulated amortization	(26,030)	(16,629)
Total intangible assets - net	$ 46,256	$ 34,622

Of the total net intangible assets above, intangible assets associated with Ecova represent approximately $45.4 million and $33.6 million at December 31, 2012 and December 31, 2011, respectively.

Derivative Assets and Liabilities

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

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

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

Fair Value Measurements

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

Regulatory Deferred Charges and Credits

The Company prepares its consolidated financial statements in accordance with regulatory accounting practices because:

- rates for regulated services are established by or subject to approval by independent third-party regulators,
- the regulated rates are designed to recover the cost of providing the regulated services, and
- in view of demand for the regulated services and the level of competition, it is reasonable to assume that rates can be charged to and collected from customers at levels that will recover costs.

Regulatory accounting practices require that certain costs and/or obligations (such as incurred power and natural gas costs not currently included in rates, but expected to be recovered or refunded in the future) are reflected as deferred charges or credits on the Consolidated Balance Sheets. These costs and/or obligations are not reflected in the Consolidated Statements of Income until the period during which matching revenues are recognized. If at some point in the future the Company determines that it no longer meets the criteria for continued application of regulatory accounting practices for all or a portion of its regulated operations, the Company could be:

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

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

Investment in Exchange Power-Net

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

Unamortized Debt Expense

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

Unamortized Debt Repurchase Costs

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

Redeemable Noncontrolling Interests

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

Accumulated Other Comprehensive Loss

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

	2012	2011
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $(3,698) and $(3,107), respectively	$ (6,867)	$ (5,771)
Unrealized gain on securities available for sale - net of taxes of $99 and $79, respectively	167	134
Total accumulated other comprehensive loss	$ (6,700)	$ (5,637)

Contingencies

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

Immaterial Correction of an Error

Subsequent to the issuance of the Company's 2011 consolidated financial statements, the Company's management identified certain employee-related operating expenses, dues and donations, and other operating expenses totaling $7.6 million and $10.5 million in 2011 and 2010, respectively, which had been erroneously included in "Other expense-net" in the previously issued financial statements rather than as a reduction to "Income from operations". Accordingly, such classification has been corrected in the accompanying 2011 and 2010 consolidated statements of income by including these costs within "other" operating expenses. The restated items are also reflected in the information presented in Note 24, Information by Business Segments and Note 25, Selected Quarterly Financial Data (Unaudited). Such items had no effect on net income or earnings per share.

Reclassifications

Certain prior year amounts on the Company's Consolidated Statements of Income, Consolidated Balance Sheets, and Consolidated Statements of Cash Flows have been reclassified to conform to the current year presentation. In the current year Consolidated Statements of Income, Ecova operating revenues and operating expenses have been reclassified to separate line items. Previously, such amounts had been classified within the line items captioned "Other non-utility revenues" and “Other non-utility operating expenses”, respectively. Also, see Note 1, “Other Income-Net” concerning a corrective reclassification made to certain 2011 and 2010 operating expenses. In the current year Consolidated Balance Sheets, "Intangible assets" are presented as their own line item. These were previously included in "Other intangibles, property and investments, net", which has now been renamed to "Other property and investments, net". In the current year Consolidated Statements of Cash Flows, "Pension and other postretirement benefit expense" and "Amortization of Spokane Energy contract" have been added as their own line items. These were previously included in "Other" in the operating activities section. Also, "Payments for settlements with Coeur d'Alene Tribe" was previously included as its own line item in operating activities. This has how been included in "Other" in the operating activities section.

NOTE 2. NEW ACCOUNTING STANDARDS

Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) No. 2011-04, “Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs.” This ASU requires enhanced disclosures for fair value measurements, including quantitative analysis of unobservable inputs used in Level 3 fair value measurements. The ASU also clarifies the FASB's intent about the application of existing fair value measurement requirements. The adoption of this ASU did not have any impact on the Company's financial condition, results of operations and cash flows. See Note 17 for the Company's fair value disclosures.

In February 2013, the FASB issued ASU No. 2013-02, “Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income.” This ASU does not change current requirements for reporting net income or other comprehensive income in financial statements; however, it will require entities to disclose the effect on the line items of net income for reclassifications out of accumulated other comprehensive income if the item being reclassified is required to be reclassified in its entirety to net income under U.S. GAAP. For other items that are not required to be reclassified in their entirety to net income under U.S. GAAP, an entity is required to cross-reference other disclosures required under U.S. GAAP to provide additional detail about those items. This ASU is effective for fiscal years beginning after December 15, 2012. The Company does not expect that this ASU will have any material impact on its financial condition, results of operations and cash flows.

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

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

NOTE 3. VARIABLE INTEREST ENTITIES

Lancaster Power Purchase Agreement

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

Avista Corp. has a variable interest in the PPA. Accordingly, Avista Corp. made an evaluation of which interest holders have the power to direct the activities that most significantly impact the economic performance of the entity and which interest holders have the obligation to absorb losses or receive benefits that could be significant to the entity. Avista Corp. pays a fixed capacity and operations and maintenance payment and certain monthly variable costs under the PPA. Under the terms of the PPA, Avista Corp. makes the dispatch decisions, provides all natural gas fuel and receives all of the electric energy output from the Lancaster Plant. However, Rathdrum Power LLC (the owner) controls the daily operation of the Lancaster Plant and makes operating and maintenance decisions. Rathdrum Power LLC controls all of the rights and obligations of the Lancaster Plant after the expiration of the PPA in 2026. It is estimated that the plant will have 15 to 25 years of useful life after that time. Rathdrum Power LLC bears the maintenance risk of the plant and will receive the residual value of the Lancaster Plant. Avista Corp. has no debt or equity investments in the Lancaster Plant and does not provide financial support through liquidity arrangements or other commitments (other than the PPA). Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Lancaster Plant. Accordingly, neither the Lancaster Plant nor Rathdrum Power LLC is included in Avista Corp.'s consolidated financial statements. The Company has a future contractual obligation of approximately $320 million under the PPA (representing the fixed capacity and operations and maintenance payments through 2026) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

Palouse Wind Power Purchase Agreement

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

The Company evaluated this agreement to determine if it has a variable interest which must be consolidated. Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Palouse Wind facility due to the fact that it pays a fixed price per MWh, which represents the only financial obligation, and does not have any input into the management of the day-to-day operations of the facility. Accordingly, Palouse Wind is not included in Avista Corp.'s consolidated financial statements. The Company has a future contractual obligation of approximately $576 million under the PPA (representing the charges associated with purchasing the energy and renewable attributes through 2042) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

Spokane Energy

The implementation of amendments to ASC 810 resulted in the Company including Spokane Energy, LLC (Spokane Energy) in its consolidated financial statements effective January 1, 2010. Spokane Energy is a special purpose limited liability company and all of its membership capital is owned by Avista Corp. Spokane Energy was formed in December 1998 to assume ownership of a fixed rate electric capacity contract between Avista Corp. and Portland General Electric Company.

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

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

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

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

NOTE 4. VOLUNTARY SEVERANCE INCENTIVE PROGRAM

On October 22, 2012, Avista Corp. announced a voluntary severance incentive program to reduce the total utility workforce and achieve necessary long-term, sustainable, Company-wide savings, in addition to other cost saving measures.

In general, most regular full and part-time employees of Avista Corp. (not including any of its subsidiaries) who were not covered by a collective bargaining agreement were eligible to participate in the program. Based on the response to the program by interested employees and the approvals by Company management, the program resulted in the termination of 55, or approximately 6 percent, of the eligible 919 non-union employees, and the total severance costs under the program were $7.3 million (pre-tax). The total severance costs are made up of the severance payments and the related payroll taxes and employee benefit costs. Approximately 50 percent of the applicants to the program were approved for termination by Company management. The long-term operating and maintenance cost savings under the program are expected to exceed the severance costs of the program and the expected payback period for the severance costs will be approximately 1.4 years.

Each participant in the program was entitled to receive severance pay in an amount calculated by reference to the participant's years of service and base pay as of December 31, 2012. In no event did the amount of severance pay exceed 78 weeks of a participant's base pay.

All terminations under the voluntary severance incentive program were completed by December 31, 2012. The cost of the program was recognized as expense during the fourth quarter of 2012 and severance pay was distributed in a single lump sum cash payment to each participant during January 2013.

NOTE 5. REDEEMABLE NONCONTROLLING INTERESTS AND SUBSIDIARY ACQUISITIONS

The acquisition of Cadence Network in July 2008 was funded by issuing additional Ecova common stock. Under the transaction agreement, the previous owners of Cadence Network had a right to have their shares of Ecova common stock redeemed by Ecova during July 2011 or July 2012 if their investment in Ecova was not liquidated through either an initial public offering or sale of the business to a third party. These redemption rights were not exercised and expired effective July 31, 2012. As such, this redeemable noncontrolling interest was reclassified to equity effective July 31, 2012. Additionally, certain minority shareholders and option holders of Ecova have the right to put their shares back to Ecova at their discretion during an annual put window. Stock options and other outstanding redeemable stock are valued at their maximum redemption amount which is equal to their intrinsic value (fair value less exercise price) (see Note 20 for further information).

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

	2012	2011
Previous owners of Cadence Network	$ —	$ 38,893
Stock options and other outstanding redeemable stock	4,938	12,916
Total redeemable noncontrolling interests	$ 4,938	$ 51,809

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

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

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

On November 30, 2011, Ecova acquired all of the capital stock of Prenova, Inc. (Prenova), an Atlanta-based energy management company. The cash paid for the acquisition of Prenova of $35.7 million was funded primarily through borrowings under Ecova's committed credit agreement. The acquired assets and assumed liabilities of Prenova were recorded at their respective estimated fair values as of the date of acquisition. Assets recorded include the following (inclusive of purchase accounting adjustments recorded during 2012): accounts receivable of $2.6 million, deferred income tax assets of $3.1 million, goodwill of $16.6 million, client relationships of $7.0 million (estimated amortization period of 9 years) and internal use software of $3.3 million (estimated amortization period of 5 years). These intangible assets are included in intangible assets on the Consolidated Balance Sheet. The results of operations of Prenova are included in the consolidated financial statements beginning December 1, 2011.

On January 31, 2012, Ecova acquired all of the capital stock of LPB Energy Management (LPB), a Dallas, Texas-based energy management company. The cash paid for the acquisition of LPB of $50.6 million was funded by Ecova through $25.0 million of borrowings under its committed credit agreement, a $20.0 million equity infusion from existing shareholders (including Avista Capital and the other owners of Ecova), and available cash. The acquired assets and assumed liabilities of LPB were recorded at their respective estimated fair values as of the date of acquisition. Assets recorded include the following: accounts receivable of $2.5 million, goodwill of $33.2 million, client backlog of $8.2 million (estimated amortization period of 3 years), client relationships of $4.8 million (estimated amortization period of 10 years) and internal use software of $2.5 million (estimated amortization period of 3 to 4 years). These intangible assets are included in intangible assets on the Consolidated Balance Sheet. Included in the goodwill amount is $1.1 million attributable to assembled workforce that is deductible and will be amortized for tax purposes over a 15-year period and is subject to impairment review annually. The results of operations of LPB are included in the consolidated financial statements beginning February 1, 2012. The sellers of LPB did not receive additional purchase price payments in 2012; however, they have the potential to receive additional purchase price payments of $1.0 million in 2013 and $1.5 million in 2014. These payments are contingent upon reaching certain revenue thresholds for certain customer contracts. As of December 31, 2012, Ecova has recorded a contingent liability of $0.3 million based on management's assessment of the probability of the revenue thresholds being achieved.

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

NOTE 6. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

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

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

Avista Utilities makes continuing projections of:

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

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

- purchasing fuel for generation,
- when economical, selling fuel and substituting wholesale electric purchases, and

- other wholesale transactions to capture the value of generation and transmission resources and fuel delivery capacity contracts.

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

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

Natural gas resource optimization activities include:

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

The following table presents the underlying energy commodity derivative volumes as of December 31, 2012 that are expected to settle in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWH	Financial (1) MWH	Physical mmBTUs	Financial mmBTUs	Physical MWH	Financial MWH	Physical mmBTUs	Financial mmBTUs
2013	713	3,365	18,523	88,391	264	2,712	7,252	91,962
2014	397	801	6,394	55,407	377	1,844	1,786	33,623
2015	379	614	3,390	42,930	286	982	—	35,575
2016	367	—	1,365	455	287	—	—	—
2017	366	—	—	—	286	—	—	—
Thereafter	583	—	—	—	443	—	—	—

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

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

Foreign Currency Exchange Contracts

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

	2012	2011
Number of contracts	20	28
Notional amount (in United States dollars)	$ 12,621	$ 7,033
Notional amount (in Canadian dollars)	12,502	7,192

Interest Rate Swap Agreements

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

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

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

In May 2012, the Company cash settled interest rate swap contracts (notional amount of $75.0 million) and paid a total of $18.5 million. The interest rate swap contracts were settled in connection with the pricing of $80.0 million of First Mortgage Bonds. In September 2011, the Company cash settled interest rate swap contracts (notional amount of $85.0 million) and paid a total of $10.6 million. The interest rate swap contracts were settled in connection with the pricing of $85.0 million of First Mortgage Bonds.

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

Derivative Instruments Summary

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

		Fair Value			
Derivative	Balance Sheet Location	Asset	Liability	Collateral Netting	Net Asset (Liability)
Foreign currency contracts	Other current liabilities	$ 7	$ (34)	$ —	$ (27)
Interest rate contracts	Other current liabilities	—	(1,406)	—	(1,406)
Interest rate contracts	Other property and investments - net	7,265	—	—	7,265
Commodity contracts	Current utility energy commodity derivative assets	10,772	(6,633)	—	4,139
Commodity contracts	Non-current utility energy commodity derivative assets	18,779	(17,686)	—	1,093
Commodity contracts	Current utility energy commodity derivative liabilities	50,227	(89,449)	9,707	(29,515)
Commodity contracts	Other non-current liabilities and deferred credits	2,247	(28,558)	—	(26,311)
Total derivative instruments recorded on the balance sheet		$ 89,297	$ (143,766)	$ 9,707	$ (44,762)

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

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

Exposure to Demands for Collateral

The Company's derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement, in the event of a downgrade in the Company's credit ratings or changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against the Company's credit facilities and cash. The Company actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements. As of December 31, 2012, the Company had cash deposited as collateral of $10.1 million and letters of credit of $28.1 million outstanding related to its energy derivative contracts. The Consolidated Balance Sheet at December 31, 2012 reflects the offsetting of $9.7 million of cash collateral against net derivative positions where a legal right of offset exists.

Certain of the Company’s derivative instruments contain provisions that require the Company to maintain an investment grade credit rating from the major credit rating agencies. If the Company’s credit ratings were to fall below “investment grade,” it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position as of December 31, 2012 was $35.9 million. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2012, the Company could be required to post $25.8 million of additional collateral to its counterparties.

Credit Risk

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

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

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

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

The Company seeks to mitigate bilateral credit risk by:

- entering into bilateral contracts that specify credit terms and protections against default,

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

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

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

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

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

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

NOTE 7. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, the Colstrip Generating Project (Colstrip) located in southeastern Montana, and provides financing for its ownership interest in the project. The Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Consolidated Statements of Income. The Company's share of utility plant in service for Colstrip and accumulated depreciation were as follows as of December 31 (dollars in thousands):

	2012	2011
Utility plant in service	$ 344,958	$ 342,539
Accumulated depreciation	(234,126)	(225,746)

NOTE 8. PROPERTY, PLANT AND EQUIPMENT

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

	2012	2011
Avista Utilities:		
Electric production	$ 1,112,670	$ 1,094,223
Electric transmission	546,019	522,930
Electric distribution	1,217,827	1,157,012
Electric construction work-in-progress (CWIP) and other	244,761	205,437
Electric total	3,121,277	2,979,602
Natural gas underground storage	40,890	40,430
Natural gas distribution	704,839	683,948
Natural gas CWIP and other	57,745	41,077
Natural gas total	803,474	765,455
Common plant (including CWIP)	272,991	221,649
Total Avista Utilities	4,197,742	3,966,706
Ecova (1)	30,138	25,763
Other (1)	22,690	22,042
Total	$ 4,250,570	$ 4,014,511

(1) Included in other property and investments-net on the Consolidated Balance Sheets. Accumulated depreciation was $23.4 million as of December 31, 2012 and $20.3 million as of December 31, 2011 for Ecova and $13.7 million as of December 31, 2012 and $13.1 million as of December 31, 2011 for the other businesses.

NOTE 9. ASSET RETIREMENT OBLIGATIONS

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

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

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

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

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

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

	2012	2011	2010
Asset retirement obligation at beginning of year	$ 3,513	$ 3,887	$ 3,971
New liability recognized	—	—	19
Liability settled	(559)	(612)	(460)
Accretion expense	214	238	357
Asset retirement obligation at end of year	$ 3,168	$ 3,513	$ 3,887

NOTE 10. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering substantially all regular full-time employees at Avista Utilities. Individual benefits under this plan are based upon the employee’s years of service, date of hire and average compensation as specified in the plan. The Company’s funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $44 million in cash to the pension plan in 2012, $26 million in 2011 and $21 million in 2010. The Company expects to contribute $44 million in cash to the pension plan in 2013.

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

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

	2013	2014	2015	2016	2017	Total 2018-2022
Expected benefit payments	$ 24,504	$ 24,280	$ 25,434	$ 26,567	$ 27,797	$ 162,488

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

The Company provides certain health care and life insurance benefits for substantially all of its retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The Company elected to amortize the transition obligation of $34.5 million over a period of 20 years, beginning in 1993.

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

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

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

	2013	2014	2015	2016	2017	Total 2018-2022
Expected benefit payments	$ 6,099	$ 6,160	$ 6,261	$ 6,389	$ 6,571	$ 36,342

The Company expects to contribute $6.1 million to other postretirement benefit plans in 2013, 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, 2012 and 2011 and the components of net periodic benefit costs for the years ended December 31, 2012, 2011 and 2010 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2012	2011	2012	2011
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 494,192	$ 433,491	$ 104,730	$ 60,339
Service cost	15,551	12,936	2,804	1,805
Interest cost	24,349	24,134	5,056	4,126
Actuarial loss	72,170	44,148	24,543	42,476
Transfer of accrued vacation	—	—	336	450
Benefits paid	(21,643)	(20,517)	(4,928)	(4,466)
Benefit obligation as of end of year	$ 584,619	$ 494,192	$ 132,541	$ 104,730
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 328,150	$ 306,712	$ 22,455	$ 22,875
Actual return on plan assets	54,318	14,705	2,833	(420)
Employer contributions	44,000	26,000	—	—
Benefits paid	(20,407)	(19,267)	—	—
Fair value of plan assets as of end of year	$ 406,061	$ 328,150	$ 25,288	$ 22,455
Funded status	$ (178,558)	$ (166,042)	$ (107,253)	$ (82,275)
Unrecognized net actuarial loss	223,308	192,883	94,202	76,187
Unrecognized prior service cost	319	665	(856)	(1,005)
Unrecognized net transition obligation	—	—	—	505
Prepaid (accrued) benefit cost	45,069	27,506	(13,907)	(6,588)
Additional liability	(223,627)	(193,548)	(93,346)	(75,687)
Accrued benefit liability	$ (178,558)	$ (166,042)	$ (107,253)	$ (82,275)
Accumulated pension benefit obligation	$ 505,695	$ 429,135	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 49,232	$ 39,470
For fully eligible employees			$ 35,570	$ 29,597
For other participants			$ 47,739	$ 35,663
Included in accumulated comprehensive loss (income) (net of tax):				
Unrecognized net transition obligation	$ —	$ —	$ —	$ 328
Unrecognized prior service cost	207	433	(556)	(653)
Unrecognized net actuarial loss	145,150	125,374	61,231	49,522
Total	145,357	125,807	60,675	49,197
Less regulatory asset	(138,184)	(119,360)	(60,981)	(49,873)
Accumulated other comprehensive loss (income)	$ 7,173	$ 6,447	$ (306)	$ (676)

	Pension Benefits		Other Post-retirement Benefits	
	2012	2011	2012	2011
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	4.15%	5.04%	4.15%	4.98%
Discount rate for annual expense	5.04%	5.68%	4.98%	5.53%
Expected long-term return on plan assets	6.95%	7.40%	6.55%	7.00%
Rate of compensation increase	4.89%	4.87%		
Medical cost trend pre-age 65 – initial			7.00%	7.50%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2019	2017
Medical cost trend post-age 65 – initial			7.50%	8.00%
Medical cost trend post-age 65 – ultimate			5.00%	6.00%
Ultimate medical cost trend year post-age 65			2021	2018

	Pension Benefits			Other Post-retirement Benefits		
	2012	2011	2010	2012	2011	2010
Components of net periodic benefit cost:						
Service cost	$ 15,551	$ 12,936	$ 11,609	$ 2,804	$ 1,805	$ 684
Interest cost	24,349	24,134	23,231	5,056	4,126	2,624
Expected return on plan assets	(23,810)	(23,115)	(21,381)	(1,471)	(1,601)	(1,581)
Transition obligation recognition	—	—	—	505	505	505
Amortization of prior service cost	346	475	650	(149)	(149)	(149)
Net loss recognition	11,637	9,493	7,189	5,020	3,458	1,379
Net periodic benefit cost	$ 28,073	$ 23,923	$ 21,298	$ 11,765	$ 8,144	$ 3,462

Plan Assets

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

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

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

	2012	2011
Equity securities	51%	51%
Debt securities	31%	31%
Real estate	5%	5%
Absolute return	10%	10%
Other	3%	3%

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

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

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

The market-related value of pension plan assets was determined as of December 31, 2012 and 2011.

The following table discloses by level within the fair value hierarchy (see Note 17 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2012 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Mutual funds:				
Fixed income securities	$ 83,037	$ —	$ —	$ 83,037
U.S. equity securities	135,436	—	—	135,436
International equity securities	79,448	—	—	79,448
Absolute return (1)	20,764	—	—	20,764
Commodities (2)	8,258	—	—	8,258
Common/collective trusts:				
Fixed income securities	—	43,107	—	43,107
Real estate	—	—	17,596	17,596
Partnership/closely held investments:				
Absolute return (1)	—	—	17,755	17,755
Private equity funds (3)	—	—	660	660
Total	$ 326,943	$ 43,107	$ 36,011	$ 406,061

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

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

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

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

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

The table below discloses the summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2012 (dollars in thousands):

	Common/collective trusts	Partnership/closely held investments	
	Real estate	Absolute return	Private equity funds
Balance, as of January 1, 2012	$ 8,598	$ 16,587	$ 808
Realized gains	411	—	108
Unrealized gains (losses)	1,087	1,168	80
Purchases (sales), net	7,500	—	(336)
Balance, as of December 31, 2012	$ 17,596	$ 17,755	$ 660

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

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

The market-related value of other postretirement plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). The target asset allocation was 62 percent equity securities and 38 percent debt securities in 2012 and 2011.

The market-related value of other postretirement plan assets was determined as of December 31, 2012 and 2011.

The following table discloses by level within the fair value hierarchy (see Note 17 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2012 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 6	$ —	$ 6
Mutual funds:				
Fixed income securities	9,314	—	—	9,314
U.S. equity securities	10,266	—	—	10,266
International equity securities	5,702	—	—	5,702
Total	$ 25,282	$ 6	$ —	$ 25,288

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

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

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, 2012 by $20.8 million and the service and interest cost by $1.4 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, 2012 by $16.7 million and the service and interest cost by $1.1 million.

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

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

	2012	2011	2010
Employer 401(k) matching contributions	$ 8,168	$ 7,027	$ 5,405

The Company has an Executive Deferral Plan. This plan allows executive officers and other key employees the opportunity to defer until the earlier of their retirement, termination, disability or death, up to 75 percent of their base salary and/or up to 100 percent of their incentive payments. Deferred compensation funds are held by the Company in a Rabbi Trust. There were deferred compensation assets included in other property and investments-net and corresponding deferred compensation liabilities included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets of the following amounts as of December 31 (dollars in thousands):

	2012	2011
Deferred compensation assets and liabilities	$ 8,806	$ 8,653

NOTE 11. ACCOUNTING FOR INCOME TAXES

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

	2012	2011	2010
Taxes currently provided	$ 19,812	$ 32,625	$ 13,423
Deferred income tax expense	21,449	24,007	37,734
Total income tax expense	$ 41,261	$ 56,632	$ 51,157

A reconciliation of federal income taxes derived from statutory federal tax rates (35 percent in 2012, 2011 and 2010) 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):

	2012	2011	2010
Federal income taxes at statutory rates	$ 42,021	$ 56,060	$ 51,137
Increase (decrease) in tax resulting from:			
Tax effect of regulatory treatment of utility plant differences	2,432	1,798	2,761
State income tax expense	985	687	624
Settlement of prior year tax returns and adjustment of tax reserves	(2,198)	163	(1,030)
Manufacturing deduction	(1,100)	(1,099)	(1,630)
Other	(879)	(977)	(705)
Total income tax expense	$ 41,261	$ 56,632	$ 51,157

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):

	2012	2011
Deferred income tax assets:		
Allowance for doubtful accounts	$ 12,140	$ 12,086
Reserves not currently deductible	5,923	6,302
Net operating loss from subsidiary acquisition	11,136	14,867
Deferred compensation	3,631	3,248
Unfunded benefit obligation	94,891	80,939
Utility energy commodity derivatives	22,953	38,999
Power and natural gas deferrals	12,490	9,545
Tax credits	19,401	16,924
Other	19,291	18,838
Total deferred income tax assets	201,856	201,748
Deferred income tax liabilities:		
Intangible assets from subsidiary acquisition	5,582	8,334
Differences between book and tax basis of utility plant	494,579	478,604
Regulatory asset for pensions and other postretirement benefits	107,243	91,125
Power exchange contract	10,753	15,571
Utility energy commodity derivatives	22,954	38,992
Loss on reacquired debt	6,751	7,193
Interest rate swaps	12,308	3,720
Settlement with Coeur d'Alene Tribe	13,448	19,185
Other	18,227	14,505
Total deferred income tax liabilities	691,845	677,229
Net deferred income tax liability	$ 489,989	$ 475,481
Current deferred income tax asset	$ 34,281	$ 30,473
Ecova long-term deferred income tax asset (1)	607	—
Long-term deferred income tax liability	524,877	505,954
Net deferred income tax liability	$ 489,989	$ 475,481

(1) Ecova files its own tax return and its deferred tax assets and liabilities cannot be netted with Avista Corp.'s deferred income tax assets and liabilities. This balance is included in other deferred charges on the Consolidated Balance Sheet at December 31, 2012.

As of December 31, 2012, the Company had $13.9 million of state tax credit carryforwards. State tax credits expire from 2015 to 2025. The Company recognizes the effect of state tax credits generated from utility plant as they are utilized.

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

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon and Montana. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The Internal Revenue Service (IRS) has completed its examination of all tax years through 2009 and all issues were resolved related to these years. The IRS has not completed an examination of the Company's 2010 through 2011 federal income tax returns. The Company does not believe that any open tax years for federal or state income taxes could result in any adjustments that would be significant to the consolidated financial statements.

The Company did not incur any penalties on income tax positions in 2012, 2011 or 2010. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operating expense.

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

	2012	2011
Regulatory assets for deferred income taxes	$ 79,406	$ 84,576

NOTE 12. ENERGY PURCHASE CONTRACTS

Avista Utilities has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The termination dates of the contracts range from one month to the year 2055. Total expenses for power purchased, natural gas purchased, fuel for generation and other fuel costs, which are included in utility resource costs in the Consolidated Statements of Income, were as follows for the years ended December 31 (dollars in thousands):

	2012	2011	2010
Utility power resources	$ 523,416	$ 557,619	$ 649,408

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):

	2013	2014	2015	2016	2017	Thereafter	Total
Power resources	$ 196,877	$ 132,378	$ 118,054	$ 117,779	$ 116,580	$ 1,025,941	$ 1,707,609
Natural gas resources	109,406	96,092	77,688	60,104	51,950	678,042	1,073,282
Total	$ 306,283	$ 228,470	$ 195,742	$ 177,883	$ 168,530	$ 1,703,983	$ 2,780,891

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

In addition, Avista Utilities has operational agreements, settlements and other contractual obligations for its generation, transmission and distribution facilities. The expenses associated with these agreements are reflected as other operating expenses in the Consolidated Statements of Income. The following table details future contractual commitments for these agreements (dollars in thousands):

	2013	2014	2015	2016	2017	Thereafter	Total
Contractual obligations	$ 30,913	$ 31,732	$ 29,259	$ 35,844	$ 27,708	$ 230,453	$ 385,909

Avista Utilities has fixed contracts with certain Public Utility Districts (PUD) to purchase portions of the output of certain generating facilities. Although Avista Utilities has no investment in the PUD generating facilities, the fixed contracts obligate

Avista Utilities to pay certain minimum amounts (based in part on the debt service requirements of the PUD) whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in utility resource costs in the Consolidated Statements of Income. Expenses under these PUD contracts were as follows for the years ended December 31 (dollars in thousands):

	2012	2011	2010
PUD contract costs	$ 8,436	$ 10,533	$ 8,287

Information as of December 31, 2012 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
Douglas County PUD:						
Wells Project	3.4%	24,048	2,716	874	3,117	2018
Grant County PUD:						
Priest Rapids and Wanapum Projects	3.3%	65,800	5,717	2,425	30,655	2055
Totals		89,848	$ 8,433	$ 3,299	$ 33,772	

(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 2012. Debt service costs are included in annual costs.

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

	2013	2014	2015	2016	2017	Thereafter	Total
Minimum payments	$ 3,348	$ 3,332	$ 3,223	$ 3,222	$ 3,220	$ 42,988	$ 59,333

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

NOTE 13. SHORT-TERM BORROWINGS

Avista Corp.

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

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

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2012, the Company was in compliance with this covenant.

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

	2012	2011	2010
Balance outstanding at end of period	$ 52,000	$ 61,000	$ 110,000
Letters of credit outstanding at end of period	$ 35,885	$ 29,030	$ 27,126
Average interest rate at end of period	1.12%	1.12%	0.57%

Ecova

In July 2012, Ecova entered into a $125.0 million committed line of credit agreement with financial institutions that replaced its $60.0 million committed credit agreement and has an expiration date of July 2017. The credit agreement is secured by all of Ecova's assets excluding investments and funds held for clients.

The committed line of credit agreement contains customary covenants and default provisions, including a covenant which requires that Ecova's "Consolidated Total Funded Debt to EBITDA Ratio" (as defined in the credit agreement) must be 2.50 to 1.00 or less, with provisions in the credit agreement allowing for a temporary increase of this ratio if a qualified acquisition is consummated by Ecova. In addition, Ecova's "Consolidated Fixed Charge Coverage Ratio" (as defined in the credit agreement) must be greater than 1.50 to 1.00 as of the last day of any fiscal quarter. As of December 31, 2012, Ecova was in compliance with these covenants.

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

	2012	2011	2010
Balance outstanding at end of period	$ 54,000	$ 35,000	$ —
Average interest rate at end of period	2.21%	2.38%	—%

During 2011, Ecova's committed line of credit balance was classified as short-term and was included in Short-term borrowings on the Consolidated Balance Sheet. During 2012, the balance has been classified as long-term and is included in Long-term borrowings under committed line of credit on the Consolidated Balance Sheet.

NOTE 14. LONG-TERM DEBT

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

Maturity Year	Description	Interest Rate	2012	2011
2012	Secured Medium-Term Notes	7.37%	$ —	$ 7,000
2013	First Mortgage Bonds	1.68%	50,000	50,000
2018	First Mortgage Bonds	5.95%	250,000	250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2020	First Mortgage Bonds	3.89%	52,000	52,000
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (2)	(2)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2047	First Mortgage Bonds (3)	4.23%	80,000	—
	Total secured long-term debt		1,336,700	1,263,700
2023	Unsecured Pollution Control Bonds	6.00%	—	4,100
	Other long-term debt and capital leases		5,092	5,455
	Settled interest rate swaps		(27,900)	(10,629)
	Unamortized debt discount		(1,453)	(1,626)
	Total		1,312,439	1,261,000
	Secured Pollution Control Bonds held by Avista Corporation (1) (2)		(83,700)	(83,700)
	Current portion of long-term debt		(50,372)	(7,474)
	Total long-term debt		$ 1,178,367	$ 1,169,826

(1) In December 2010, $66.7 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due 2032, which had been held by Avista Corp. since 2008, were refunded by a new bond issue (Series 2010A). The new bonds were not offered to the public and were purchased by Avista Corp. due to

market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Consolidated Balance Sheet.

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

(3) In November 2012, the Company issued $80.0 million of 4.23 percent First Mortgage Bonds due in 2047.

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

	2013	2014	2015	2016	2017	Thereafter	Total
Debt maturities	$ 50,000	$ —	$ —	$ —	$ —	$ 1,254,547	$ 1,304,547

Substantially all utility properties owned by the Company are subject to the lien of the Company's mortgage indenture. Under the Mortgage and Deed of Trust securing the Company's First Mortgage Bonds (including Secured Medium-Term Notes), the Company may issue additional First Mortgage Bonds in an aggregate principal amount equal to the sum of: 1) 66-2/3 percent of the cost or fair value (whichever is lower) of property additions which have not previously been made the basis of any application under the Mortgage, or 2) an equal principal amount of retired First Mortgage Bonds which have not previously been made the basis of any application under the Mortgage, or 3) deposit of cash. However, the Company may not issue any additional First Mortgage Bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the Company's "net earnings" (as defined in the Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the First Mortgage Bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2012, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited the issuance of $640.1 million in aggregate principal amount of additional First Mortgage Bonds.

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

Nonrecourse Long-Term Debt

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

	2013	2014	2015	2016	Total
Debt maturities	$ 14,965	$ 16,407	$ 1,431	$ —	$ 32,803

NOTE 15. LONG-TERM DEBT TO AFFILIATED TRUSTS

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly. The distribution rates paid were as follows during the years ended December 31:

	2012	2011	2010
Low distribution rate	1.19%	1.13%	1.13%
High distribution rate	1.40	1.40	1.41
Distribution rate at the end of the year	1.19	1.40	1.17

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

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

NOTE 16. LEASES

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from 1 to forty-five years. Rental expense under operating leases was as follows for the years ended December 31 (dollars in thousands):

	2012	2011	2010
Rental expense	$ 8,152	$ 6,463	$ 6,080

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

	2013	2014	2015	2016	2017	Thereafter	Total
Minimum payments required	$ 6,794	$ 6,352	$ 3,771	$ 1,744	$ 1,308	$ 4,883	$ 24,852

NOTE 17. FAIR VALUE

The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable and short-term borrowings are reasonable estimates of their fair values. Long-term debt (including current portion, but excluding capital leases), nonrecourse long-term debt and long-term debt to affiliated trusts are reported at carrying value on the Consolidated Balance Sheets.

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

	2012		2011	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 951,000	$ 1,164,639	$ 962,100	$ 1,135,536
Long-term debt (Level 3)	302,000	320,892	222,000	234,226
Nonrecourse long-term debt (Level 3)	32,803	35,297	46,471	51,974
Long-term debt to affiliated trusts (Level 3)	51,547	43,686	51,547	43,810

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

The fair value hierarchy prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement).

The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 – Pricing inputs include significant inputs that are generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of Avista Corp.'s nonperformance risk on its liabilities.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Consolidated Balance Sheets as of December 31, 2012 and 2011 at fair value on a recurring basis (dollars in thousands):

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

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

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

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

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

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

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.8 million as of December 31, 2012 and $1.3 million as of December 31, 2011.

Level 3 Fair Value

For power exchange agreements, the Company compares the Level 2 brokered quotes and forward price curves described above to an internally developed forward price which is based on the average operating and maintenance (O&M) charges from four surrogate nuclear power plants around the country for the current year. Because the nuclear power plant O&M charges are only known for one year, all forward years are estimated assuming an annual escalation. In addition to the forward price being estimated using unobservable inputs, the Company also estimates the volumes of the transactions that will take place in the future based on historical average transaction volumes per delivery year (November to April). Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, a change in the current year O&M charges for the surrogate plants is accompanied by a directionally similar change in O&M charges in future years. There is generally not a correlation between external market prices and the O&M charges used to develop the internal forward price.

For power commodity option agreements, the Company uses the Black-Scholes-Merton valuation model to estimate the fair value, and this model includes significant inputs not observable or corroborated in the market. These inputs include 1) the strike price (which is an internally derived price based on a combination of generation plant heat rate factors, natural gas market pricing, delivery and other O&M charges, 2) estimated delivery volumes for years beyond 2013, and 3) volatility rates for periods beyond January 2016. Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, changes in overall commodity market prices and volatility rates are accompanied by directionally similar changes in the strike price and volatility assumptions used in the calculation.

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

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of December 31, 2012 (dollars in thousands):

	Fair Value (Net) at December 31, 2012	Valuation Technique	Unobservable Input	Range
Power exchange agreements	$ (18,692)	Surrogate facility pricing	O&M charges	$30.49-$53.82/MWh (1)
			Escalation factor	5% - 2013 to 2015
				3% - 2016 to 2019
			Transaction volumes	365,619 - 379,156 MWhs
Power option agreements	(1,480)	Black-Scholes-Merton	Strike price	$52.61/MWh - 2013
				$76.63/MWh - 2019
			Delivery volumes	128,491 - 287,147 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreements	(2,379)	Internally derived weighted average cost of gas	Forward purchase prices	$3.19 - $3.38/mmBTU
			Forward sales prices	$3.29 - $4.46/mmBTU
			Purchase volumes	135,000 - 465,000 mmBTUs
			Sales volumes	140,010 - 620,000 mmBTUs

(1) The average O&M charges for 2012 were $40.87 per MWh.
(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.33 for 2012 to 0.21 in January 2016.

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

The following table presents activity for energy commodity derivative assets (liabilities) measured at fair value using significant unobservable inputs (Level 3) for the years ended December 31 (dollars in thousands):

	Natural Gas Exchange Agreements	Power Exchange Agreements	Power Option Agreements	Total
Year ended December 31, 2012:				
Balance as of January 1, 2012	$ (1,688)	$ (9,910)	$ (1,260)	$ (12,858)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	343	(15,236)	(220)	(15,113)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(1,034)	6,454	—	5,420
Transfers to/from other categories	—	—	—	—
Ending balance as of December 31, 2012	$ (2,379)	$ (18,692)	$ (1,480)	$ (22,551)
Year ended December 31, 2011:				
Balance as of January 1, 2011	$ —	$ 15,793	$ (2,334)	$ 13,459
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	2,621	(28,571)	1,074	(24,876)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	95	2,868	—	2,963
Transfers from other categories (2)	(4,404)	—	—	(4,404)
Ending balance as of December 31, 2011	$ (1,688)	$ (9,910)	$ (1,260)	$ (12,858)
Year ended December 31, 2010:				
Balance as of January 1, 2010	$ —	$ 57,250	$ (7,780)	$ 49,470
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	—	(39,180)	5,446	(33,734)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	—	(2,277)	—	(2,277)
Transfers to/from other categories	—	—	—	—
Ending balance as of December 31, 2010	$ —	$ 15,793	$ (2,334)	$ 13,459

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

(2) A derivative contract was reclassified from Level 2 to Level 3 during 2011 due to a particular unobservable input becoming more significant to the fair value measurement. There were not any reclassifications between Level 1 and Level 2. The Company's policy is to reclassify identified items as of the end of the reporting period.

NOTE 18. COMMON STOCK

The Company has a Direct Stock Purchase and Dividend Reinvestment Plan under which the Company’s shareholders may automatically reinvest their dividends and make optional cash payments for the purchase of the Company’s common stock at current market value. Shares issued under this plan in 2012, 2011 and 2010 are disclosed in the Consolidated Statements of Equity and Redeemable Noncontrolling Interests.

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

In August 2012, the Company entered into two sales agency agreements under which the Company may sell up to 2,726,390 shares of its common stock from time to time. As of December 31, 2012, the Company had 1,795,199 shares available to be issued under these agreements.

In August 2010, the Company entered into an amended and restated sales agency agreement with a sales agent to issue up to 3,087,500 shares of its common stock from time to time. The Company originally entered into a sales agency agreement to issue up to 1,250,000 shares of its common stock in December 2009. This sales agency agreement was terminated in August 2012.

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

	2012	2011	2010
Shares issued under sales agency agreement	931,191	807,000	2,054,110

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2012 and 2011.

NOTE 19. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORPORATION SHAREHOLDERS

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

	2012	2011	2010
Numerator:			
Net income attributable to Avista Corporation shareholders	$ 78,210	$ 100,224	$ 92,425
Subsidiary earnings adjustment for dilutive securities	(38)	(473)	(226)
Adjusted net income attributable to Avista Corporation shareholders for computation of diluted earnings per common share	$ 78,172	$ 99,751	$ 92,199
Denominator:			
Weighted-average number of common shares outstanding-basic	59,028	57,872	55,595
Effect of dilutive securities:			
Performance and restricted stock awards	162	172	157
Stock options	11	48	72
Weighted-average number of common shares outstanding-diluted	59,201	58,092	55,824
Potential shares excluded in calculation (1)	—	—	—
Earnings per common share attributable to Avista Corporation shareholders:			
Basic	$ 1.32	$ 1.73	$ 1.66
Diluted	$ 1.32	$ 1.72	$ 1.65

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

NOTE 20. STOCK COMPENSATION PLANS

Avista Corp. (Excluding Ecova)

1998 Plan

In 1998, the Company adopted, and shareholders approved, the Long-Term Incentive Plan (1998 Plan). Under the 1998 Plan, certain key employees, officers and non-employee directors of the Company and its subsidiaries may be granted stock options, stock appreciation rights, stock awards (including restricted stock) and other stock-based awards and dividend equivalent rights. The Company has available a maximum of 4.5 million shares of its common stock for grant under the 1998 Plan. As of December 31, 2012, 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, 2012, 1.9 million shares were remaining for grant under this plan.

Stock Compensation

The Company records compensation cost relating to share-based payment transactions in the financial statements based on the fair value of the equity or liability instruments issued. The Company recorded stock-based compensation expense (included in other operating expenses) and income tax benefits in the Consolidated Statements of Income of the following amounts for the years ended December 31 (dollars in thousands):

	2012	2011	2010
Stock-based compensation expense	$ 5,792	$ 5,756	$ 4,916
Income tax benefits	2,027	2,014	1,720

Stock Options

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

	2012	2011	2010
Number of shares under stock options:			
Options outstanding at beginning of year	92,499	201,674	523,973
Options granted	—	—	—
Options exercised	(89,499)	(107,575)	(101,649)
Options canceled	—	(1,600)	(220,650)
Options outstanding and exercisable at end of year	3,000	92,499	201,674
Weighted average exercise price:			
Options exercised	$ 10.63	$ 12.25	$ 11.51
Options canceled	$ —	$ 11.80	$ 22.60
Options outstanding and exercisable at end of year	$ 12.41	$ 10.69	$ 11.53
Cash received from options exercised (in thousands)	$ 951	$ 1,318	$ 2,179
Intrinsic value of options exercised (in thousands)	$ 1,349	$ 1,279	$ 1,006
Intrinsic value of options outstanding (in thousands)	$ 35	$ 1,393	$ 2,217

Information for options outstanding and exercisable as of December 31, 2012 is as follows:

Exercise Price	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$12.41	3,000	12.41	0.35

As of December 31, 2012 and 2011, the Company's stock options were fully vested and expensed.

Restricted Shares

Restricted share awards 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, 2012 was 0.7 years. The following table summarizes restricted stock activity for the years ended December 31:

	2012	2011	2010
Unvested shares at beginning of year	93,482	84,134	71,904
Shares granted	70,281	50,618	43,800
Shares canceled	(790)	(431)	—
Shares vested	(45,855)	(40,839)	(31,570)
Unvested shares at end of year	117,118	93,482	84,134
Weighted average fair value at grant date	$ 25.83	$ 23.06	$ 19.80
Unrecognized compensation expense at end of year (in thousands)	$ 1,428	$ 932	$ 735
Intrinsic value, unvested shares at end of year (in thousands)	$ 2,824	$ 2,407	$ 1,895
Intrinsic value, shares vested during the year (in thousands)	$ 1,173	$ 934	$ 682

Performance Shares

Performance share awards vest after a period of three years and are payable in cash or Avista Corp. common stock at the end of the three-year period. Performance share awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific performance conditions. Based on the attainment of the performance condition, the amount of cash paid or common stock issued will range from 0 to 150 percent of the performance shares granted for grants prior to 2011 and 0 to 200 percent for grants in 2011 and after, depending on the change in the value of the Company's common stock relative to an external benchmark. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest.

Performance share awards entitle the grantee to shares of common stock or cash payable once the service condition is satisfied. Based on attainment of the performance condition, grantees may receive 0 to 150 percent of the original shares granted for grants prior to 2011 and 0 to 200 percent for shares granted in 2011 and after. 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 awarded. 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:

	2012	2011	2010
Risk-free interest rate	0.3%	1.2%	1.4%
Expected life, in years	3	3	3
Expected volatility	22.7%	26.9%	27.8%
Dividend yield	4.5%	4.7%	4.6%
Weighted average grant date fair value (per share)	$ 26.06	$ 20.79	$ 15.30

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

The following summarizes performance share activity:

	2012	2011	2010
Opening balance of unvested performance shares	351,345	325,700	300,601
Performance shares granted	181,000	184,600	168,700
Performance shares canceled	(4,544)	(2,177)	—
Performance shares vested	(168,101)	(156,778)	(143,601)
Ending balance of unvested performance shares	359,700	351,345	325,700
Intrinsic value of unvested performance shares (in thousands)	$ 8,672	$ 9,047	$ 7,335
Unrecognized compensation expense (in thousands)	$ 3,800	$ 2,991	$ 2,330

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2012 was 1.5 years. Unrecognized compensation expense as of December 31, 2012 will be recognized during 2013. The following summarizes the impact of the market condition on the vested performance shares:

	2012	2011	2010
Performance shares vested	168,101	156,778	143,601
Impact of market condition on shares vested	(168,101)	(15,678)	21,540
Shares of common stock earned	—	141,100	165,141
Intrinsic value of common stock earned (in thousands)	$ —	$ 3,633	$ 3,719

Shares earned under this plan are distributed to participants in the quarter following vesting.

Outstanding performance share awards 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, 2012 and 2011, the Company had recognized compensation expense and a liability of $0.7 million and $1.0 million related to the dividend component of performance share grants.

Ecova

Ecova has an employee stock incentive plan under which certain employees of Ecova may be granted options to purchase shares of Ecova at prices no less than the estimated fair value on the date of grant. The fair value of each employee option grant is estimated on the date of grant using the Black-Scholes option-pricing model and certain assumptions deemed reasonable by management. Options outstanding under this plan generally vest over periods of four years from the date granted and terminate ten years from the date granted. Unrecognized compensation expense for stock based awards at Ecova was $3.1 million as of December 31, 2012, which will be expensed during 2013 through 2016.

In 2007, Ecova amended its employee stock incentive plan to provide an annual window at which time holders of common stock can put their shares back to Ecova providing the shares are held for a minimum of six months. In 2009, Ecova amended its employee stock incentive plan to make this put feature optional for future stock option grants. Stock is reacquired at fair market value less exercise price at the date of reacquisition. Additionally, there were redeemable noncontrolling interests related to the Cadence Network acquisition, as the previous owners can exercise a right to put their stock back to Ecova (see Note 5 for further information). The following amounts of common stock were repurchased from Ecova employees during the years ended December 31 (dollars in thousands):

	2012	2011	2010
Stock repurchased from Ecova employees	$ 599	$ 464	$ 2,593

NOTE 21. COMMITMENTS AND CONTINGENCIES

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

Federal Energy Regulatory Commission Inquiry

In April 2004, the Federal Energy Regulatory Commission (FERC) approved the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) between Avista Corp. doing business as Avista Utilities, Avista Energy and the FERC's Trial Staff which stated that there was: (1) no evidence that any executives or employees of Avista Utilities or Avista Energy knowingly engaged in or facilitated any improper trading strategy during 2000 and 2001; (2) no evidence that Avista Utilities or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; and (3) no finding that Avista Utilities or Avista Energy withheld relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001 (Trading Investigation). The Attorney General of the State of California (California AG), the California Electricity Oversight Board, and the City of Tacoma, Washington (City of Tacoma) challenged the FERC's decisions approving the Agreement in Resolution, which are now pending before the United States Court of Appeals for the Ninth Circuit (Ninth Circuit). In May 2004, the FERC provided notice that Avista Energy was no longer subject to an investigation reviewing certain bids above $250 per MW in the short-term energy markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX) from May 1, 2000 to October 2, 2000 (Bidding Investigation). That matter is also pending before the Ninth Circuit, after the California AG, Pacific Gas & Electric (PG&E), Southern California Edison Company (SCE) and the California Public Utilities Commission (CPUC) filed petitions for review in 2005.

Based on the FERC's order approving the Agreement in Resolution in the Trading Investigation and order denying rehearing requests, the Company does not expect that this proceeding will have any material effect on its financial condition, results of operations or cash flows. Furthermore, based on information currently known to the Company regarding the Bidding Investigation and the fact that the FERC Staff did not find any evidence of manipulative behavior, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows.

California Refund Proceeding

In July 2001, the FERC ordered an evidentiary hearing to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the CalISO and the CalPX during the period from October 2, 2000 to June 20, 2001 (Refund Period). Proposed refunds are based on the calculation of mitigated market clearing prices for each hour. The FERC ruled that if the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, sellers may document these costs and limit their refund liability commensurately. In September 2005, Avista Energy submitted its cost filing claim pursuant to the FERC's August 2005 order. The filing was initially accepted by the FERC, but in March 2011, the FERC ordered Avista Energy to remove any return on equity in a compliance filing with the CalISO, which Avista Energy did in April 2011. A challenge to Avista Energy's cost filing by the California AG, the CPUC, PG&E and SCE was denied in July 2011 as a collateral attack on the FERC's prior orders accepting Avista Energy's cost filing. In July 2011, the California AG, the CPUC, PG&E and SCE filed a petition for review of the FERC's orders regarding Avista Energy's cost filing with the Ninth Circuit.

The 2001 bankruptcy of PG&E resulted in a default on its payment obligations to the CalPX. As a result, Avista Energy has not been paid for all of its energy sales during the Refund Period. Those funds are now in escrow accounts and will not be released until the FERC issues an order directing such release in the California refund proceeding. The CalISO continues to work on its compliance filing for the Refund Period, which will show “who owes what to whom.” In July 2011, the FERC accepted the preparatory rerun compliance filings by the CalPX and CalISO, and responded to the CalPX request for guidance on issues related to completing the final determination of “who owes what to whom.” The FERC directed both the CalISO and the CalPX to prepare and submit to the FERC their final refund rerun compliance filings. The FERC's order also directs the CalPX to pay past due principal amounts to governmental entities. In February 2012, the FERC denied the challenges made to the July 2011 order by the California AG, the CPUC, PG&E and SCE. As of September 30, 2012, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from the defaulting parties.

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

A FERC hearing commenced on April 11, 2012 and concluded on July 19, 2012. On August 27, 2012, the Presiding Administrative Law Judge issued a partial initial decision granting Avista Utilities' motion for summary disposition, based on the stipulation by the California Parties that there are no allegations of tariff violations made against Avista Utilities in this proceeding and therefore no tariff violations by Avista Utilities that affected the market clearing price in any hour during the Summer Period. On November 2, 2012, FERC issued an order affirming the partial initial decision and dismissing Avista Utilities from the proceeding, thereby terminating all claims against Avista Utilities for the Summer Period. In the same order, FERC also held that a market-wide remedy would not be appropriate with regard to any respondent during the Summer Period. FERC stated that it is clear that the Ninth Circuit did not mandate a specific remedy on remand and, instead, left it to the FERC's discretion to determine which remedy would be appropriate. On December 3, 2012, the California Parties filed a request for clarification and rehearing of the November 2, 2012 order. On February 15, 2013, the Administrative Law Judge issued an initial decision finding that certain Respondents committed various tariff and other violations that affected the market clearing price in the California organized markets during the Summer Period. The tariff violations identified for Avista Energy are type II and III bidding violations; false export violations; and selling ancillary services without market-based rate authority. The initial decision did not discuss evidence offered by Avista Energy, on an hour by hour basis, rebutting the alleged violations and Avista Energy is currently preparing briefs on exceptions which will identify these errors. With respect to Avista Energy's one exchange transaction with the CalISO during the Refund Period, the judge made no findings with respect to the justness and reasonableness of that transaction, but nonetheless determined that Avista Energy owed approximately $0.2 million in refunds with regard to the transaction.

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

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. In August 2007, the Ninth Circuit found that the FERC, in denying the request for refunds, had failed to take into account new evidence of market manipulation in the California energy market and its potential ties to the Pacific Northwest energy market and that such failure was arbitrary and capricious and, accordingly, remanded the case to the FERC, stating that the FERC's findings must be reevaluated in light of the evidence. In addition, the Ninth Circuit concluded that the FERC abused its discretion in denying potential relief for transactions involving energy that was purchased by the California Energy Resources Scheduling (CERS) in the Pacific Northwest and ultimately consumed in California. The Ninth Circuit expressly declined to direct the FERC to grant refunds. The Ninth Circuit denied petitions for rehearing by various parties, and remanded the case to the FERC in April 2009.

On October 3, 2011, the FERC issued an Order on Remand, finding that, in light of the Ninth Circuit's remand order, additional procedures are needed to address possible unlawful activity that may have influenced prices in the Pacific Northwest spot market during the period from December 25, 2000 through June 20, 2001. The Order establishes an evidentiary, trial-type hearing before an Administrative Law Judge (ALJ), and reopens the record to permit parties to present evidence of unlawful market activity during the relevant period. The Order also allows participants to supplement the record with additional evidence on CERS transactions in the Pacific Northwest spot market from January 18, 2001 to June 20, 2001. The Order states that parties seeking refunds must submit evidence demonstrating that specific unlawful market activity occurred, and must demonstrate that such activity directly affected negotiations with respect to the specific contract rate about which they complain. Simply alleging a general link between the dysfunctional spot market in California and the Pacific Northwest spot market will not be sufficient to establish a causal connection between a particular seller's alleged unlawful activities and the specific contract negotiations at issue. Claimants filed notice of their claims on August 17, 2012, and they filed their direct testimony on September 21, 2012. Respondents' filed their answering testimony on December 17, 2012 and staff filed its answering testimony on February 5, 2013. Respondents' cross-answering testimony is due February 22, 2013 and claimants' rebuttal testimony is due March 12, 2013. The hearing is scheduled to begin on April 15, 2013. On July 11, 2012, Avista Energy and Avista Utilities filed settlements of all issues in this docket with regard to the claims made by the City of Tacoma. On September 21, 2012, and September 26, 2012, the FERC issued orders approving the settlements between the City of Tacoma and Avista Utilities and Avista Energy, respectively, thus terminating those claims. The two remaining direct claimants against Avista Utilities and Avista Energy in this proceeding are the City of Seattle, Washington, and the California Attorney General (on behalf of CERS).

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

California Attorney General Complaint (the "Lockyer Complaint")

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

In March 2008, the FERC issued an order establishing a trial-type hearing to address "whether any individual public utility seller's violation of the FERC's market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period.” Purchasers in the California markets were given the opportunity to present evidence that “any seller that violated the quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus cause its market-based rates to be unjust and unreasonable.” In March 2010, the Presiding ALJ granted the motions for summary disposition and found that a hearing was “unnecessary” because the California AG, CPUC, PG&E and SCE “failed to apply the appropriate test to determine market power during the relevant time period.” The judge determined that “[w]ithout a proper showing of market power, the California Parties failed to establish a prima facie case.” In May 2011, the FERC affirmed “in all respects” the ALJ's decision. In June 2011, the California AG, CPUC, PG&E and SCE filed for rehearing of that order. Those rehearing requests were denied by the FERC on June 13, 2012. On June 20, 2012, the California AG, CPUC, PG&E and SCE filed a petition for review of the FERC's order with the Ninth Circuit. On February 6, 2013, the California AG, CPUC, PG&E, and SCE filed an unopposed motion with the Ninth Circuit, requesting that a briefing schedule be established, such that petitioners' joint opening brief would be due May 17, 2013; respondents' answering brief would be due July 16, 2013; respondent-intervenors' joint brief would be due August 6, 2013; and petitioners' optional joint reply brief would be due September 10, 2013.

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

Colstrip Generating Project Complaint

In March 2007, two families that own property near the holding ponds from Units 3 & 4 of the Colstrip Generating Project (Colstrip) filed a complaint against the owners of Colstrip and Hydrometrics, Inc. in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs alleged that the holding ponds and remediation activities adversely impacted their property. They alleged contamination, decrease in water tables, reduced flow of streams on their property and other similar impacts to their property. They also sought punitive damages, attorney's fees, an order by the court to remove certain ponds, and the forfeiture of profits earned from the generation of Colstrip. In September 2010, the owners of Colstrip filed a motion with the court to enforce a settlement agreement that would resolve all issues between the parties. In October 2011 the court issued an order which enforces the settlement agreement. The plaintiffs subsequently appealed the court's decision and, on December 31, 2012, the Montana Supreme Court issued its decision, holding that the District Court properly granted the motion to enforce the settlement agreement. A petition for rehearing before the Supreme Court was denied on February 5, 2013. Under the settlement, Avista Corp.'s portion of payment (which was accrued in 2010) to the plaintiffs was not material to its financial condition, results of operations or cash flows.

Sierra Club and Montana Environmental Information Center Notice

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

Harbor Oil Inc. Site

Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, the Environmental Protection Agency (EPA) Region 10 provided notification to Avista Corp. and several other parties, as customers of Harbor Oil, that the EPA had determined that hazardous substances were released at the Harbor Oil site in Portland, Oregon and that Avista Corp. and several other parties may be liable for investigation and cleanup of the site under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as the federal “Superfund” law, which provides for joint and several liability. The initial indication from the EPA is that the site may be contaminated with PCBs, petroleum hydrocarbons, chlorinated solvents and heavy metals. Six potentially responsible parties, including Avista Corp., signed an Administrative Order on Consent with the EPA on May 31, 2007 to conduct a remedial investigation and feasibility study (RI/FS). The draft final RI/FS was submitted to the EPA in December 2011 and was accepted as pre-final in March 2012. The EPA issued a notice of its plan to make a finding of No Further Action in November

2012. Should the EPA make a No Further Action determination, the EPA stated it would then propose removal of the site from the National Priority List. Based on the review of its records related to Harbor Oil, the Company does not believe it is a significant contributor to this potential environmental contamination based on the small volume of waste oil it delivered to the Harbor Oil site. As such, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows. The Company has expensed its share of the RI/FS ($0.5 million) for this matter.

Spokane River Licensing

The Company owns and operates six hydroelectric plants on the Spokane River. Five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls) are regulated under one 50-year FERC license issued in June 2009 and are referred to as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. The license incorporated the 4(e) conditions that were included in the December 2008 Settlement Agreement with the United States Department of Interior and the Coeur d'Alene Tribe, as well as the mandatory conditions that were agreed to in the Idaho 401 Water Quality Certifications and in the amended Washington 401 Water Quality Certification.

As part of the Settlement Agreement with the Washington Department of Ecology (Ecology), the Company has participated in the Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On May 20, 2010, the EPA approved the TMDL and on May 27, 2010, Ecology filed an amended 401 Water Quality Certification with the FERC for inclusion into the license. The amended 401 Water Quality Certification includes the Company's level of responsibility, as defined in the TMDL, for low dissolved oxygen levels in Lake Spokane. The Company submitted a draft Water Quality Attainment Plan for Dissolved Oxygen to Ecology in May 2012 and this was approved by Ecology in September 2012. This plan was subsequently approved by the FERC. The Company will begin to implement this plan, and management believes costs will not be material. On July 16, 2010, the City of Post Falls and the Hayden Area Regional Sewer Board filed an appeal with the United States District Court for the District of Idaho with respect to the EPA's approval of the TMDL. The Company, the City of Coeur d'Alene, Kaiser Aluminum and the Spokane River Keeper subsequently moved to intervene in the appeal. In September 2011, the EPA issued a stay to the litigation that will be in effect until either the permits are issued and all appeals and challenges are complete or the court lifts the stay. The stay is still in effect.

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

Cabinet Gorge Total Dissolved Gas Abatement Plan

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

Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the USFWS listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company evaluated the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. As of the end of 2012, fishway design for Cabinet Gorge was still being finalized. Construction cost estimates and schedules will be developed in 2013. Fishway design for Noxon Rapids has also been initiated, and is still in early stages.

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

Aluminum Recycling Site

In October 2009, the Company (through its subsidiary Pentzer Venture Holdings II, Inc. (Pentzer)) received notice from Ecology proposing to find Pentzer liable for a release of hazardous substances under the Model Toxics Control Act, under Washington state law. Pentzer owns property that adjoins land owned by the Union Pacific Railroad (UPR). UPR leased their property to operators of a facility designated by Ecology as "Aluminum Recycling - Trentwood." Operators of the UPR property maintained piles of aluminum dross, which designate as a state-only dangerous waste in Washington State. In the course of its business, the operators placed a portion of the aluminum dross pile on the property owned by Pentzer. Pentzer does not believe it is a contributor to any environmental contamination associated with the dross pile, and submitted a response to Ecology's proposed findings in November 2009. In December 2009, Pentzer received notice from Ecology that it had been designated as a potentially liable party for any hazardous substances located on this site. UPR completed a Remedial Investigation/Feasibility Study during 2011, which was approved by Ecology in 2012. Based on information currently known to the Company's management, the Company does not expect this issue will have a material effect on its financial condition, results of operations or cash flows.

Collective Bargaining Agreements

The Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represents approximately 45 percent of all of Avista Utilities' employees. The agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the bargaining unit employees expires in March 2014. Two local agreements in Oregon, which cover approximately 50 employees, expire in March 2014.

Other Contingencies

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

The Company routinely assesses, based on studies, expert analyses and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who either have or have not agreed to a settlement as well as recoveries from insurance carriers. The Company's policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred. For matters that affect Avista Utilities' operations, the Company seeks, to the extent appropriate, recovery of incurred costs through the ratemaking process.

The Company has potential liabilities under the Endangered Species Act for species of fish that have either already been added to the endangered species list, listed as "threatened" or petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company. However, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. The state of Montana is examining the status of all water right claims within state boundaries. Claims within the Clark Fork River basin could adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho has initiated adjudication in northern Idaho, which will ultimately include the lower Clark Fork River, the Spokane River and the Coeur d'Alene basin. In addition, the state of Washington has indicated an interest in initiating adjudication for the Spokane River basin in the next several years. The Company is and will continue to be a participant in these adjudication processes. The complexity of such adjudications makes each unlikely to be concluded in the foreseeable future. As such, it is not possible for the Company to estimate the impact of any outcome at this time.

NOTE 22. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2018. The largest of these contracts provides for increases due to changes in the cost of living index and further provides flexibility in the annual obligation from year-to-year subject to a three-year true-up cycle. Total payments under these contracts were as follows for the years ended December 31 (dollars in thousands):

	2012	2011	2010
Information service contract payments	$ 13,221	$ 13,038	$ 13,426

The majority of the costs are included in other operating expenses in the Consolidated Statements of Income. The following table details minimum future contractual commitments for these agreements (dollars in thousands):

	2013	2014	2015	2016	2017	Thereafter	Total
Contractual obligations	$ 11,175	$ 9,400	$ 8,700	$ 8,700	$ 8,600	$ 900	$ 47,475

NOTE 23. AVISTA UTILITIES REGULATORY MATTERS

Regulatory Assets and Liabilities

The following table presents the Company's regulatory assets and liabilities as of December 31, 2012 (dollars in thousands):

	Remaining Amortization Period	Receiving Regulatory Treatment (1) Earning A Return	Receiving Regulatory Treatment Not Earning A Return	(2) Expected Recovery	Total 2012	Total 2011
Regulatory assets:						
Investment in exchange power-net	2019	$ 16,333	$ —	$ —	$ 16,333	$ 18,783
Regulatory assets for deferred income tax	(3)	79,406	—	—	79,406	84,576
Regulatory assets for pensions and other postretirement benefit plans	(4)	—	—	306,408	306,408	260,359
Current regulatory asset for utility derivatives	(5)	—	35,082	—	35,082	69,685
Unamortized debt repurchase costs	(6)	21,635	—	—	21,635	23,037
Regulatory asset for settlement with Coeur d'Alene Tribe	2059	50,509	—	—	50,509	52,463
Demand side management programs	(3)	—	2,579	—	2,579	798
Montana lease payments	(3)	4,059	—	—	4,059	5,096
Lancaster Plant 2010 net costs	2015	3,967	—	—	3,967	5,327
Deferred maintenance costs	2016	—	6,312	—	6,312	—
Regulatory asset for interest rate swaps	2013	—	1,406	—	1,406	18,895
Non-current regulatory asset for utility derivatives	(5)	—	25,218	—	25,218	40,345
Other regulatory assets	(3)	5,053	3,986	4,678	13,717	14,313
Total regulatory assets		$ 180,962	$ 74,583	$ 311,086	$ 566,631	$ 593,677
Regulatory Liabilities:						
Oregon Senate Bill 408	2012	$ —	$ —	$ —	$ —	$ 772
Natural gas deferrals	(3)	6,917	—	—	6,917	12,140
Power deferrals	(3)	27,323	—	—	27,323	13,692
Regulatory liability for utility plant retirement costs	(7)	234,128	—	—	234,128	227,282
Income tax related liabilities	(3)	—	17,206	—	17,206	18,607
Regulatory liability for interest rate swaps	2014-2015	—	7,265	—	7,265	—
Regulatory liability for Spokane Energy	(8)	—	—	21,488	21,488	19,902
Other regulatory liabilities	(3)	2,718	1,598	—	4,316	5,534
Total regulatory liabilities		$ 271,086	$ 26,069	$ 21,488	$ 318,643	$ 297,929

(1) Earning a return includes either interest on the regulatory asset/liability or a return on the investment as a component of rate base at the allowed rate of return.

(2) Expected recovery is pending regulatory treatment including regulatory assets and liabilities that have prior regulatory precedence.

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

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

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

(8) Consists of a regulatory liability recorded for the cumulative retained earnings of Spokane Energy that the Company will flow through regulatory accounting mechanisms in future periods.

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge on the Consolidated Balance Sheets for future prudence review and recovery through retail rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Avista Utilities and the costs included in base retail rates. This difference in net power supply costs primarily results from changes in:

- short-term wholesale market prices and sales and purchase volumes,
- the level of hydroelectric generation,
- the level of thermal generation (including changes in fuel prices), and
- retail loads.

In Washington, the Energy Recovery Mechanism (ERM) allows Avista Utilities to periodically increase or decrease electric rates with UTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual net power supply costs, net of the margin on wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers. In the 2010 Washington general rate case settlement, the parties agreed that there would be no deferrals under the ERM for 2010. Deferrals under the ERM resumed in 2011. Total net deferred power costs under the ERM were a liability of $22.2 million as of December 31, 2012, and this balance represents the customer portion of the deferred power costs. As part of the approved Washington general rate case settlement filed on October 19, 2012 and approved on December 26, 2012, during 2013 a one-year credit of $4.4 million would be returned to electric customers from the existing ERM deferral balance so the net average electric rate increase to customers in 2013 would be 2.0 percent. Additionally, during 2014 a one-year credit of $9.0 million would be returned to electric customers from the then-existing ERM deferral balance, if such funds are available, so the net average electric rate increase to customers effective January 1, 2014 would be 2.0 percent. The credits to customers from the ERM balances would not impact the Company's net income.

Under the ERM, the Company absorbs the cost or receives 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. 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 ratio when actual power supply expenses are higher (surcharge to customers) than the amount included in base retail rates within this band. There is a 75 percent customers/25 percent Company sharing ratio when actual power supply expenses are lower (rebate to customers) than the amount included in base retail rates within this band. To the extent that the annual power supply cost variance from the amount included in base rates exceeds $10.0 million, 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
within +/- $0 to $4 million (deadband)	0%	100%
higher by $4 million to $10 million	50%	50%
lower by $4 million to $10 million	75%	25%
higher or lower by over $10 million	90%	10%

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

Avista Utilities has a Power Cost Adjustment (PCA) mechanism in Idaho that allows it to modify electric rates on October 1 of each year with Idaho Public Utilities Commission (IPUC) approval. Under the PCA mechanism, Avista Utilities defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers. These annual October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a regulatory liability of $5.1 million as of December 31, 2012 and $0.7 million as of December 31, 2011.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Utilities files a purchased gas cost adjustment (PGA) in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. These annual PGA filings in Washington and Idaho provide for the deferral, and recovery or refund, of 100 percent of the difference between actual and estimated commodity and pipeline transportation costs, subject to applicable regulatory review. The annual PGA filing in Oregon provides for deferral, and recovery or refund, of 100 percent of the difference between actual and estimated pipeline transportation costs and commodity costs that are fixed through hedge transactions. Commodity costs that are not hedged for Oregon customers are subject to a sharing mechanism whereby Avista Utilities defers, and recovers or refunds, 90 percent of the difference between these actual and estimated costs. Total net deferred natural gas costs to be refunded to customers were a liability of $6.9 million as of December 31, 2012 and $12.1 million as of December 31, 2011.

Washington General Rate Cases

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

In December 2011, the UTC approved a settlement agreement in the Company's electric and natural gas general rate cases filed in May 2011. As agreed to in the settlement agreement, base electric rates for the Company's Washington customers increased by an average of 4.6 percent, which is designed to increase annual revenues by $20.0 million. Base natural gas rates for the Company's Washington customers increased by an average of 2.4 percent, which is designed to increase annual revenues by $3.75 million. The new electric and natural gas rates became effective on January 1, 2012.

As part of the settlement agreement, the Company agreed to not file a general rate case in Washington prior to April 1, 2012.

The settlement agreement also provides for the deferral of certain generation plant maintenance costs. In order to address the variability in year-to-year maintenance costs, beginning in 2011, the Company is deferring changes in maintenance costs related to its Coyote Spring 2 natural gas-fired generation plant and its 15 percent ownership interest in Units 3 & 4 of the Colstrip generation plant. The Company compares actual, non-fuel, maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of baseline maintenance expenses used to establish base retail rates, and defers the difference. The deferral occurred annually, with no carrying charge, with deferred costs being amortized over a four-year period, beginning in January of the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases would be the actual maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. Total net deferred costs under this mechanism in Washington were a regulatory asset of $4.0 million as of December 31, 2012 compared to a regulatory liability of $0.5 million as of December 31, 2011.

As part of the settlement agreement in October 2012 to the Company's latest general rate case discussed in further detail below, the parties have agreed that the maintenance cost deferral mechanism on these generation plants will terminate on December 31, 2012, with the four-year amortization of the 2011 and 2012 deferrals to conclude in 2015 and 2016, respectively.

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

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

The UTC order approving the settlement agreement included certain conditions. The new retail rates to become effective January 1, 2014 will be temporary rates, and on January 1, 2015 electric and natural gas base rates will revert back to 2013 levels absent any intervening action from the UTC. The settlement agreement also states that the Company will not file a general rate case in Washington that would cause an increase in base retail rates before January 1, 2015. The Company could, however, make a filing prior to January 2015, but new rates resulting from the filing would not take effect prior to January 1, 2015. This does not preclude the Company from filing annual rate adjustments such as the PGA.

In addition, in its Order, the UTC found that much of the approved base rate increases are justified by the planned capital expenditures necessary to upgrade and maintain the Company's utility facilities. If these capital projects are not completed to a level that was contemplated in the original settlement agreement, this could result in base rates which are considered too high by the UTC. As a result, Avista Corp. must file capital expenditure progress reports with the UTC on a periodic basis so that the UTC can monitor the capital expenditures and ensure they are in line with those contemplated in the settlement agreement.

The settlement agreement provides for an authorized return on equity of 9.8 percent and an equity ratio of 47.0 percent, resulting in an overall return on rate base of 7.64 percent.

Idaho General Rate Cases

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

The 2010 settlement agreement includes a rate mitigation plan under which the impact on customers of the new rates will be reduced by amortizing $11.1 million ($17.5 million when grossed up for income taxes and other revenue-related items) of previously deferred state income taxes over a two-year period as a credit to customers. While the Company’s cash collections from customers will be reduced by this amortization during the two-year period, the mitigation plan will have no impact on the Company’s net income. Retail rates increased on October 1, 2011 and will increase on October 1, 2012 as the deferred state income tax balance is amortized.

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

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

The settlement agreement also provides for the deferral of certain generation plant operation and maintenance costs. In order to address the variability in year-to-year operation and maintenance costs, beginning in 2011, the Company is deferring changes in operation and maintenance costs related to the Coyote Spring 2 natural gas-fired generation plant and its 15 percent ownership interest in Units 3 & 4 of the Colstrip generation plant. The Company compares actual, non-fuel, operation and maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of expenses authorized for recovery in base rates in the applicable deferral year, and defers the difference from that currently authorized. The deferral occurs annually, with no carrying charge, with deferred costs being amortized over a three-year period, beginning in January of the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases will be the actual operation and maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. Total net deferred costs under this mechanism in Idaho were regulatory assets of $2.3 million as of December 31, 2012 and $0.1 million as of December 31, 2011.

On October 11, 2012, the Company filed electric and natural gas general rate cases with the IPUC. The Company requested an overall increase in electric rates of 4.6 percent and an overall increase in natural gas rates of 7.2 percent. The filings were designed to increase annual electric revenues by $11.4 million and increase annual natural gas revenues by $4.6 million. The Company's requests were based on a proposed overall rate of return of 8.46 percent, with a common equity ratio of 50 percent and a 10.9 percent return on equity.

On February 6, 2013, Avista Corp. and certain other parties filed a settlement agreement with the IPUC with respect to Avista Corp.'s electric and natural gas general rate cases. Parties to the settlement agreement include the staff of the IPUC, Clearwater Paper Corporation, Idaho Forest Group, LLC, the Idaho Conservation League, and the Company. Community Action Partnership Association of Idaho (CAPAI), a low-income customer advocacy group, and the Snake River Alliance did not join in the settlement agreement. However, on February 20, 2013 the Snake River Alliance provided a letter to the IPUC supporting the settlement agreement. This settlement agreement is subject to approval by the IPUC and would conclude the proceedings related the general rate requests filed by the Company on October 11, 2012. New rates would be implemented in two phases: April 1, 2013 and October 1, 2013.

The settlement agreement proposes that, effective April 1, 2013, Avista Corp. would be authorized to implement a base rate increase for Idaho natural gas customers of 4.9 percent (designed to increase annual revenues by $3.1 million). There would be no change in base electric rates on April 1, 2013. However, the settlement agreement would provide for the recovery of the costs of the Palouse Wind Project through the Power Cost Adjustment mechanism beginning April 1, 2013.

The settlement agreement also proposes that, effective October 1, 2013, Avista Corp. would be authorized to implement a base rate increase for Idaho natural gas customers of 2.0 percent (designed to increase annual revenues by $1.3 million). A credit resulting from deferred natural gas costs of $1.6 million would be returned to the Company's Idaho natural gas customers from October 1, 2013 through December 31, 2014, so the net annual average natural gas rate increase to natural gas customers effective October 1, 2013 would be 0.3 percent.

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

The $1.6 million credit to Idaho natural gas customers and the $3.9 million credit to Idaho electric customers would not impact the Company's net income.

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

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

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

Oregon General Rate Cases

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

On January 1, 2013, Avista Corp. purchased the Klamath Falls Lateral (Lateral), a 15-mile, 6-inch natural gas transmission pipeline from Williams Northwest Pipeline (Williams). The Klamath Falls Lateral interconnects with another interstate pipeline, Gas Transmission Northwest, to transport natural gas to serve Avista Corp.'s customers in Klamath Falls, Oregon. The purchase price was approximately $2.3 million and will save Oregon customers approximately $1.4 million annually as Avista Corp. will be able to reduce its contracted natural gas transportation requirements from Williams. In Order No. 12-429, the OPUC approved the Company's request to recover from customers the revenue requirement associated with the purchase of the Lateral, which is approximately $0.5 million annually. This approval will provide a return of and a return on Avista Corp.'s investment in the lateral. While the OPUC approved the recovery of the revenue requirement, it will not determine whether the purchase of the Lateral was prudent until the Company's next Oregon general rate case.

NOTE 24. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. The Company's management evaluates performance based on income (loss) from operations before income taxes as well as net income (loss) attributable to Avista Corp. shareholders. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. Avista Utilities' business is managed based on the total regulated utility operation. Ecova is a provider of facility information and cost management services for multi-site customers throughout North America. The Other category, which is not a reportable segment, includes Spokane Energy, other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital. The following table presents information for each of the Company’s business segments (dollars in thousands):

	Avista Utilities	Ecova	Other	Total Non-Utility	Intersegment Eliminations (1)	Total
For the year ended December 31, 2012:						
Operating revenues	$ 1,354,185	$ 155,664	$ 38,953	$ 194,617	$ (1,800)	$ 1,547,002
Resource costs	693,127	—	—	—	—	693,127
Other operating expenses (3)	276,780	139,173	39,841	179,014	(1,800)	453,994
Depreciation and amortization	112,091	13,519	792	14,311	—	126,402
Income from operations (3)	188,778	2,972	(1,680)	1,292	—	190,070
Interest expense (2)	72,552	1,790	3,437	5,227	(344)	77,435
Income taxes	42,842	1,497	(3,078)	(1,581)	—	41,261
Net income (loss) attributable to Avista Corporation shareholders	81,704	1,825	(5,319)	(3,494)	—	78,210
Capital expenditures	271,187	4,121	666	4,787	—	275,974
For the year ended December 31, 2011:						
Operating revenues	$ 1,443,322	$ 137,848	$ 40,410	$ 178,258	$ (1,800)	$ 1,619,780
Resource costs	790,048	—	—	—	—	790,048
Other operating expenses (3)	261,926	109,738	34,917	144,655	(1,800)	404,781
Depreciation and amortization	105,629	7,193	778	7,971	—	113,600
Income from operations (3)	202,373	20,917	4,714	25,631	—	228,004
Interest expense (2)	69,347	305	4,943	5,248	(387)	74,208
Income taxes	48,964	7,852	(184)	7,668	—	56,632
Net income (loss) attributable to Avista Corporation shareholders	90,902	9,671	(349)	9,322	—	100,224
Capital expenditures	239,782	2,998	592	3,590	—	243,372
For the year ended December 31, 2010:						
Operating revenues	$ 1,419,646	$ 102,035	$ 61,067	$ 163,102	$ (24,008)	$ 1,558,740
Resource costs	795,075	—	—	—	—	795,075
Other operating expenses (3)	252,437	80,100	54,394	134,494	(24,008)	362,923
Depreciation and amortization	100,554	6,070	1,002	7,072	—	107,626
Income from operations (3)	198,200	15,865	5,669	21,534	—	219,734
Interest expense (2)	70,867	276	5,530	5,806	(249)	76,424
Income taxes	46,428	5,679	(950)	4,729	—	51,157
Net income (loss) attributable to Avista Corporation shareholders	86,681	7,433	(1,689)	5,744	—	92,425
Capital expenditures	202,227	1,932	497	2,429	—	204,656
Total Assets:						
As of December 31, 2012	$ 3,894,821	$ 322,720	$ 95,638	$ 418,358	$ —	$ 4,313,179
As of December 31, 2011	$ 3,809,446	$ 292,940	$ 112,145	$ 405,085	$ —	$ 4,214,531

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

(2) Including interest expense to affiliated trusts.

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

NOTE 25. SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

The Company's energy operations are significantly affected by weather conditions. Consequently, there can be large variances in revenues, expenses and net income between quarters based on seasonal factors such as, but not limited to, temperatures and streamflow conditions. A summary of quarterly operations (in thousands, except per share amounts) for 2012 and 2011 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2012				
Operating revenues	$ 452,257	$ 343,585	$ 340,632	$ 410,528
Operating expenses (1)	375,863	297,565	314,023	369,481
Income from operations (1)	$ 76,394	$ 46,020	$ 26,609	$ 41,047
Net income	$ 38,213	$ 18,532	$ 5,962	$ 16,093
Net loss (income) attributable to noncontrolling interests	175	(354)	(176)	(235)
Net income attributable to Avista Corporation shareholders	$ 38,388	$ 18,178	$ 5,786	$ 15,858
Outstanding common stock:				
Weighted average, basic	58,581	58,702	59,047	59,774
Weighted average, diluted	58,950	58,924	59,123	59,826
Earnings per common share attributable to Avista Corporation shareholders, diluted	$ 0.65	$ 0.31	$ 0.10	$ 0.26
2011				
Operating revenues	$ 476,586	$ 360,557	$ 343,710	$ 438,927
Operating expenses (1)	394,192	306,917	310,064	380,603
Income from operations (1)	$ 82,394	$ 53,640	$ 33,646	$ 58,324
Net income	$ 42,403	$ 23,528	$ 11,637	$ 25,971
Net income attributable to noncontrolling interests	(485)	(527)	(935)	(1,368)
Net income attributable to Avista Corporation shareholders	$ 41,918	$ 23,001	$ 10,702	$ 24,603
Outstanding common stock:				
Weighted average, basic	57,342	57,787	58,057	58,304
Weighted average, diluted	57,414	58,143	58,232	58,583
Earnings per common share attributable to Avista Corporation shareholders, diluted	$ 0.73	$ 0.39	$ 0.18	$ 0.42

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

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, 2012.

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, 2012 is effective at a reasonable assurance level.

The Company's independent registered public accounting firm, Deloitte & Touche LLP, has issued an attest report on the Company's internal control over financial reporting as of December 31, 2012.

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, 2012, 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, 2012, 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, 2012 of the Company and our report dated February 26, 2013 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 26, 2013

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this Item (other than the information regarding executive officers and the Company's Code of Business Conduct and Ethics set forth below) is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 9, 2013, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 30, 2012, relating to its Annual Meeting of Shareholders held on May 10, 2012.

Executive Officers of the Registrant

Name	Age	Business Experience
Scott L. Morris	55	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	49	Treasurer since January 2013; Senior Vice President and Chief Financial Officer (Principal Financial Officer) since September 2008; prior to employment with the Company held the following positions with Black Hills Corporation: Executive Vice President and Chief Financial Officer March 2003 to January 2008; Senior Vice President and Chief Financial Officer March 2000 to March 2003; Controller May 1997 to March 2000.
Marian M. Durkin	59	Senior Vice President, General Counsel and Chief Compliance Officer since November 2005; Senior Vice President and General Counsel August 2005 – November 2005; prior to employment with the Company: held several legal positions with United Air Lines, Inc. from 1995 to August 2005, most recently served as Vice President Deputy General Counsel and Assistant Secretary.
Karen S. Feltes	57	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	51	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	56	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	54	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	57	Vice President since May 2004; Vice President of Operations - Avista Utilities since June 2012; Vice President of Customer Solutions – Avista Utilities April 2011 - December 2012; Vice President of Transmission and Distribution Operations – Avista Utilities May 2004 – April 2011; various other management and staff positions with the Company and its subsidiaries since 1979.
David J. Meyer	59	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	54	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.
Jason R. Thackston	42	Vice President of Energy Resources since December 2012; Vice President of Customer Solutions – Avista Utilities June 2012 - December 2012; Vice President of Energy Delivery April 2011 – December 2012; Vice President of Finance June 2009 – April 2011; various other management and staff positions with the Company since 1996.
Roger D. Woodworth	56	Vice President since November 1998; Vice President and Chief Strategy Officer since April 2011; Vice President, Sustainable Energy Solutions Avista Utilities February 2007 – April 2011; Vice President, Customer Solutions for Avista Utilities March 2003 – February 2007; Vice President of Utility Operations of Avista Utilities September 2001 – March 2003; Vice President – Corporate Development November 1998 – September 2001; various other management and staff positions with the Company since 1979.

All of the Company's executive officers, with the exception of James M. Kensok, Don F. Kopczynski, David J. Meyer, and Kelly O. Norwood, were officers or directors of one or more of the Company's subsidiaries in 2012. 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

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 9, 2013, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 30, 2012, relating to its Annual Meeting of Shareholders held on May 10, 2012.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

(a) Security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities):

Information regarding security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities) has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 9, 2013.

(b) Security ownership of management:

The information required by this Item regarding the security ownership of management is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 9, 2013, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 30, 2012, relating to its Annual Meeting of Shareholders held on May 10, 2012.

(c) Changes in control:

None.

(d) Securities authorized for issuance under equity compensation plans as of December 31, 2012:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(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))
	(1)		
Equity compensation plans approved by security holders (2)	3,000	$ 12.41	740,747

(1) Excludes unvested restricted shares and performance share awards granted under Avista Corp.'s Long Term Incentive Plan. At December 31, 2012, 117,118 Restricted Share awards were outstanding. Performance share awards may be paid out at zero shares at a minimum achievement level; 359,700 shares at target level; or 719,400 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.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 9, 2013, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 30, 2012, relating to its Annual Meeting of Shareholders held on May 10, 2012.

Item 14. Principal Accounting Fees and Services

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 9, 2013, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 30, 2012, relating to its Annual Meeting of Shareholders held on May 10, 2012.

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, 2012, 2011 and 2010

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2012, 2011 and 2010

Consolidated Balance Sheets as of December 31, 2012 and 2011

Consolidated Statements of Cash Flows for the Years Ended December 31, 2012, 2011 and 2010

Consolidated Statements of Equity and Redeemable Noncontrolling Interests for the Years Ended December 31, 2012, 2011 and 2010

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules:

None

(a) 3. Exhibits:

Reference is made to the Exhibit Index commencing on page 133. 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, 2013	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, 2013
/s/ Mark T. Thies Mark T. Thies (Senior Vice President, Chief Financial Officer, and Treasurer)	Principal Financial Officer	February 26, 2013
/s/ Christy M. Burmeister-Smith Christy M. Burmeister-Smith (Vice President, Controller and Principal Accounting Officer)	Principal Accounting Officer	February 26, 2013
/s/ Erik J. Anderson Erik J. Anderson	Director	February 26, 2013
/s/ Kristianne Blake Kristianne Blake	Director	February 26, 2013
/s/ Donald C. Burke Donald C. Burke	Director	February 26, 2013
/s/ Rick R. Holley Rick R. Holley	Director	February 26, 2013
/s/ John F. Kelly John F. Kelly	Director	February 26, 2013
/s/ Rebecca A. Klein Rebecca A. Klein	Director	February 26, 2013
/s/ Michael L. Noël Michael L. Noël	Director	February 26, 2013

AVISTA CORPORATION

/s/ Marc F. Racicot Marc F. Racicot	Director	February 26, 2013
/s/ Heidi B. Stanley Heidi B. Stanley	Director	February 26, 2013
/s/ R. John Taylor R. John Taylor	Director	February 26, 2013

EXHIBIT INDEX

	Previously Filed(1)		
Exhibit	With Registration Number	As Exhibit	
3.1	1-3701 (with June 30, 2012 Form 10-Q)	3.1	Restated Articles of Incorporation of Avista Corporation, as amended and restated June 6, 2012.
3.2	1-3701 (with Form 8-K dated as of August 12, 2011)	3.2	Bylaws of Avista Corporation, as amended August 12, 2011.
4.1	2-4077	B-3	Mortgage and Deed of Trust, dated as of June 1, 1939.
4.2	2-9812	4(c)	First Supplemental Indenture, dated as of October 1, 1952.
4.3	2-60728	2(b)-2	Second Supplemental Indenture, dated as of May 1, 1953.
4.4	2-13421	4(b)-3	Third Supplemental Indenture, dated as of December 1, 1955.
4.5	2-13421	4(b)-4	Fourth Supplemental Indenture, dated as of March 15, 1967.
4.6	2-60728	2(b)-5	Fifth Supplemental Indenture, dated as of July 1, 1957.
4.7	2-60728	2(b)-6	Sixth Supplemental Indenture, dated as of January 1, 1958.
4.8	2-60728	2(b)-7	Seventh Supplemental Indenture, dated as of August 1, 1958.
4.9	2-60728	2(b)-8	Eighth Supplemental Indenture, dated as of January 1, 1959.
4.10	2-60728	2(b)-9	Ninth Supplemental Indenture, dated as of January 1, 1960.
4.11	2-60728	2(b)-10	Tenth Supplemental Indenture, dated as of April 1, 1964.
4.12	2-60728	2(b)-11	Eleventh Supplemental Indenture, dated as of March 1, 1965.
4.13	2-60728	2(b)-12	Twelfth Supplemental Indenture, dated as of May 1, 1966.
4.14	2-60728	2(b)-13	Thirteenth Supplemental Indenture, dated as of August 1, 1966.
4.15	2-60728	2(b)-14	Fourteenth Supplemental Indenture, dated as of April 1, 1970.
4.16	2-60728	2(b)-15	Fifteenth Supplemental Indenture, dated as of May 1, 1973.
4.17	2-60728	2(b)-16	Sixteenth Supplemental Indenture, dated as of February 1, 1975.
4.18	2-60728	2(b)-17	Seventeenth Supplemental Indenture, dated as of November 1, 1976.
4.19	2-69080	2(b)-18	Eighteenth Supplemental Indenture, dated as of June 1, 1980.
4.20	1-3701 (with 1980 Form 10-K)	4(a)-20	Nineteenth Supplemental Indenture, dated as of January 1, 1981.
4.21	2-79571	4(a)-21	Twentieth Supplemental Indenture, dated as of August 1, 1982.
4.22	1-3701 (with Form 8-K dated September 20, 1983)	4(a)-22	Twenty-First Supplemental Indenture, dated as of September 1, 1983.
4.23	2-94816	4(a)-23	Twenty-Second Supplemental Indenture, dated as of March 1, 1984.

EXHIBIT INDEX

	Previously Filed(1)		
Exhibit	With Registration Number	As Exhibit	
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 Form 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 Form 10-Q)	4(f)	Thirty-Second Supplemental Indenture, dated as of September 1, 2003.
4.34	333-64652	4(a)33	Thirty-Third Supplemental Indenture, dated as of May 1, 2004.
4.35	1-3701 (with Form 8-K dated as of December 15, 2004)	4.1	Thirty-Fourth Supplemental Indenture, dated as of November 1, 2004.
4.36	1-3701 (with Form 8-K dated as of December 15, 2004)	4.2	Thirty-Fifth Supplemental Indenture, dated as of December 1, 2004.
4.37	1-3701 (with Form 8-K dated as of December 15, 2004)	4.3	Thirty-Sixth Supplemental Indenture, dated as of December 1, 2004.
4.38	1-3701 (with Form 8-K dated as of December 15, 2004)	4.4	Thirty-Seventh Supplemental Indenture, dated as of December 1, 2004.
4.39	1-3701 (with Form 8-K dated as of May 12, 2005)	4.1	Thirty-Eighth Supplemental Indenture, dated as of May 1, 2005.
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.

EXHIBIT INDEX

Exhibit	Previously Filed(1) With Registration Number	As Exhibit	
4.41	1-3701 (with Form 8-K dated as of April 6, 2006)	4.1	Fortieth Supplemental Indenture, dated as of April 1, 2006.
4.42	1-3701 (with Form 8-K dated as of December 15, 2006)	4.1	Forty-First Supplemental Indenture, dated as of December 1, 2006.
4.43	1-3701 (with Form 8-K dated as of April 3, 2008)	4.1	Forty-Second Supplemental Indenture, dated as of April 1, 2008.
4.44	1-3701 (with Form 8-K dated as of November 26, 2008)	4.1	Forty-Third Supplemental Indenture, dated as of November 1, 2008.
4.45	1-3701 (with Form 8-K dated as of December 16, 2008)	4.1	Forty-Fourth Supplemental Indenture, dated as of December 1, 2008.
4.46	1-3701 (with Form 8-K dated as of December 30, 2008)	4.3	Forty-Fifth Supplemental Indenture, dated as of December 1, 2008.
4.47	1-3701 (with Form 8-K dated as of September 15, 2009)	4.1	Forty-Sixth Supplemental Indenture, dated as of September 1, 2009.
4.48	1-3701 (with Form 8-K dated as of November 25, 2009)	4.1	Forty-Seventh Supplemental Indenture, dated as of November 1, 2009.
4.49	1-3701 (with Form 8-K dated as of December 15, 2010)	4.5	Forty-Eighth Supplemental Indenture, dated as of December 1, 2010.
4.50	1-3701 (with Form 8-K dated as of December 20, 2010)	4.1	Forty-Ninth Supplemental Indenture, dated as of December 1, 2010.
4.51	1-3701 (with Form 8-K dated as of December 30, 2010)	4.1	Fiftieth Supplemental Indenture, dated as of December 1, 2010.
4.52	1-3701 (with Form 8-K dated as of February 11, 2011)	4.1	Fifty-First Supplemental Indenture, dated as of February 1, 2011.
4.53	1-3701 (with Form 8-K dated as of August 16, 2011)	4.1	Fifty-Second Supplemental Indenture, dated as of August 1, 2011.

EXHIBIT INDEX

	Previously Filed(1)		
Exhibit	With Registration Number	As Exhibit	
4.54	1-3701 (with Form 8-K dated as of December 14, 2011)	4.1	Fifty-Third Supplemental Indenture, dated as of December 1, 2011.
4.55	1-3701 (with Form 8-K dated as of November 30, 2012)	4.1	Fifty-Fourth Supplemental Indenture, dated as of November 1, 2012.
4.56	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.
4.57	333-82165	4(a)	Indenture dated as of April 1, 1998 between Avista Corporation and The Bank of New York, as Successor Trustee.
4.58	1-3701 (with Form 8-K dated as of December 15, 2010)	4.1	Loan Agreement between City of Forsyth, Montana and Avista Corporation $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A dated as of December 1, 2010.
4.59	1-3701 (with Form 8-K dated as of December 15, 2010)	4.3	Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A, dated as of December 1, 2010.
4.60	1-3701 (with Form 8-K dated as of December 15, 2010)	4.2	Loan Agreement between City of Forsyth, Montana and Avista Corporation $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B dated as of December 1, 2010.
4.61	1-3701 (with Form 8-K dated as of December 15, 2010)	4.4	Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B, dated as of December 1, 2010.
10.1	1-3701 (with Form 8-K dated as of February 11, 2011)	10.1	Credit Agreement, dated as of February 11, 2011, among Avista Corporation, the Banks Party hereto, The Bank of New York Mellon, Keybank National Association, and U.S. Bank National Association, as Co-Documentation Agents, Wells Fargo Bank National Association as Syndication Agent and an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.
10.2	1-3701 (with Form 8-K dated as of February 11, 2011)	10.2	Bond Delivery Agreement, dated as of February 11, 2011, between Avista Corporation and Union Bank, N.A.
10.3	1-3701 (with Form 8-K dated as of December 14, 2011)	10.1	First Amendment and Waiver Thereunder, dated as of December 14, 2011, to the Credit Agreement dated as of February 11, 2011, among Avista Corporation, the Banks Party hereto, Wells Fargo Bank National Association as an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.

EXHIBIT INDEX

	Previously Filed[1]		
Exhibit	With Registration Number	As Exhibit	
10.4	1-3701 (with 2002 Form 10-K)	10(b)-3	Priest Rapids Project Product Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.5	1-3701 (with 2002 Form 10-K)	10(b)-4	Priest Rapids Project Reasonable Portion Power Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.6	1-3701 (with 2002 Form 10-K)	10(b)-5	Additional Product Sales Agreement (Priest Rapids Project) executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.7	2-60728	5(g)	Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.
10.8	2-60728	5(g)-1	Amendment to Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.
10.9	2-60728	5(h)	Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.
10.10	2-60728	5(h)-1	Amendment to Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.
10.11	1-3701 (with September 30, 1985 Form 10-Q)	1	Settlement Agreement and Covenant Not to Sue executed by the United States Department of Energy acting by and through the Bonneville Power Administration and the Company, dated as of September 17, 1985, describing the settlement of Project 3 litigation.
10.12	1-3701 (with 1981 Form 10-K)	10(s)-7	Ownership and Operation Agreement for Colstrip Units No. 3 and 4, dated as of May 6, 1981.
10.13	1-3701 (with 1992 Form 10-K)	10(s)-1	Agreements for Purchase and Sale of Firm Capacity between the Company and Portland General Electric Company dated March and June 1992.
10.14	1-3701 (with 2003 Form 10-K)	10(l)	Power Purchase and Sale Agreement between Avista Corporation and Potlatch Corporation, dated as of July 22, 2003.

EXHIBIT INDEX

	Previously Filed(1)		
Exhibit	With Registration Number	As Exhibit	
10.15	1-3701 (with 2011 Form 10-K)	10.15	Avista Corporation Executive Deferral Plan. (3)
10.16	1-3701 (with 2011 Form 10-K)	10.16	Avista Corporation Executive Deferral Plan. (3)(8)
10.17	1-3701 (with 2011 Form 10-K)	10.17	Avista Corporation Supplemental Executive Retirement Plan. (3)(8)
10.18	1-3701 (with 2011 Form 10-K)	10.18	Avista Corporation Supplemental Executive Retirement Plan. (3)(8)
10.19	1-3701 (with 1992 Form 10-K)	10(t)-11	The Company's Unfunded Supplemental Executive Disability Plan. (3)
10.20	1-3701 (with 2007 Form 10-K)	10.34	Income Continuation Plan of the Company. (3)
10.21	1-3701 (with 2010 Definitive Proxy Statement filed March 31, 2010)	Appendix A	Avista Corporation Long-Term Incentive Plan. (3)
10.22	1-3701 (with 2010 Form 10-K)	10.23	Avista Corporation Performance Award Plan Summary. (3)(9)
10.23	1-3701 (with 2010 Form 10-K)	10.24	Avista Corporation Performance Award Agreement. (3)(9)
10.24	1-3701 (with 2011 Form 10-K)	10.24	Avista Corporation Performance Award Agreement. (3)(10)
10.25	(2)		Avista Corporation Performance Award Agreement. (3)(11)
10.26	1-3701 (with Form 8-K dated June 21, 2005)	10.1	Employment Agreement between the Company and Marian Durkin in the form of a Letter of Employment. (3)
10.27	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)
10.28	333-47290	99.1	Non-Officer Employee Long-Term Incentive Plan.
10.29	1-3701 (with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. (3)(5)
10.30	1-3701 (with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. (3)(6)
10.31	1-3701 (with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. (3)(7)
10.32	1-3701 (with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. (3)(7)
10.33	(2)		Avista Corporation Non-Employee Director Compensation.
10.34	1-03701 (with May 4, 2012 Form 10-Q)	10.1	Ecova, Inc. (formerly known as Advantage IQ, Inc.) Second Amended and Restated 1997 Stock Plan
12	(2)		Statement Re: computation of ratio of earnings to fixed charges.

EXHIBIT INDEX

	Previously Filed(1)		
Exhibit	With Registration Number	As Exhibit	
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).
101	(2)		The following financial information from the Annual Report on Form 10 K for the period ended December 31, 2012, formatted in XBRL (Extensible Business Reporting Language) and filed electronically herewith: (i) the Consolidated Statements of Income; (ii) Consolidated Statements of Comprehensive Income; (iii) the Consolidated Balance Sheets; (iv) the Consolidated Statements of Cash Flows; (v) the Consolidated Statements of Equity and Redeemable Noncontrolling Interests; and (vi) the Notes to Consolidated Financial Statements.

(1) Incorporated herein by reference.
(2) Filed herewith.
(3) Management contracts or compensatory plans filed as exhibits to this Form 10-K pursuant to Item 15(b).
(4) Furnished herewith.
(5) Applies to Christy M. Burmeister-Smith, Don F. Kopczynski, James M. Kensok, David J. Meyer, Kelly O. Norwood, Jason R. Thackston, Dennis P. Vermillion, and Roger D. Woodworth.
(6) Applies to Marian M. Durkin, Karen S. Feltes, Scott L. Morris, and Mark T. Thies.
(7) Applies to executive officers appointed after October 1, 2010. The Company does not currently have any officers that these agreements apply to.
(8) Applies to executive officers appointed after February 4, 2011. The Company does not currently have any officers that these plans apply to.
(9) Applies to awards in 2010.
(10) Applies to awards in 2011.
(11) Applies to awards in 2012.

AVISTA CORPORATION

PERFORMANCE AWARD AGREEMENT

This Performance Award Agreement (the “Agreement”) is made by and between Avista Corporation, a Washington Corporation (the “Company”) and the individual named in section 1 (the “Participant”) and selected by the Avista Corporation Organization and Compensation Committee (the “Plan Administrator”).

WHEREAS, Performance Awards are granted under the May 13, 2010 amended and restated Avista Corporation Long-Term Incentive Plan (the “Plan”). The terms and conditions of the Performance Awards are set forth below and in the Plan, which is incorporated into this Agreement by reference.

NOW, THEREFORE, in consideration of the premises contained herein and in the Plan, it is agreed as follows:

1. **Terms of Performance Awards**. The terms of the Performance Awards are set forth as follows:

(a) The "Participant" is.

(a) The "Grant Date” is February 2, 2012.

(b) The number of eligible "Performance Awards" shall be **XX** units. “Performance Awards” granted under this Agreement are units that will be reflected in a book account maintained by the Company or a third party administrator during the Performance Cycle, and that will be settled in cash or shares of Avista Corporation Common Stock (“Common Stock”) to the extent provided in this Agreement and the Plan.

(d) The "Performance Cycle" is the period beginning on January 1, 2012 and ending on December 31, 2014.

2. **Grant**. Subject to the terms of this Agreement and the Plan, the Participant is hereby granted the number of Performance Awards as set forth in section 1.

3. **Settlement of Performance Awards**. The Company shall deliver to the Participant one share of Common Stock (or cash equal to the Fair Market Value of one share of Common Stock) for each Performance Award earned by the Participant, as determined in accordance with the provisions of Exhibit 1, which is attached to and forms a part of this Agreement. The earned Performance Award payable to the Participant shall be paid in shares of Common Stock or in cash (based on the Fair Market Value of the Common Stock as of **January 1, 2015** or on the next available trading date, if the designated date is not a trading date), or in a combination of the two, as determined by the Plan Administrator in its sole discretion, except that cash may be distributed in lieu of any fractional share of Common Stock.

All Performance Awards and any Dividend Equivalents (as described in Section 5 below) earned by a Participant under this Agreement are subject to the Recoupment Policy adopted by the Company's Board of Directors as amended from time to time (“Recoupment Policy”). If a Participant becomes subject to the Recoupment Policy any Performance Award and associated Dividend Equivalent may be forfeited in whole or in part and all or part of any distribution payable to a Participant or his or her beneficiary under this Agreement may be recovered by the Company pursuant to the Recoupment Policy.

4. **Time of Payment**. Except as otherwise provided in this Agreement, payment of Performance Awards earned, will be delivered as soon as feasible after the end of the Performance Cycle and after the Plan Administrator certifies the attainment of the performance goals.

5. **Dividend Equivalent Rights**. Any Performance Awards may, in the Plan Administrator's discretion, earn Dividend Equivalent Rights. In respect of any Performance Award that is outstanding on the dividend record date for Common Stock, the Participant may be credited with an amount equal to the cash distributions that would have been paid on the shares of Common Stock covered by such Award had such covered shares been issued and outstanding on such dividend record date. Dividend Equivalent Rights are to be paid in cash based on the total number of Performance Awards earned at the end of the Performance Cycle and delivered as soon as feasible after the

Performance Cycle and after the Plan Administrator certifies the attainment of the performance goals. Dividend Equivalent Rights are subject to all applicable taxes, which are the responsibility of the Participant.

6. **Termination of Employment during Performance Cycle**. Except as otherwise provided in section 7, this section 6 shall apply, if the Participant's employment terminates during a Performance Cycle. If the Participant's employment with the Company and/or Subsidiaries terminates during the Performance Cycle because of Retirement, Disability, or Death, the Participant shall be entitled to a prorated value of the Performance Award earned in accordance with Exhibit 1, determined at the end of the Performance Cycle, and based on the ratio of the number of whole months the Participant was employed during the Performance Cycle to the total number of months in the Performance Cycle (36). If a Participant's employment or services with the Company and/or Subsidiaries terminate on or as of the last day of a performance period, such Participant will be deemed to have terminated after the end of such performance period. If the Participant's employment with the Company and/or Subsidiaries terminates during the Performance Cycle for any reason other than Retirement, Disability, or Death, the Performance Award granted under this Agreement will be forfeited on the Date of Termination (as defined in section 9(b)); provided, however, that in such circumstances, the Plan Administrator, in its sole discretion, may determine that the Participant will be entitled to receive a prorated or other portion of the Performance Award. In case of termination for Cause, the Performance Award granted shall automatically terminate upon first notification to the Participant of such termination, unless the Plan Administrator determines otherwise. If a Participant's employment with the Company is suspended pending an investigation of whether the Participant shall be terminated for Cause, all the Participant's rights under any Award likewise shall be suspended during the period of investigation. The effect of a Company-approved leave of absence on the terms and conditions of an Award shall be determined by the Plan Administrator, in its sole discretion.

7. **Change in Control**. If a Change in Control occurs during the Performance Cycle, and the Participant's Date of Termination (as defined in section 9(b)) does not occur before the Change in Control date, the Participant shall be entitled to a prorated value of the Performance Award that would have been earned by the Participant in accordance with Exhibit 1, determined as of the date of the Change in Control, prorated based on the ratio of the number of whole months the Participant is employed during the Performance Cycle through the date of the Change in Control, to the total number of months in the Performance Cycle; provided, however, that a Payout Factor of at least 100% as set forth in Exhibit 1 for the Performance Cycle shall be deemed to have been achieved as of the date of the Change in Control. Notwithstanding the provisions of sections 3 (with the exception of the application of the Recoupment Policy), 4, and 5, the value of the Performance Award, and any Dividend Equivalent Right, earned in accordance with the foregoing provisions of this section shall be delivered to the Participant in a lump sum cash payment as soon as feasible after the occurrence of a Change in Control, with the value of a Performance Award equal to the Fair Market Value of a share of Common Stock determined under the provision of section 3 as of the date of the Change in Control. Distributions to the Participant under sections 3 and 5 shall not be affected by payments under this section, except that the number of Performance Awards and Dividend Equivalent Rights earned by and payable to the Participant shall be reduced by the number of Performance Awards and Dividend Equivalent Rights with respect to which payment was made to the Participant under this section.

8. **Taxes**. The Participant is liable for any and all taxes, including withholding taxes, arising out of the grant, vesting, payment or settlement of any Performance Awards and Dividend Equivalent Rights. The Company shall have the right to require the Participant to remit to the Company, or to withhold awarded shares of Common Stock, or from any Dividend Equivalent Rights or other amounts due to the Participant, as compensation or otherwise, an amount sufficient to satisfy all federal, state and local withholding tax requirements.

9. **Definitions**. For purposes of this Agreement, the terms used in this Agreement shall be subject to the following:

(a) Change in Control. The term "Change in Control" is defined in section 2.4 of the amended and restated Avista Corp. Long Term Incentive Plan.

(b) Date of Termination. The Participant's "Date of Termination" shall be the first day occurring on or after the Grant Date on which the Participant is not employed by the Company or any Subsidiary, regardless of the reason for the termination of employment; provided that a termination of employment shall not be deemed to occur by reason of a transfer of the Participant between the Company and a Subsidiary or between two Subsidiaries; and further provided that the Participant's employment shall not be considered terminated while the Participant is on a leave of absence from the Company or a Subsidiary approved by the Participant's employer. If, as a result of a sale or other transaction, the Participant's employer ceases to be a Subsidiary (and the Participant's employer is or becomes an entity that is separate from the Company), and the Participant is not, at the end of the 30-day period following the transaction, employed by the Company or an entity that is then a Subsidiary, then the occurrence of such transaction shall be treated as the Participant's Date of Termination caused by the Participant being discharged by the employer.

(c) Disability. "Disability" means "disability" as that term is defined for purposes of the Company's Long Term Disability Plan or other similar successor plan applicable to employees.

(d) Retirement. "Retirement" of the Participant shall mean retirement as of the individual's retirement date under the Retirement Plan for Employees of Avista Corporation or other similar successor plan applicable to employees.

10. **Assignability**. No Performance Award or Dividend Equivalent Right granted or awarded under the Plan may be assigned or transferred by the Participant other than by will or by the applicable laws of descent and distribution, and, during the Participant's lifetime, settlements of such Awards may be payable only to the Participant or a permitted assignee or transferee of the Participant (as provided below). Notwithstanding the foregoing, the Plan Administrator, in its sole discretion, may permit such assignment or transfer and may permit a Participant of such Performance Awards or Dividend Equivalent Rights to designate a beneficiary who may receive compensation settlement under the Award after the Participant's death; provided, however, that any amount so assigned or transferred shall be subject to all the same terms and conditions contained in this Agreement.

11. **General**.

11.1 **Award Agreements**. Performance Awards granted under the Plan shall be evidenced by a written agreement that shall contain such terms, conditions, limitations and restrictions as the Plan Administrator shall deem advisable and that are not inconsistent with the Plan.

11.2 **Continued Employment or Services; Rights in Awards**. Nothing contained in this Agreement, the Plan, or any action of the Plan Administrator taken under the Plan or this Agreement shall be construed as giving any Participant or employee of the Company any right to be retained in the employ of the Company or any Subsidiary or to limit the Company's or any Subsidiary's right to terminate the employment or services of the Participant.

11.3 **Registration**. At the present time, the Company has an effective registration statement with respect to the shares. The Company intends to maintain this registration but has no obligation to do so. In the event that such registration ceases to be effective, the Participant will not receive a Performance Award settlement or payment unless exemptions from registration under federal and state securities laws are available; such exemptions from registration are very limited and might be unavailable. **By accepting the Agreement, the Participant hereby acknowledges that he/she has read the section of the Plan and this Agreement entitled Registration.**

11.4 **No Rights as a Shareholder**. No Award under this agreement shall entitle the Participant to any dividends (except to the extent provided in an award of Dividend Equivalent Rights), voting or any other right of a shareholder unless and until the date of issuance under the Plan of the shares that are the subject of such Performance Award, are free of all applicable restrictions.

11.5 **Compliance with Laws and Regulations**. Notwithstanding anything in the Plan to the contrary, the Board of Directors, in its sole discretion, may bifurcate the Plan so as to restrict, limit or condition the use of any provision of the Plan to Participants who are officers or directors subject to Section 16 of the Exchange Act without so restricting, limiting or conditioning the Plan with respect to other Participants.

11.6 **Severability**. The invalidity or unenforceability of any provision of this Agreement shall not affect the validity and enforceability of any other provision of this Agreement. If any provision of the Agreement is determined to be invalid, illegal or unenforceable in any jurisdiction, or as to any person, or would disqualify any Performance Award under any law deemed applicable by the Plan Administrator, such provision shall be construed or deemed amended by the Plan Administrator to conform to applicable laws, or, if the Plan Administrator determines that the provision cannot be so construed or deemed amended without materially altering the intent of the Plan or the Performance Award, such provision shall be stricken as to such jurisdiction, person or Performance Award, and the remainder of the Agreement and any such Performance Award shall remain in full force and effect.

12. **Administration**. The authority to manage and control the operation and administration of this Agreement shall be vested in the Plan Administrator, and the Plan Administrator shall have all powers with respect to this Agreement as it has with respect to the Plan. Any interpretation of the Agreement by the Plan Administrator and any decision made by it with respect to the Agreement are final and binding.

13. **Construction**. This Agreement is subject to and shall be construed in accordance with the Plan, the terms of which are explicitly made applicable hereto. Unless otherwise defined herein, capitalized terms in this Agreement shall have the same definitions as set forth in the Plan. In the event of any conflict between the provisions hereof and those of the Plan, the provisions of the Plan shall govern.

14. **Amendment**. This Agreement may be amended by written agreement of the Participant and the Company, without the consent of any other person.

15. **Governing Law**. The validity, construction, interpretation and enforceability of this agreement shall be determined and governed by the laws of the State of Washington without giving effect to the principles of conflicts of laws. For the purpose of litigating any dispute that arises under this Agreement, the parties hereby consent to exclusive jurisdiction in Washington State and agree that such litigation shall be conducted in the courts of Spokane County, Washington or the federal courts of the United States.

16. **Successors**. The Company shall require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise to all or substantially all of the business and/or assets of the Company) to agree in writing to assume the Company's obligations under this Agreement and to perform such obligations in the same manner and to the same extent that the Company is required to perform them. As used in this Agreement, “Company” shall mean the Company and any successor to its business and/or assets that assumes and agrees to perform the Company's obligations under the Agreement by operation of law or otherwise.

IN WITNESS WHEREOF, the Participant has executed this Agreement, and the Company has caused these presents to be executed in its name and on its behalf, all as of the Grant Date.

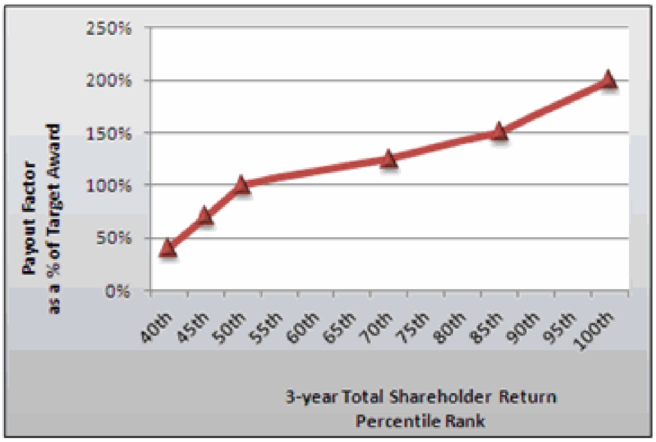
AVISTA CORPORATION

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

EXHIBIT 1

Performance Award Plan
Performance Measures and Goals
2012 - 2014 Performance Cycle

The following graph and table represent the relationship between the Company's relative three-year total shareholder return (TSR) commencing January 1, 2012 and ending December 31, 2014 and the award opportunity. The number of shares delivered at the end of the three-year cycle will range from zero to 200% of the grant. The actual payment depends on Avista's three-year total shareholder return compared to the returns reported in the S&P 400 Utilities Index. To receive 100% of the Award, Avista must perform at the 50th percentile among the S&P 400 Utilities Index. To receive 200% of the Award, Avista must perform at the 100th percentile ranking. If Avista performs below the 40th percentile ranking, no awards or dividend equivalents will be received. Dividend Equivalent Rights are calculated and paid out in cash when and to the extent the performance shares are paid. Awards are interpolated for performance results between the figures shown.



3-year Relative Total Shareholder Return	Payout Factor (% of Target)
100th	200%
85th	150%
70th	125%
50th	100%
45th	70%
40th	40%
< 40th	—%

Total shareholder return reflects stock price appreciation and dividend reinvestment over the three-year period. The calculation assumes that dividends are reinvested on a daily basis. The source for stock price and dividend data is Standard and Poor's Research Insight.

From one year to the next, if S&P drops a company out of the index and adds another, the new company will be included in the ranking and the dropped company will be excluded. When a new company is added, they will be added to the ranking as if they had been in the ranking from the beginning - provided that there is pricing and dividend data at the beginning of the cycle. When a company is dropped everything related to that company will be excluded from the ranking as if the company was never part of the ranking.

Example Formula:
Assuming that the Shares granted were 3,000 and the Total Shareholder Return is ranked at the 45th percentile after the three-year Performance Cycle, then the Participant's final award is 2,100 Shares of Stock plus Dividend Equivalents Rights.

Payout Factor (% of Target)	X	# of Performance Shares Granted to Participant	=	Final # of Performance Shares Awarded to Participant
70%	X	3,000 shares	=	2,100 shares plus Dividends

Percentile Ranking Methodology:
The percentile rank is calculated using the PERCENTRANK function in MS Excel, excluding Avista from the list and rounding all results to the nearest whole percentile.

The calculation can be replicated by arranging the TSR data from highest to lowest for all peers except Avista. A percentile ranking is calculated for each data point assuming 100.0th %ile for the highest data point, 0.0 %ile for the lowest data point, and the corresponding percentile for every other data point with an equal difference in percentile ranking for each data point. The TSR for Avista is calculated by determining Avista's rank in the list and interpolating between the percentile rankings for the companies immediately above and below based on the differences in TSR. An example, based on sample data is as follows:

Company Ranking	TSR	Percentile Rank
1	201.6%	100%
2	135.9%	98.2%
47 (ABC Corp)	20.3%	17.8%
48 (XYZ Corp)	16%	16%
5 6	(3.3)%	1.7%
57	(10.5)%	—%

If a company's TSR is 18.9%, the resulting percentile ranking would be 17%, calculated as follows: 17% = 16.0% + [(18.9% - 16.0%) / (20.3% - 16.0%) * (17.8% - 16.0%)]

Total Shareholder Return (TSR) Methodology:
For purposes of this agreement, a methodology for calculating a total return to shareholder with dividend reinvestment was established. Returns are calculated daily based on stock price changes and dividend payments and then accumulated over the measurement period. Below are additional assumptions used in Avista's calculation for total shareholder return.

General Assumptions:
The starting and ending prices are determined by averaging closing price on the last trading day of November and the last trading day of December.

For example, the stock price for the start of the performance period for Avista is $21.46, the average of $21.54 (12/31/2007) and $21.38 (11/30/2007).

Reinvest dividends on a daily basis.
Use ex-date dividends per share.
Returns will be calculated over the applicable performance period.

Example:

Date	Closing Price	Dividend	Daily TSR
11/23/2007	21.08	—	NA
11/26/2007	20.90	—	(0.8539)%
11/27/2007	21.09	0.15	1.6268%*
11/28/2007	21.54	—	2.1337%
11/29/2007	21.38	—	(0.7428)%
11/30/2007	21.38	—	—%
Cumulative TSR 11/23/2007 to 11/30/2007			2.1347%

* [(21.09 + 0.15) / 20.90] -1

ACCEPTANCE AND ACKNOWLEDGMENT

I, a resident of the state of ___________________________________, accept the Performance Award described in this Agreement and in the Plan, and acknowledge that I have received a copy of this Agreement and the Plan. I have read and understand the Plan, and I hereby make the representations, warranties and acknowledgments, and undertake the indemnity and other obligations, therein specified.

Dated: _________________

___________________________ ____________________________________
Social Security Number Signature of Employee

____
Printed Name

Exhibit 10.33

Avista Corporation
Non-Employee Director Compensation - 2012

Directors who were not employees of the Company received an annual retainer of $116,000, of which a minimum of $48,000 is paid in Company common stock each year. Directors have the option of taking the remaining $68,000 in cash, stock or a combination of both cash and stock. The cash portion of the retainer is paid quarterly. Directors were also paid $1,500 for each meeting of the Board or any Committee meeting of the Board. Directors who served as Board Committee Chairs received an additional $5,000 annual retainer, with the exception of the Audit Committee Chair, who received an additional $10,000 annual retainer. The Lead Director received an additional annual retainer of $15,000.

In addition, any non-employee director who served as director of a subsidiary of the Company received from the Company a $5,000 annual retainer and a meeting fee of $1,500 for each subsidiary Board meeting and Committee meeting the director attended. Directors Anderson, Blake, Burke and Kelly hold Board positions with a subsidiary of the Company.

Each year, the Governance Committee reviews all components of directors' compensation. During 2012, the Governance Committee engaged Meridian Compensation Partners, LLC. (“Meridian”) to assist in this review. The information provided by Meridian is used to compare the Company's current director compensation with peer companies in the utility industry and general industry companies of similar size. The companies comprising the Director Peer Group are those companies in the S&P Utility Mid-Cap, as well as NorthWestern Energy, Northwest Natural Gas Company, and Portland General Electric Company.

At its September 7, 2012 meeting, the Board reviewed survey results from Meridian regarding current pay practices for director compensation. The Board approved an increase in the director's annual retainers from $5,000 to $15,000 for any non-employee director who serves as director of a subsidiary of the Company, and established an annual Chair retainer of $10,000 for any non-employee director who chairs the Audit Committee of a subsidiary of the Company. The Board also approved an increase in the Committee Chair annual retainer for the Company's Compensation Committee Chair from $5,000 to $9,000. These changes were made effective September 15, 2012.

Each director is entitled to reimbursement of reasonable out-of-pocket expenses incurred in connection with meetings of the Board or its Committees and related activities, including director education courses and materials. These expenses include travel to and from the meetings, as well as any expenses they incur while attending the meetings.

The Company has a minimum stock ownership expectation for all Board members. Directors are expected to achieve a minimum investment of $236,000 or 11,000 shares, whichever is less, in Company common stock within four years of their becoming Board members and are expected to retain at least that level of investment during their tenure as Board members. Shares that have previously been deferred under the former Non-Employee Director Stock Plan count for purposes of determining whether a director has achieved the ownership expectation.

The ownership expectation illustrates the Board's philosophy of the importance of stock ownership for directors to further strengthen the commonality of interest between the Board and shareholders. The Governance Committee annually reviews director holdings to determine whether they meet ownership expectations. All directors currently comply based on their years of service completed on the Board.

Exhibit 12

AVISTA CORPORATION

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

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

Exhibit 21

AVISTA CORPORATION

SUBSIDIARIES OF REGISTRANT

Subsidiary	State or Country of Incorporation
Avista Capital, Inc.	Washington
Ecova, Inc.	Washington
Avista Development, Inc.	Washington
Avista Energy, Inc.	Washington
Avista Northwest Resources, LLC	Washington
Pentzer Corporation	Washington
Pentzer Venture Holding II, Inc.	Washington
Bay Area Manufacturing, Inc.	Washington
Advanced Manufacturing and Development, Inc.	California
Avista Capital II	Delaware
Spokane Energy, LLC	Delaware
Steam Plant Square, LLC	Washington
Steam Plant Brew Pub, LLC	Washington
Courtyard Office Center, LLC	Washington

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 2-81697, 2-94816, 033 -54791, 333-03601, 333-22373, 333-33790, 333-47290, 333-126577 and 333-179042 on Form S-8; and in Registration Statement Nos. 333-163609 and 333-177981 on Form S-3 of our reports dated February 26, 2013, relating to the consolidated financial statements of Avista Corporation and subsidiaries (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of Accounting Standards Update No. 2009-17, *Consolidations - Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities*), and the effectiveness of Avista Corporation's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Avista Corporation for the year ended December 31, 2012.

/s/ Deloitte & Touche LLP

Seattle, Washington

February 26, 2013

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, 2013

/s/ Scott L. Morris

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

Exhibit 31.2

CERTIFICATION

I, Mark T. Thies, certify that:

1. I have reviewed this report on Form 10-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, 2013

/s/ Mark T. Thies

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

Exhibit 32

AVISTA CORPORATION

CERTIFICATION OF CORPORATE OFFICERS

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

Sarbanes-Oxley Act of 2002)

Each of the undersigned, Scott L. Morris, Chairman of the Board, President and Chief Executive Officer of Avista Corporation (the "Company"), and Mark T. Thies, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company's Annual Report on Form 10-K for the year ended December 31, 2012 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 26, 2013

/s/ Scott L. Morris

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

/s/ Mark T. Thies

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