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, 2014 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 $2,018,577,718 based on the last reported sale price thereof on the consolidated tape on June 30, 2014.

As of January 31, 2015, 62,344,484 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 7, 2015. Prior to such filing, the Proxy Statement filed in connection with the annual meeting of shareholders held on May 8, 2014.	**Part III, Items 10, 11, 12, 13 and 14**

INDEX

* = not an applicable item in the 2014 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
AEL&P	-	Alaska Electric Light and Power Company, the primary operating subsidiary of AERC
AERC	-	Alaska Energy and Resources Company, a privately-held company based in Juneau, Alaska. The Company entered into an agreement and plan of merger with AERC on November 4, 2013 and the acquisition was completed on July 1, 2014.
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. (not a subsidiary) 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 combined-cycle 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 ERM 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. Ecova was sold on June 30, 2014.
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
GS	-	Generating station
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

Juneau	-	The City and Borough of Juneau, Alaska
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
MPSC	-	Public Service Commission of the State of Montana
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
RCA	-	The Regulatory Commission of Alaska
RTO	-	Regional Transmission Organization
Salix LNG	-	Salix, Inc., a subsidiary of Avista Capital, specializing in small scale liquified natural gas projects, primarily in Western North America.
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. Most of these factors are beyond our control and may have a significant effect on our operations, results of operations, financial condition or cash flows, which 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 both energy demand and electric generating capability, 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 effects 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 and discretion over allowed return on investment;
- volatility and illiquidity in wholesale energy markets, including the availability of willing buyers and sellers, 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 the economy's effects on customer demand for utility services;
- declining energy demand related to customer energy efficiency and/or conservation measures;
- 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;
- political pressures or regulatory practices that could constrain or place additional cost burdens on our energy supply sources, such as campaigns to halt coal-fired power generation and opposition to other thermal generation, wind turbines or hydroelectric facilities;
- changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension and other postretirement benefit plans, which can affect future funding obligations, pension and other postretirement benefit expense and the related liabilities;
- the outcome of pending legal proceedings arising out of the "western energy crisis" of 2000 and 2001, specifically related to the Pacific Northwest refund proceedings;
- the outcome of legal proceedings and other contingencies;

- changes in environmental and endangered species laws, regulations, decisions and policies, including present and potential environmental remediation costs and our compliance with these matters;
- wholesale and retail competition including alternative energy sources, growth in customer-owned power resource technologies that displace utility-supplied energy or that may be sold back to the utility, and alternative energy suppliers and delivery arrangements;
- growth or decline of our customer base and the extent to which new uses for our services may materialize or existing uses may decline;
- 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, avalanches or other incidents that may impair assets and may disrupt operations of any of our generation facilities, transmission and distribution systems or other operations;
- public injuries or damage arising from or allegedly arising from our operations;
- blackouts or disruptions of interconnected transmission systems (the regional power grid);
- disruption to information systems, automated controls and other technologies that we rely on for our operations, communications and customer service;
- terrorist attacks, cyber attacks or other malicious acts that may disrupt or cause damage to our utility assets or to the national economy in general, including any effects of terrorism, cyber attacks or vandalism that damage or disrupt information technology systems;
- cyber attacks or other potential lapses that result in unauthorized disclosure of private information, which could result in liabilities against us, costs to investigate, remediate and defend, and damage to our reputation;
- 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 global and our utilities' service area climates, 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 or disruptions to the supply chain;
- 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 restrictive covenants in our financing arrangements and wholesale energy contracts;
- increasing health care costs and the resulting effect on employee injury costs and health insurance provided to our employees and retirees;
- increasing costs of insurance, more restrictive coverage terms and our ability to obtain insurance;
- work force issues, including changes in collective bargaining unit agreements, strikes, work stoppages, 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 interest rates that affect borrowing costs, our ability to effectively hedge interest rates for anticipated debt issuances, variable interest rate borrowing and the extent that we recover interest costs through utility operations;

- potential difficulties 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;
- 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 and the extent of our business development efforts where potential future business is uncertain;
- compliance with extensive federal, state and local legislation and regulation, including numerous environmental, health, safety and other laws and regulations that affect our operations and costs;
- our ability to fully collect the indemnification escrow amounts because of information that was covered under management's representations and warranties related to the Ecova sale which could be inaccurate or incomplete at the time of sale, or because of new information which could be identified subsequent to the sale date, and
- adverse impacts to our Alaska operations because a majority of the hydroelectric power generation for such operations is provided by a single facility that is subject to a long-term power purchase agreement; hence any issues that negatively affect this facility's ability to generate or transmit power, the cost and ability to replace power in the event of an extended outage, any decrease in the demand for the power generated by this facility or any loss by our subsidiary of its contractual rights with respect thereto or other adverse effect thereon could negatively affect our Alaska operations' financial results.

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 territory of Washington in 1889, is primarily an electric and natural gas utility with certain other business ventures. As of December 31, 2014, we employed 1,658 people in our primary utility operations (Avista Utilities) and 216 people in our subsidiary businesses. 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 natural gas utility operations also include separate service areas in parts of Oregon. Through our subsidiary Alaska Electric Light and Power Company, we also provide electric services in the City and Borough of Juneau (Juneau), Alaska.

As of December 31, 2014, we have two reportable business segments as follows:

- **Avista Utilities** – an operating division of Avista Corp. (not a subsidiary) that comprises our regulated utility operations in the Pacific Northwest. Avista Utilities generates, transmits and distributes electricity and distributes natural gas, serving electric and gas customers in eastern Washington and northern Idaho and gas customers in parts of Oregon. We also supply electricity to a small number of customers in Montana, most of whom are employees who operate our Noxon Rapids generating facility. Avista Utilities also engages in wholesale purchases and sales of electricity and natural gas.
- **Alaska Electric Light and Power Company** - the primary operating subsidiary of Alaska Energy and Resources Company (AERC), which provides electric services in the City and Borough of Juneau, Alaska. We completed our acquisition of AERC on July 1, 2014, and as of that date, AERC is a wholly-owned subsidiary of Avista Corp. See "Note 4 of the Notes to Consolidated Financial Statements" for further discussion regarding this acquisition.

We have other businesses, including sheet metal fabrication, venture fund investments and real estate investments, as well as certain other investments of Avista Capital, Inc. (Avista Capital), which is a direct, wholly owned subsidiary of Avista Corp. In addition, as of July 1, 2014 we own AERC and AJT Mining Properties, Inc. (AJT Mining), which is a wholly-owned subsidiary of AERC and is an inactive mining company holding certain properties. 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.

Total Avista Corp. shareholders' equity was $1,483.7 million as of December 31, 2014, of which $57.3 million represented our investment in Avista Capital and $91.0 million represented our investment in AERC.

During the first half of 2014, Avista Capital's subsidiaries included Ecova, Inc. (Ecova), which was an 80.2 percent owned subsidiary prior to its disposition on June 30, 2014. Ecova was 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 "Item 6. Selected Financial Data" and "Note 23 of the Notes to Consolidated Financial Statements" for information with respect to the operating performance of each business segment (and other subsidiaries). See "Note 5 of the Notes to Consolidated Financial Statements" for information regarding the disposition of Ecova.

AVISTA UTILITIES

General

Through our Avista Utilities operating division, we generate, transmit and distribute electricity and distribute natural gas in the Pacific Northwest. 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.

Avista Utilities 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 2014, we supplied retail electric service to 370,000 customers and retail natural gas service to 330,000 customers across Avista Utilities' service territory. Avista Utilities' service territory covers 30,000 square miles with a population of 1.5 million. Certain of our generating facilities are located in Montana, and we supply electricity to a small number of customers in Montana, most of whom are employees who operate one of such facilities. 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, Avista Utilities generates electricity from facilities that we own and we purchase capacity, 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 Avista Utilities' 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.

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

Avista Utilities' 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 $15.8 million in 2014, $26.5 million in 2013 and $12.7 million in 2012. Transmission revenues for 2013 include $11.7 million from the Bonneville Power Administration (BPA) for past use of our electric transmission system.

Electric Requirements

Avista Utilities' peak electric native load requirement for 2014 occurred on February 6, 2014 at which time our total obligation was 2,223 MW consisting of:

- native load of 1,715 MW,
- long-term wholesale obligations of 221 MW, and
- short-term wholesale obligations of 287 MW.

At that time our maximum resource capacity available was 2,594 MW, which included:

- company-owned or controlled electric generation of 1,667 MW,
- long-term hydroelectric contracts with certain Public Utility Districts (PUDs) of 154 MW,
- long-term thermal generation contract with Lancaster Plant of 280 MW,
- other long-term wholesale contracts of 191 MW, and
- short-term wholesale purchases of 302 MW.

Electric Resources

Avista Utilities has 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 2014, 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 Avista Utilities owns and operates 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 2015 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 530 average megawatts (aMW) (or 4.6 million MWhs). Hydroelectric resources provided 573 aMW for 2014, 527 aMW for 2013 and 583 aMW for 2012.

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

	2014	2013	2012
Noxon Rapids	1,968	1,581	1,823
Cabinet Gorge	1,194	1,042	1,199
Post Falls	84	85	83
Upper Falls	67	68	60
Monroe Street	103	105	102
Nine Mile	56	83	106
Long Lake	476	505	513
Little Falls	195	177	202
Total company-owned hydroelectric generation	4,143	3,646	4,088
Long-term hydroelectric contracts with PUDs	877	970	1,022
Total hydroelectric generation	5,020	4,616	5,110
Normal hydroelectric generation (1)	4,663	4,678	4,761
Percentage of normal	108%	99%	107%

(1) Normal hydroelectric generation is determined by applying an upstream regulation calculation to median natural water flow information. Natural water flow is the flow of the rivers without the influence of dams, whereas regulated water flow

takes into account any water flow changes from upstream dams due to releasing or holding back water. The calculation of normal varies annually due to the timing of upstream dam regulation throughout the year.

Thermal Resources Avista Utilities owns the following thermal resources:

- the combined cycle 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:

	2014	2013	2012
Coyote Springs 2	1,495	1,796	1,142
Colstrip	1,464	1,227	1,499
Kettle Falls GS	259	294	209
Northeast CT, Rathdrum CT, Boulder Park and Kettle Falls CT	34	66	14
Total company-owned thermal generation	3,252	3,383	2,864
Long-term contract with Lancaster Plant	1,195	1,656	1,208
Total thermal generation	4,447	5,039	4,072

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 Palouse Wind is a wind generation project developed by Palouse Wind, LLC (Palouse Wind), and located in Whitman County, Washington. In June 2011, we entered into a 30-year PPA with Palouse Wind to acquire all of the power and renewable attributes produced by the project at a fixed price per MWh with a fixed escalation of the price over the term of the agreement. The project has a nameplate capacity of approximately 105 MW and is expected to produce approximately 40 aMW. Deliveries from the project began during the fourth quarter of 2012. Generation from Palouse Wind was 335,291 MWhs in 2014 and 297,027 MWhs in 2013. We have an annual option to purchase the wind project following the 10th anniversary of its December 2012 commercial operation date. The purchase price per the PPA is a fixed price per KW of in-service capacity with a fixed decline in the price per KW over the remaining 20 year term of the agreement.

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 UTC and the 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 2014, 2013 and 2012. 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

Avista Corp. is a licensee under the Federal Power Act (FPA) 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 FPA. 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.

Cabinet Gorge and Noxon Rapids are under one 45-year FERC license issued in March 2001. See “Cabinet Gorge Total Dissolved Gas Abatement Plan” in “Note 20 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 20 of the Notes to Consolidated Financial Statements.”

Future Resource Needs

Avista Utilities has 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 1,062 aMW in 2014, 1,086 aMW in 2013 and 1,075 aMW in 2012. The following is a forecast of our average annual energy requirements and resources for 2015 through 2018:

Forecasted Electric Energy Requirements and Resources
(aMW)

	2015	2016	2017	2018
Requirements:				
System load	1,068	1,074	1,084	1,091
Contracts for power sales (1)	124	91	51	39
Total requirements	1,192	1,165	1,135	1,130
Resources:				
Company-owned and contract hydro generation (2)	504	474	488	486
Company-owned and contract thermal generation (3)	723	700	723	692
Other contracts for power purchases	225	191	163	155
Total resources	1,452	1,365	1,374	1,333
Surplus resources	260	200	239	203
Additional available energy (4)	160	172	174	174
Total surplus resources	420	372	413	377

(1) The contracts for power sales decrease due to certain contracts expiring in each of these years. We are currently evaluating the future plan for the additional resources made available due to the expiration of these contracts.

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

(3) Includes our long-term contract with the owner of the Lancaster Plant. Excludes Boulder Park GS, Kettle Falls CT, 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. The decreases in availability during 2016 and 2018 at these facilities are related to scheduled maintenance at Colstrip.

(4) The combined maximum capacity of Boulder Park GS, Kettle Falls CT, Northeast CT and Rathdrum CT is 278 MW, with estimated available energy production as indicated for each year.

In August 2013, we filed our 2013 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 2013 IRP include:

- In our IRP in 2011, we had certain recommendations for new renewable resources. These have been met with a 30-year PPA with Palouse Wind and the Kettle Falls GS being qualified as a renewable energy resource under the Washington state Energy Independence Act.
- Load growth is expected to be approximately 1 percent, a decline from the growth of 1.6 percent forecasted in 2011. This delays the need for a new natural gas-fired resource by one year. The decrease in expected load growth is primarily due to energy efficiency programs (using less energy to perform activities) over the next 20 years. See "Item 7. Management Discussion and Analysis – Forecasted Customer and Load Growth and Economic Conditions and Utility Load Growth" for further discussion regarding utility customer growth, load growth, and the general economic conditions in our service territory.
- Demand response (temporarily reducing the demand for energy) is included in the Preferred Resource Strategy for the first time and could provide 19 MW of peak energy reduction in the 2022 to 2027 time frame.
- 575 MW of additional natural gas-fired generation facilities are required between 2020 and 2033.
- 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 2015. Our resource strategy may change from the 2013 IRP based on market, legislative and regulatory developments.

We are subject to the Washington state Energy Independence Act, which requires us to obtain a portion of our electricity from qualifying renewable resources or through purchase of renewable energy credits and acquiring all cost effective conservation measures. Future generation resource decisions will be impacted by legislation for restrictions on GHG 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 Avista Utilities provides 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. Our natural gas procurement strategy is to provide reliable supply to our customers with some level of price certainty. We procure natural gas from various supply basins and over varying time periods. The resulting portfolio is a diversified mix of spot market purchases and forward fixed price purchases, utilizing physical and financial derivative instruments. We also use natural gas storage to support high demand periods and to procure natural gas when prices may be lower. Securing prices throughout the year and even into subsequent years provides a level of price certainty and can mitigate price volatility to customers between years.

Weather is a key component of our natural gas customer load. This load is highly variable and daily natural gas loads can differ significantly from the monthly forecasted 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 portion of our customer's 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 portion of our natural gas supply requirements unhedged for purchase in the short-term spot markets.

Our purchase of natural gas supply is governed by our procurement plan. This plan is reviewed and modified annually by an internal management group. The updated plan is presented and discussed with staff in all three state jurisdictions. Communication with staff does not constitute pre-approval; however, it provides transparency to our procurement practices and offers the staff and other stakeholders an opportunity to express concerns, ask questions and learn about the factors contributing to the plan's development and subsequent execution. The plan is then presented to our Risk Management Committee (RMC) for approval. Once approval is received, the plan is implemented and monitored by our gas supply and risk management groups.

The plan's ongoing progress is also presented to UTC and IPUC staff in semi-annual meetings, and updates are given to the OPUC staff quarterly. Other stakeholders (Public Counsel, Citizen Utility Board) are invited to participate. The RMC is provided with an update on plan results and changes in their monthly meetings. These activities provide transparency for the natural gas supply procurement plan. Any material changes to the plan are documented and communicated to RMC members.

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

- wholesale market sales of surplus natural gas supplies,
- purchases and sales of natural gas to optimize use of pipeline and storage capacity, and
- participation in the transportation capacity release market.

We also provide distribution transportation service to qualified, large commercial and industrial natural gas customers who purchase natural gas through third-party marketers. For these customers, we receive their purchased natural gas from such third-party marketers into our distribution system and redeliver it to the customers' premise.

Optimization transactions that we engage in throughout the year are included in our annual purchased gas cost adjustment filings with the various commissions and they are subject to review for prudency during this process.

Natural Gas Supply Avista Utilities purchases all of its natural gas in wholesale markets. We are connected to multiple supply basins in the western United States and Canada through firm capacity transportation rights on six different 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 transportation rights provide the capacity to serve approximately 25 percent of peak natural gas customer demands from domestic sources, and 75 percent from Canadian sourced supply. 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 resource mix to vary.

Natural Gas Storage Avista Utilities owns a one-third interest in Jackson Prairie, an underground natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 12.0 million therms, with a total working natural gas capacity of 256 million therms. As an owner, our share is one-third of the peak day deliverability and total working capacity. We also contract for additional storage capacity and delivery at Jackson Prairie from Northwest Pipeline for a portion of their one-third share of the storage project.

Natural gas storage enables us to store gas in the summer when prices are traditionally lower and withdraw during higher priced winter months. It is also used as a variable peaking resource during cold weather events.

Natural Gas Pipeline Replacement In 2011 Avista Utilities began implementation of a plan to replace certain vintages of Aldyl A natural gas pipe within our distribution systems in Washington, Idaho, and Oregon. In early 2012, we released our protocol report to each state utility commission describing our Aldyl A natural gas pipe replacement plan, proposing to replace our Aldyl A natural gas pipe across our three state jurisdictions over a 20-year period. 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 pipe replacement plans. We filed our pipe replacement plan, which included our Aldyl A protocol report, with the UTC in 2013. Current annual replacement costs are approximately $16 million per year, which we expect to sustain, subject to inflation, over the 20-year period. We expect to receive cost recovery for these capital expenditures from the three jurisdictions over the life of these assets.

Regulatory Issues

General As a public utility, Avista Corp. is 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 OPUC, and the MPSC. Approval of the issuance of securities is not required from the MPSC. We are also subject to the jurisdiction of the FERC for licensing of hydroelectric generation resources, and for electric transmission services and wholesale sales.

Since Avista Corp. is a "holding company," we are also subject to the jurisdiction of the FERC under the Public Utility Holding Company Act of 2005, which imposes certain reporting and other requirements. We, and all of our subsidiaries (whether or not engaged in any energy related business) are required to maintain books, accounts and other records in accordance with the FERC regulations and to make them available to the FERC and the state utility commissions. In addition, upon the request of any state utility commission, or of Avista Corp., the FERC would have the authority to review assignment of costs of non-power goods and administrative services among us and our subsidiaries. The FERC has the authority generally to require that rates subject to its jurisdiction be just and reasonable and in this context would continue to be able to, among other things, review transactions of any affiliated company.

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 generally 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 retail rates in Washington and Idaho is made on the basis of net investment, operating expenses and revenues for a test year that ended prior to the date of the request, plus certain adjustments designed to reflect the expected revenues, expenses and net investment during the period new retail rates will be in effect. The retail rates approved by the state commissions in a rate proceeding may not provide sufficient revenues to provide recovery of costs and a reasonable return on investment for a number of reasons, including but not limited to, unexpected changes in revenues, expenses and investment following the time new retail rates are requested in the rate proceeding, and exclusion of certain costs and investment by the commission from the rate making process. Oregon currently allows the use of a forecasted test year to establish retail rates for the rate year.

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 22 of the Notes to Consolidated Financial Statements" for additional information about regulation, depreciation and deferred income taxes.

General Rate Cases Avista Utilities regularly reviews 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 Avista Utilities defers 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 22 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, Avista Utilities defers the recognition in the income statement of the natural gas costs that vary from the level currently recovered from our retail customers as authorized by each of our jurisdictions. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Avista Utilities – Regulatory Matters – Purchased Gas Adjustments" and "Note 22 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 FPA 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 Order No. 888 and continuing with subsequent rulemakings and policies, 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) or an independent system operator (ISO).

Avista Utilities meets its FERC requirements to coordinate transmission planning activities with other regional entities through ColumbiaGrid. ColumbiaGrid is a Washington nonprofit membership corporation with an independent board formed to improve the operational efficiency, reliability, and planned expansion of the transmission grid in the Pacific Northwest. We became a member of ColumbiaGrid in 2006 during its formation. ColumbiaGrid is not an ISO, but performs only those functions that its members request, as set forth in specific agreements. Currently, ColumbiaGrid fills the role of facilitating our regional transmission planning as required in Order No. 1000 and other clarifying Orders. ColumbiaGrid and its members also work with other western organizations to address transmission planning, including WestConnect and the Northern Tier Transmission Group (NTTG). In 2011, we became a registered Planning Participant of the NTTG. 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.

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 penalties for non-compliance with these standards and other FERC regulations.

The FERC certified the 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 the 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. Requirements relating to cyber security are continually evolving. Our compliance with version 5 of the NERC's Critical Infrastructure Protection standard is driving several physical and electronic security initiatives in our control centers, generating stations and substations. We do not expect the costs of the physical and electronic securities initiatives to have a material impact to our financial results.

AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

	Years Ended December 31,		
	2014	2013	2012
ELECTRIC OPERATIONS			
OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 338,697	$ 331,867	$ 315,137
Commercial	300,109	289,604	286,568
Industrial	110,775	113,632	119,589
Public street and highway lighting	7,549	7,267	7,240
Total retail	757,130	742,370	728,534
Wholesale	138,162	127,556	102,736
Sales of fuel	83,732	126,657	115,835
Other	27,467	36,071	21,067
Provision for earnings sharing (1)	(7,503)	(2,048)	—
Total electric operating revenues	$ 998,988	$ 1,030,606	$ 968,172
ENERGY SALES (Thousands of MWhs):			
Residential	3,694	3,745	3,608
Commercial	3,189	3,147	3,127
Industrial	1,868	1,979	2,100
Public street and highway lighting	25	26	26
Total retail	8,776	8,897	8,861
Wholesale	3,686	3,874	3,733
Total electric energy sales	12,462	12,771	12,594
ENERGY RESOURCES (Thousands of MWhs):			
Hydro generation (from Company facilities)	4,143	3,646	4,088
Thermal generation (from Company facilities)	3,252	3,383	2,864
Purchased power - hydro generation from long-term contracts with PUDs	877	970	1,022
Purchased power - thermal generation from long-term contract with Lancaster plant	1,195	1,656	1,208
Purchased power - wind generation from long-term contract with Palouse Wind	335	297	61
Purchased power - wholesale	3,208	3,452	3,995
Power exchanges	(25)	(20)	(10)
Total power resources	12,985	13,384	13,228
Energy losses and Company use	(523)	(613)	(634)
Total energy resources (net of losses)	12,462	12,771	12,594
NUMBER OF RETAIL CUSTOMERS (Average for Period):			
Residential	324,188	321,098	318,692
Commercial	40,988	40,202	39,869
Industrial	1,385	1,386	1,395
Public street and highway lighting	531	527	503
Total electric retail customers	367,092	363,213	360,459
RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (KWh)	11,394	11,664	11,323
Revenue per KWh (in cents)	9.17	8.86	8.73
Annual revenue per customer	$ 1,044.76	$ 1,033.54	$ 988.84
AVERAGE HOURLY LOAD (aMW)	1,062	1,086	1,075

AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

	Years Ended December 31,		
	2014	2013	2012
REQUIREMENTS AND RESOURCE AVAILABILITY at time of system peak (MW):			
Total requirements (winter):			
Retail native load	1,715	1,669	1,554
Wholesale obligations	508	554	637
Total requirements (winter)	2,223	2,223	2,191
Total resource availability (winter)	2,594	2,767	2,618
Total requirements (summer):			
Retail native load	1,606	1,577	1,579
Wholesale obligations	691	569	906
Total requirements (summer)	2,297	2,146	2,485
Total resource availability (summer)	2,608	2,813	3,060
COOLING DEGREE DAYS: (2)			
Spokane, WA			
Actual	631	709	535
30-year average (4)	394	394	434
% of average	160%	180%	123%
HEATING DEGREE DAYS: (3)			
Spokane, WA			
Actual	6,215	6,683	6,256
30-year average (4)	6,820	6,780	6,676
% of average	91%	99%	94%

(1) This provision for earnings sharing is specifically related to the Idaho general rate case which was settled in March 2013. See "Item 7. Management's Discussion and Analysis - Idaho General Rate Cases" for further discussion of this provision.

(2) 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).

(3) 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).

(4) The 30-year average heating and cooling degree days fluctuated in 2013 due to a change in our methodology for calculating the amount. In 2013, we have switched to a rolling 30-year average whereas in prior years we only received updated 30-year average data on a periodic basis.

AVISTA UTILITIES NATURAL GAS OPERATING STATISTICS

	Years Ended December 31,		
	2014	2013	2012
NATURAL GAS OPERATIONS			
OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 203,373	$ 206,330	$ 196,719
Commercial	103,179	102,225	98,994
Interruptible	2,792	2,681	2,232
Industrial	4,158	3,599	3,635
Total retail	313,502	314,835	301,580
Wholesale	228,187	194,717	158,631
Transportation	7,735	7,576	7,032
Other	7,461	8,573	6,930
Provision for earnings sharing (1)	(221)	(442)	—
Total natural gas operating revenues	$ 556,664	$ 525,259	$ 474,173
THERMS DELIVERED (Thousands of Therms):			
Residential	190,171	204,711	189,152
Commercial	116,748	122,245	115,083
Interruptible	5,033	5,694	4,363
Industrial	5,648	5,181	5,073
Total retail	317,600	337,831	313,671
Wholesale	545,620	524,818	586,193
Transportation	162,311	159,976	154,704
Interdepartmental and Company use	411	418	381
Total therms delivered	1,025,942	1,023,043	1,054,949
SOURCES OF NATURAL GAS DELIVERED (Thousands of Therms):			
Purchases	902,040	834,068	919,684
Storage - injections	(99,550)	(97,338)	(105,904)
Storage - withdrawals	68,722	129,006	93,850
Natural gas for transportation	162,311	159,976	154,704
Distribution system losses	(7,581)	(2,669)	(7,385)
Total natural gas delivered	1,025,942	1,023,043	1,054,949
NUMBER OF RETAIL CUSTOMERS (Average for Period):			
Residential	291,928	288,708	286,522
Commercial	34,047	33,932	33,763
Interruptible	37	38	38
Industrial	264	259	263
Total natural gas retail customers	326,276	322,937	320,586
RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (therms)	651	709	660
Revenue per therm (in dollars)	$ 1.07	$ 1.01	$ 1.04
Annual revenue per customer	$ 696.66	$ 714.67	$ 686.57

AVISTA UTILITIES NATURAL GAS OPERATING STATISTICS

	Years Ended December 31,		
	2014	2013	2012
HEATING DEGREE DAYS: (2)			
Spokane, WA			
Actual	6,215	6,683	6,256
30-year average (3)	6,820	6,780	6,676
% of average	91%	99%	94%
Medford, OR			
Actual	3,382	4,576	4,182
30-year average (3)	4,539	4,539	4,422
% of average	75%	101%	95%

(1) This provision for earnings sharing is specifically related to the Idaho general rate case which was settled in March 2013. See "Item 7. Management's Discussion and Analysis - Idaho General Rate Cases" for further discussion of this provision.
(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).
(3) The 30-year average heating degree days fluctuated in 2013 due to a change in our methodology for calculating the amount. In 2013, we have switched to a rolling 30-year average whereas in prior years we only received updated 30-year average data on a periodic basis.

ALASKA ELECTRIC LIGHT AND POWER COMPANY

AEL&P is the primary operating subsidiary of AERC. AEL&P is the sole utility providing electrical energy in the City and Borough of Juneau, Alaska. Juneau is a geographically isolated community with no electric interconnections with the transmission facilities of other utilities and no pipeline access to natural gas or other fuels. Juneau's economy is primarily driven by government activities, tourism, commercial fishing, and mining, as well as activities as the commercial hub of southeast Alaska.

AEL&P owns and operates electric generation, transmission and distribution facilities located in Juneau. AEL&P operates five hydroelectric generation facilities with 102.7 MW of hydroelectric generation capacity as of December 31, 2014. AEL&P owns four of these generation facilities (totaling 24.7 MW of capacity) and has a power purchase commitment for the output of the Snettisham hydroelectric project (totaling 78 MW of capacity). The Snettisham power purchase agreement is accounted for as a capital lease.

The Snettisham hydroelectric project is AEL&P's primary generation facility and the main power source for Juneau, supplying approximately two-thirds of the area's electricity. The Snettisham hydroelectric project was constructed and operated by the federal government and subsequently purchased by the Alaska Industrial Development and Export Authority (AIDEA). AEL&P has a long-term power purchase agreement and operating and maintenance agreement with the AIDEA to operate and maintain the facility. This power purchase agreement is a take-or-pay obligation expiring in December 2038, to purchase all the output of the 78 MW Snettisham hydroelectric project. AIDEA issued $100.0 million in revenue bonds (of which $70.0 million was outstanding as of December 31, 2014), to finance its acquisition of the project and the payments by AEL&P are designed to be more than sufficient to enable the AIDEA to pay the principal of and interest on its revenue bonds, maturing in January 2034. The payments by AEL&P under the agreement are unconditional, notwithstanding any suspension, reduction or curtailment of the operation of the project. For accounting purposes, this power purchase agreement is treated as a capital lease and as of December 31, 2014, the capital lease obligation was $70.0 million. Snettisham Electric Company, a non-operating subsidiary of AERC, has the option to purchase the Snettisham project at any time for the principal amount of the bonds outstanding at that time. See "Note 14 of the Notes to Consolidated Financial Statements" for further discussion of the Snettisham capital lease obligation.

As of December 31, 2014, AEL&P also had 93.9 MW of diesel generating capacity from three facilities to provide back-up service to firm customers when necessary.

The following table shows AEL&P's hydroelectric generation (in thousands of MWhs) during the time periods indicated below:

	Second half of 2014	Full 12 months of 2014
Snettisham	119	276
Lake Dorothy	54	85
Salmon Creek	16	25
Annex Creek	14	28
Gold Creek	4	6
Total hydroelectric generation	207	420
Normal hydroelectric generation	211	430
Percentage of normal	98%	98%

Only the hydroelectric generation for the second half of 2014 in the table above was included in Avista Corp.'s overall results for 2014. The full 12 months of 2014 in the table above is presented for information purposes only.

As of December 31, 2014, AEL&P served 16,394 customers. AEL&P’s customer classes include residential, small commercial, large commercial, governmental and street lighting customer classes. Its primary customers include city, state and federal governmental entities located in Juneau, as well as a mine located in the Juneau area. Most of AEL&P’s customers are served on a firm basis while certain of its customers, including its largest customer, are served on an interruptible sales basis. AEL&P maintains separate rate tariffs for each of its customer classes, as well as separate seasonal rates.

As of December 31, 2014, AEL&P had 59 full-time employees and employs approximately 15-18 temporary, seasonal employees each year. Approximately half of AEL&P’s full-time employees are members of the International Brotherhood of Electrical Workers (IBEW) and subject to a collective bargaining agreement.

AEL&P’s operations are subject to regulation by the RCA with respect to rates, standard of service, facilities, accounting and certain other matters, but not with respect to the issuance of securities. Rate adjustments for AEL&P’s customers require approval by the RCA pursuant to RCA regulations. AEL&P's last general rate case was filed in 2010 and approved by the RCA in 2011. The RCA approved a capital structure including 53.8 percent equity and an authorized return on equity of 12.875 percent. We expect that AEL&P will maintain a similar capital structure going forward.

AEL&P is also subject to the jurisdiction of the FERC concerning the permits and licenses necessary to operate certain of its hydroelectric facilities. One of these licenses (for the Salmon Creek and Annex Creek hydroelectric projects) expires in 2018. Since AEL&P has no electric interconnection with other utilities and makes no wholesale sales, it is not subject to general FERC jurisdiction.

The Snettisham hydroelectric project is subject to regulation by the State of Alaska with respect to dam safety and certain aspects of its operations. In addition, AEL&P is subject to regulation with respect to air and water quality, land use and other environmental matters under both federal and state laws.

OTHER BUSINESSES

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

	2014	2013
Spokane Energy	$ 30,404	$ 42,829
Avista Energy	—	12,399
METALfx	12,065	11,105
Steam Plant and Courtyard Office Center	7,278	7,055
Alaska companies (AERC and AJT Mining)	7,507	—
Avista Capital - standalone	13,221	420
Other	9,735	7,474
Total	$ 80,210	$ 81,282

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 \$28.2 million and \$40.6 million for 2014 and 2013, respectively, and the likelihood of this asset being at risk of impairment is remote. In addition to the assets above, Spokane Energy has nonrecourse long-term debt outstanding in the amount of \$1.4 million and \$17.8 million at December 31, 2014 and 2013, respectively, related to the acquisition of the fixed rate electric capacity contract. The final payment was made in January 2015.

Avista Energy is a former electricity and natural gas marketing, trading and resource management business, which is 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 legal proceedings in the Pacific Northwest Refund Proceeding. During 2014, Avista Energy finalized a settlement agreement in its other legal proceedings including the FERC Inquiry, the California Refund Proceeding and the California Attorney General Complaint (the “Lockyer Complaint”). See "Note 20 of the Notes to the Consolidated Financial Statements" for further detail regarding these legal proceedings. The assets associated with Avista Energy as of December 31, 2013 were deferred tax assets related to its former operations.

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 mixed use commercial and retail office space).

As of July 1, 2014 we own AERC and AJT Mining, which is a wholly-owned subsidiary of AERC and is an inactive mining company holding certain properties.

The assets at Avista Capital - standalone as of December 31, 2014 primarily consist of the escrow receivables related to the sale of Ecova on June 30, 2014. See "Note 5 of the Notes to Consolidated Financial Statements" for further detail regarding this transaction.

Our other investments and operations include emerging technology venture capital funds.

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 our core utility business and related businesses and are planning to incur \$2.0 million to \$3.0 million per year exploring opportunities to develop new markets and ways for customers to improve the use of 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.

In particular, Salix LNG is exploring markets that could be served with liquefied natural gas, primarily in western North America. These markets include power generation, marine bunkering and transportation fuels.

Also, our acquisition of AERC provides us a platform to explore strategic opportunities to bring natural gas to Southeast Alaska.

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:

- certain retail electricity and natural gas sales,

- the cost of natural gas supply,
- the cost of power supply, and
- damage 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 the Pacific Northwest. 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 are generally 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. Inter-regional natural gas pipelines and competition for supply can allow demand-driven price volatility in other regions of North America to affect prices in our region, even though there may be less extreme weather conditions in our area.

The cost of power supply can be significantly affected 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 based on wind patterns as wind generation capacity is material in our region but its contribution to supply is inconsistent.

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.

The price of power tends to be lower during periods with excess supply, such as the spring when hydroelectric conditions are usually at their maximum and various facilities are required to operate to meet environmental mandates. Oversupply can be exacerbated when intermittent resources such as wind generation are producing output that may be supported by price subsidies. In extreme situations, we may be required to sell excess energy at negative prices.

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.

Damage to facilities may be caused by severe weather, such as snow, ice, wind storms or avalanches. The cost to implement rapid or any repair to such facilities can be significant. Overhead electric lines are most susceptible to damage caused by severe weather.

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 with the exception of 2013 which saw a slight decrease from 2012 actual costs. 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.

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

Energy commodity prices can be 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 the 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 are 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 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 cannot and do not attempt to fully hedge our energy resource assets or our forecasted net positions for various time horizons. 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 April 2019. Our subsidiary AEL&P has a committed line of credit in the amount of $25.0 million with an expiration date of November 2019. There is no assurance that we will have access to credit beyond these expiration dates. The committed line of credit agreements contain customary covenants and default provisions. In the event of default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock.

We hedge a portion of our interest rate risk with financial derivative instruments, which may include interest rate swaps and U.S. Treasury lock agreements. We increased the use of interest rate swaps in 2013 and 2014. If market interest rates decrease below the interest rates we have locked in, this will result in a liability related to our interest rate swap agreements, which can be significant. As of December 31, 2014, we had a net interest rate derivative liability of $76.6 million, which increased significantly in 2014 due to declining long-term interest rates. We did not have any U.S. Treasury lock agreements outstanding as of December 31, 2014. We may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the derivative instruments. Settlement of interest rate derivative instruments in a liability position could require a significant amount of cash, which could negatively impact our liquidity and short-term credit availability and increase interest expense over the term of the associated debt.

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.

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

- blackouts or disruptions to distribution, transmission or transportation systems,
- unplanned 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 and general business operations.

Disasters may affect the general economy, financial and capital markets, specific industries, or our ability to conduct business. As protection against operational and event risks, we maintain business continuity and disaster recovery plans, 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.

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. Additionally, the facilities and systems of clients, suppliers and third party service providers could be vulnerable to these same risks and, to the extent of interconnection to our technology, may impact us. Any failure, unexpected, or unauthorized unavailability 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, competitiveness, and result in costly litigation and impact on our results of operations. 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.

Terrorist attacks could also be directed at physical electric and natural gas facilities, as well as technology systems.

There have been numerous recent changes in legislation, related administrative rulemakings, 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 the long-term global and our utilities' service area 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 could 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 20 of the Notes to Consolidated Financial Statements" for further details of these matters.

We may be adversely affected by our inability to successfully implement certain technology projects.

In February 2015 we implemented new customer information and work management systems. Our customer information and work management systems are two of our most critical technology systems and are interconnected to many other systems in our company. These implementations have resulted in certain changes to business processes and internal controls. There are inherent risks associated with replacing and changing these types of systems, such as delayed and / or inaccurate customer bills, potential disruption of our business, substantial unplanned costs and the potential lack of recovery through rates which could have a material adverse effect on our results of operations, financial condition and cash flows.

Our acquisition of AERC may not achieve its intended results.

On July 1, 2014, we completed the acquisition of AERC, and its subsidiary, AEL&P, the sole provider of electric services to 16,394 customers in Juneau, Alaska. Achieving the anticipated earnings contribution from AERC is subject to numerous uncertainties, including market conditions and risks related to AERC's business. This transaction could result in increased costs, decreases in the expected revenues from AERC, the impairment of goodwill or other assets, and diversion of management time and resources, which could have a material adverse effect on our results of operations, financial condition and cash flows.

A majority of AEL&P's hydroelectric power generation is provided by a single facility that is subject to a long-term power purchase agreement and operating and maintenance agreement in connection with which AEL&P is required to make certain payments.

While AEL&P operates several hydroelectric power generation facilities and has diesel generating capacity from multiple facilities to provide backup service to firm customers when necessary, a single hydroelectric power generation facility, the Snettisham hydroelectric project, provides approximately two-thirds of AEL&P's hydroelectric power generation. Any issues that negatively affect the Snettisham hydroelectric project's ability to generate or transmit power, any decrease in the demand for the power generated by the Snettisham hydroelectric project or any loss by AERC or its subsidiaries of their contractual rights with respect thereto or other adverse effect thereon could negatively affect our results of operations, financial condition and cash flows.

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 Avista Utilities' properties are subject to the lien of Avista Corp.'s 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) (3)	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) (4)	4	265.0	273.0
Post Falls (Spokane)	6	14.8	15.4
Montana:			
Noxon Rapids (Clark Fork)	5	487.8	562.4
Total Hydroelectric		920.8	1,022.0
Thermal Generating Stations (cycle, fuel source)			
Washington:			
Kettle Falls GS (combined-cycle, wood waste) (5)	1	50.7	53.5
Kettle Falls CT (combined-cycle, natural gas) (5)	1	7.2	6.9
Northeast CT (simple-cycle, natural gas)	2	61.8	64.8
Boulder Park GS (simple-cycle, natural gas)	6	24.6	24.0
Idaho:			
Rathdrum CT (simple-cycle, natural gas)	2	166.5	166.5
Montana:			
Colstrip Units 3 and 4 (simple-cycle, coal) (6)	2	233.4	222.0
Oregon:			
Coyote Springs 2 (combined-cycle, natural gas)	1	287.0	284.4
Total Thermal		831.2	822.1
Total Generation Properties		1,752.0	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, 2014.

(3) There are four units at the Nine Mile plant; however, Units 1 and 2 are not operating due to a mechanical failure. A project is underway to replace these units and restore capability. The present capability disclosed above represents the capability of the two operating units, which have a nameplate rating of 18 MW combined.

(4) For Cabinet Gorge, we have water rights permitting generation up to 265 MW. However, if natural stream flows will allow for generation above our water rights we are able to generate above our water rights. If natural stream flows only allow for generation at or below 265 MW, we are limited to generation of 265 MW. The present capability disclosed above represents the capability based on maximum stream flow conditions when we are allowed to generate above our water rights.

(5) These generating stations can operate as separate single-cycle plants or combined-cycle with the natural gas plant providing exhaust heat to the wood boiler to increase efficiency.

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

Electric Distribution and Transmission Plant

Avista Utilities owns and operates approximately 19,000 miles of primary and secondary electric distribution lines providing service to retail customers. We have an electric transmission system of 676 miles of 230 kV line and 1,553 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 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

Avista Utilities has natural gas distribution mains of approximately 3,400 miles in Washington, 2,000 miles in Idaho and 2,300 miles in Oregon. We have natural gas transmission mains of approximately 75 miles in Washington and 50 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 Jackson Prairie, an underground natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 12.0 million therms, with a total working natural gas capacity of 256 million therms. As an owner, our share is one-third of the peak day deliverability and total working capacity. Natural gas storage enables us to store gas in the summer when prices are traditionally lower and withdraw during higher priced winter months. Natural gas storage is also used as a variable peaking resource during cold weather events.

ALASKA ELECTRIC LIGHT AND POWER COMPANY

Substantially all of AEL&P's utility properties are subject to the lien of the AEL&P mortgage indenture.

AEL&P's utility electric properties, located in Alaska include the following:

Generation Properties and Transmission and Distribution Lines

	No. of Units	Nameplate Rating (MW) (1)	Present Capability (MW) (2)
Hydroelectric Generating Stations			
Snettisham (3)	3	78.2	78.2
Lake Dorothy	1	14.3	14.3
Salmon Creek	1	8.4	5.0
Annex Creek	2	4.1	3.6
Gold Creek	3	1.6	1.6
Total Hydroelectric		106.6	102.7
Diesel Generating Stations			
Lemon Creek	11	61.4	57.5
Auke Bay	3	36.2	28.3
Gold Creek	5	8.2	8.1
Total Diesel		105.8	93.9
Total Generation Properties		212.4	196.6

(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, 2014.
(3) AEL&P does not own this generating facility but has a power purchase agreement under which it has the right to purchase, and the obligation to pay for (whether or not energy is received), all of the capacity and energy of this facility. See further information at "Part 1. Item 1. Business - AEL&P Overview."

In addition to the generation properties above, AEL&P owns approximately 61 miles of transmission lines, which is primarily comprised of 69 kV line, and approximately 184 miles of distribution lines.

ITEM 3. LEGAL PROCEEDINGS

See “Note 20 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

Avista Corp. Market Information and Dividend Policy

Avista Corp.'s common stock is currently listed on the New York Stock Exchange under the ticker symbol “AVA.” As of January 31, 2015, there were 9,238 registered shareholders of our common stock.

Avista Corp.'s 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.

Avista Corp.'s net income available for dividends is generally derived from our regulated utility operations (Avista Utilities and AEL&P).

The payment of dividends on common stock could be limited by:

- certain covenants applicable to preferred stock (when outstanding) contained in the Company’s Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements (see Item 7. Management's Discussion and Analysis - "Capital Resources" for compliance with these covenants),
- the hydroelectric licensing requirements of section 10(d) of the FPA (see “Note 1 of Notes to Consolidated Financial Statements”), and
- certain requirements under the OPUC approval of the AERC acquisition. After the initial year, the OPUC does not permit one-time or special dividends from AERC to Avista Corp. and does not permit Avista Utilities' total equity to total capitalization to be less than 40 percent, without approval from the OPUC. However, the OPUC approval does allow for regular distributions of AERC earnings to Avista Corp. as long as AERC remains sufficiently capitalized and insured.

On February 6, 2015, Avista Corp.’s Board of Directors declared a quarterly dividend of $0.33 per share on the Company’s common stock. This was an increase of $0.0125 per share, or 4 percent from the previous quarterly dividend of $0.3175 per share.

For additional information, see “Notes 1, 17, 18 and 19 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
2014				
Dividends paid per common share	$ 0.3175	$ 0.3175	$ 0.3175	$ 0.3175
Trading price range per common share:				
High	$ 30.83	$ 33.58	$ 33.60	$ 37.37
Low	$ 27.71	$ 30.02	$ 30.35	$ 30.55
2013				
Dividends paid per common share	$ 0.305	$ 0.305	$ 0.305	$ 0.305
Trading price range per common share:				
High	$ 27.48	$ 29.26	$ 29.21	$ 28.45
Low	$ 24.10	$ 25.68	$ 25.55	$ 25.88

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."

Issuer Purchases of Equity Securities

On June 13, 2014, our Board of Directors approved the repurchase of up to 4 million shares of the Company's outstanding common stock, assuming the closure of the Ecova transaction (2014 program). Repurchases of common stock under the 2014 program commenced on July 7, 2014 and the 2014 program expired on December 31, 2014. Repurchases were made in the open market or in privately negotiated transactions. Through December 31, 2014, we repurchased 2,529,615 shares at a total cost of $79.9 million and an average cost of $31.57 per share. All repurchased shares under the 2014 program reverted to the status of authorized but unissued shares.

The following table provides information about share repurchases that we made during the three months ended December 31, 2014 (in thousands, except per share amounts):

	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Program	(d) Maximum Number of Shares that May Yet Be Purchased Under the Program
October 1 to October 31, 2014	606	$ 31.20	606	1,470
November 1 to November 30, 2014	—	—	—	1,470
December 1 to December 31, 2014	—	—	—	1,470
Total	606	$ 31.20	606	1,470

On December 16, 2014, our Board of Directors approved the repurchase of up to 800,000 shares of the Company's outstanding common stock, commencing on January 2, 2015, and continuing through March 31, 2015 (first quarter 2015 program). The number of shares repurchased through the first quarter 2015 program will be in addition to the number of shares repurchased under the 2014 program, which expired on December 31, 2014. The parameters of the first quarter 2015 program are consistent with the parameters of the 2014 program. We have not repurchased any shares under the first quarter 2015 program through January 31, 2015. All repurchased shares, if any, will revert to the status of authorized but unissued shares.

ITEM 6. SELECTED FINANCIAL DATA

(in thousands, except per share data and ratios)	Years Ended December 31,				
	2014	2013	2012	2011	2010
Operating Revenues:					
Avista Utilities	$ 1,413,499	$ 1,403,995	$ 1,354,185	$ 1,443,322	$ 1,419,646
AEL&P	21,644	—	—	—	—
Other	39,219	39,549	38,953	40,410	61,067
Intersegment eliminations	(1,800)	(1,800)	(1,800)	(1,800)	(24,008)
Total	$ 1,472,562	$ 1,441,744	$ 1,391,338	$ 1,481,932	$ 1,456,705
Income (Loss) from Continuing Operations (pre-tax):					
Avista Utilities	$ 239,976	$ 232,572	$ 188,778	$ 202,373	$ 198,200
AEL&P	6,221	—	—	—	—
Other	6,391	(1,483)	(1,680)	4,714	5,669
Total	$ 252,588	$ 231,089	$ 187,098	$ 207,087	$ 203,869
Net income from continuing operations	$ 119,866	$ 104,333	$ 76,803	$ 90,658	$ 85,058
Net income from discontinued operations	72,411	7,961	1,997	12,881	9,890
Net income	$ 192,277	$ 112,294	$ 78,800	$ 103,539	$ 94,948
Net income attributable to noncontrolling interests	$ (236)	$ (1,217)	$ (590)	$ (3,315)	$ (2,523)
Net Income (Loss) attributable to Avista Corporation shareholders:					
Avista Utilities	$ 113,263	$ 108,598	$ 81,704	$ 90,902	$ 86,681
AEL&P	3,152	—	—	—	—
Ecova - Discontinued operations	72,390	7,129	1,825	9,671	7,433
Other	3,236	(4,650)	(5,319)	(349)	(1,689)
Net income attributable to Avista Corp. shareholders	$ 192,041	$ 111,077	$ 78,210	$ 100,224	$ 92,425
Average common shares outstanding, basic	61,632	59,960	59,028	57,872	55,595
Average common shares outstanding, diluted	61,887	59,997	59,201	58,092	55,824
Common shares outstanding at year-end	62,243	60,077	59,813	58,423	57,120
Earnings per common share attributable to Avista Corp. shareholders, basic:					
Earnings per common share from continuing operations	$ 1.94	$ 1.74	$ 1.30	$ 1.56	$ 1.53
Earnings per common share from discontinued operations	1.18	0.11	0.02	0.17	0.13
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 3.12	$ 1.85	$ 1.32	$ 1.73	$ 1.66
Earnings per common share attributable to Avista Corp. shareholders, diluted:					
Earnings per common share from continuing operations	$ 1.93	$ 1.74	$ 1.30	$ 1.56	$ 1.52
Earnings per common share from discontinued operations	1.17	0.11	0.02	0.16	0.13
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 3.10	$ 1.85	$ 1.32	$ 1.72	$ 1.65

(in thousands, except per share data and ratios)	Years Ended December 31,				
	2014	2013	2012	2011	2010
Dividends declared per common share	$ 1.27	$ 1.22	$ 1.16	$ 1.10	$ 1.00
Book value per common share	$ 23.84	$ 21.61	$ 21.06	$ 20.30	$ 19.71
Total Assets at Year-End:					
Avista Utilities	$ 4,367,926	$ 3,940,998	$ 3,894,821	$ 3,809,446	$ 3,589,235
AEL&P	264,195	—	—	—	—
Other	80,210	81,282	95,638	112,145	129,774
Total (1)	$ 4,712,331	$ 4,022,280	$ 3,990,459	$ 3,921,591	$ 3,719,009
Long-Term Debt and Capital Leases (including current portion)	$ 1,498,486	$ 1,272,783	$ 1,228,739	$ 1,177,300	$ 1,101,857
Nonrecourse Long-Term Debt of Spokane Energy (including current portion)	$ 1,431	$ 17,838	$ 32,803	$ 46,471	$ 58,934
Long-Term Debt to Affiliated Trusts	$ 51,547	$ 51,547	$ 51,547	$ 51,547	$ 51,547
Total Avista Corp. Shareholders’ Equity	$ 1,483,671	$ 1,298,266	$ 1,259,477	$ 1,185,701	$ 1,125,784
Ratio of Earnings to Fixed Charges (2)	3.39	3.02	2.48	2.81	2.68

(1) The total assets at year-end for the years 2013 to 2010 exclude the total assets associated with Ecova of $339.6 million, $322.7 million, $292.9 million and $221.1 million, respectively.

(2) See Exhibit 12 for computations.

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

Business Segments

As of December 31, 2014, we have two reportable business segments, Avista Utilities and AEL&P. We also have other businesses which do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp. See "Part I, Item 1. Business - Company Overview" for further discussion of our business segments.

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):

	2014	2013	2012
Avista Utilities	$ 113,263	$ 108,598	$ 81,704
Alaska Electric Light and Power Company	3,152	—	—
Ecova - Discontinued operations (1)	72,390	7,129	1,825
Other	3,236	(4,650)	(5,319)
Net income attributable to Avista Corporation shareholders	$ 192,041	$ 111,077	$ 78,210

(1) The results for the year ended December 31, 2014 include the net gain on sale of Ecova of $69.7 million.

Executive Level Summary

Overall Results

Net income attributable to Avista Corporation shareholders was $192.0 million for 2014, an increase from $111.1 million for 2013. The increase was primarily due to the disposition of Ecova, which resulted in the recognition of a $69.7 million net gain. In addition, we recognized a $15.0 million pre-tax gain during the second quarter related to the settlement of the California power markets litigation involving Avista Energy. The gain from the litigation settlement was partially offset by a pre-tax contribution of $6.4 million of the proceeds to the Avista Foundation, a charitable organization funded by Avista Corp.

Earnings at Avista Utilities increased due to the implementation of general rate increases in each of our jurisdictions, lower net power supply costs and a decrease in interest expense, partially offset by the provision for earnings sharing in Idaho. There were also expected increases in other operating expenses, depreciation and amortization and taxes other than income taxes. Utility results for 2013 also included the net benefit from the settlement with the BPA.

Avista Utilities

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

- 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,
- 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.

Forecasted Customer and Load Growth

Based on our forecast for 2015 through 2018 for Avista Utilities' service area, we expect annual electric customer growth to average 1.2 percent, within a forecast range of 0.8 percent to 1.6 percent. We expect annual natural gas customer growth to average 1.0 percent, within a forecast range of 0.5 percent to 1.5 percent. We anticipate retail electric load growth to average 0.8 percent, within a forecast range of 0.5 percent and 1.1 percent. We expect natural gas load growth to average 1.3 percent, within a forecast range of 0.8 percent and 1.8 percent. The forecast ranges reflect (1) the inherent uncertainty associated with the economic assumptions on which forecasts are based and (2) natural gas customer and load growth has been historically more volatile.

In AEL&P's service area, we expect annual residential customer growth to be in a narrow range around 0.4 percent for 2015 through 2018. We expect no significant growth in commercial and government customers over the same period. We anticipate that average annual total load growth will be in a narrow range around 0.9 percent, with residential load growth averaging about 0.6 percent; commercial about 1.2 percent; and government about 1.0 percent. 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."

See also "Competition" for a discussion of competitive factors that could affect our results of operations in the future.

General Rate Cases (GRC)

In our utility operations (both Avista Utilities and AEL&P), 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. See further discussion under "Regulatory Matters."

Capital Expenditures

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. Avista Utilities' cash-basis capital expenditures (per the Consolidated Statement of Cash Flows) were $323.9 million for 2014. Our accrual-basis capital expenditures were $352.3 million for 2014. We expect Avista Utilities' capital expenditures to be about $375 million for 2015 and $350 million in 2016. AEL&P's capital expenditures were $1.6 million for the six month period July 1, 2014 to December 31, 2014. We expect to spend approximately $15 million for each of 2015 and 2016 related to capital expenditures at AEL&P. These estimates of capital expenditures are subject to continuing review and adjustment (see further discussion under “Capital Expenditures”).

Alaska Energy and Resources Company Acquisition

On July 1, 2014, we completed our acquisition of AERC, located in Juneau, Alaska, of which AEL&P is a wholly-owned subsidiary. As of July 1, 2014 AERC is a wholly-owned subsidiary of Avista Corp.

In connection with the closing, we issued 4,501,441 new shares of common stock to the shareholders of AERC based on a contractual formula that resulted in a price of $32.46 per share, reflecting a purchase price of $170.0 million, plus acquired cash, less outstanding debt and other closing adjustments.

This transaction resulted in the recording of $52.7 million in goodwill during 2014.

Also, our acquisition of AERC provides us a platform to explore strategic opportunities to bring natural gas to Southeast Alaska.

For additional information regarding the AERC transaction, see “Note 4 of the Notes to Consolidated Financial Statements.”

Ecova Disposition

On May 29, 2014, Avista Capital, Inc., our non-regulated subsidiary, entered into a definitive agreement to sell its interest in Ecova to Cofely USA Inc., an indirect subsidiary of GDF SUEZ, a French multinational utility company. The sales transaction was completed on June 30, 2014, for a sales price of $335.0 million in cash, less the payment of debt and other customary closing adjustments. At the closing of the transaction on June 30, 2014, Ecova became a wholly-owned subsidiary of Cofely USA Inc.

The purchase price of $335.0 million, as adjusted, was divided among the security holders of Ecova, including minority shareholders and option holders, pro rata based on ownership. Approximately $16.8 million (5 percent of the purchase price) will be held in escrow for 15 months from the closing of the transaction to satisfy certain indemnification obligations under the merger agreement, and an additional $1.0 million is being held in escrow pending resolution of adjustments to working capital, which is expected to be completed in early 2015.

Avista Capital and Cofely USA Inc. agreed to make an election under Code Section 338(h)(10) with respect to the purchase and sale of Ecova to allocate the merger consideration among the assets of Ecova acquired in the merger.

When all remaining escrow amounts are released, the sales transaction is expected to provide cash proceeds to Avista Corp., net of debt, payment to option and minority holders, income taxes and transaction expenses, of $143.5 million and result in a net gain of $69.7 million. The Company expects to receive the full amount of its portion of the remaining escrow accounts; therefore, these amounts are included in the gain calculation.

On July 1, 2014, we utilized a portion of the proceeds from the Ecova sales transaction to pay off the outstanding balance owed on our committed line of credit and we initiated a common stock share repurchase program.

Stock Repurchase Programs

During 2014, Avista Corp. repurchased 2,529,615 shares of our outstanding common stock at a total cost of $79.9 million and an average cost of $31.57 per share through our 2014 stock repurchase program. We did not make any repurchases under this program subsequent to October 2014.

Avista Corp. initiated a second stock repurchase program commencing on January 2, 2015 which will continue through March 31, 2015 for the repurchase of up to 800,000 shares of our outstanding common stock. We have not repurchased any shares under this program through January 31, 2015. See "Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" for further discussion of these stock repurchase programs.

California Power Markets Litigation Settlement and Avista Foundation Charitable Contribution

On June 23, 2014, Avista Energy (an unregulated indirect subsidiary of Avista Corp.) received $15.0 million in settlement proceeds from the completion of a litigation settlement with various California parties. The litigation was related to the prices paid for power in the California spot markets during the years 2000 and 2001. This resulted in Avista Energy recognizing an increase in pre-tax earnings of approximately $15.0 million, which was recorded as a reduction to other operating expenses within the non-utility operating expenses section of the Consolidated Statements of Income. See "Note 20 of the Notes to the Consolidated Financial Statements" for further information regarding this litigation settlement.

Subsequent to the receipt of the settlement proceeds, we contributed approximately $6.4 million of the proceeds to the Avista Foundation. The remainder of the proceeds were used to fund current operations and decrease reliance on short-term debt.

Liquidity and Capital Resources

During 2014, Avista Corp. received net cash proceeds of $205.4 million from the Ecova sale (prior to tax payments of $74.8 million made in 2014) and we expect to receive additional proceeds of $13.1 million from the escrow accounts related to the sale. We used the funds to pay off $151.5 million owed on our committed line of credit, we paid $79.9 million in a share repurchase program in the second half of 2014 and we initiated a second share repurchase program for the first quarter of 2015.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. In April 2014, we amended this committed line of credit agreement to extend the expiration to April 2019. The amendment also provides us with the option to request an extension for an additional one or two years beyond April 2019, provided, 1) there are no default events prior to the requested extension and 2) the remaining term of agreement, including the requested extension period, does not exceed five years. The amendment did not change the amount of the committed line of credit. As of December 31, 2014, there were $105.0 million of cash borrowings and $32.6 million in letters of credit outstanding leaving $262.4 million of available liquidity under this line of credit.

The Avista Corp. 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, 2014, we were in compliance with this covenant with a ratio of 52.8 percent.

In December 2014, we issued $60.0 million of first mortgage bonds to three institutional investors in a private placement transaction. The first mortgage bonds bear an interest rate of 4.11 percent and mature in 2044.

In 2014, we issued $154.2 million (net of issuance costs) of common stock, which includes $150.1 million associated with the acquisition of AERC and the remainder under the dividend reinvestment and direct stock purchase plan, and employee plans.

With respect to the acquisition of AERC on July 1, 2014 and the subsequent rebalancing of the capital structure at AERC and its primary subsidiary AEL&P, the following transactions occurred:

- Avista Corp. issued 4,501,441 shares of common stock for a total fair value of $150.1 million to acquire AERC.
- In September 2014, AEL&P issued $75.0 million of 4.54 percent first mortgage bonds due in 2044 to two institutional investors in a private placement transaction. The proceeds from the AEL&P bonds were used to repay approximately $38.0 million of existing AEL&P debt, with the remainder of the proceeds and cash on-hand being paid as a cash dividend of $50.0 million to Avista Corp.
- In December 2014, AERC entered into a 3.85 percent $15.0 million term loan agreement which matures in December 2019. The proceeds from this term loan were paid as a cash dividend to Avista Corp.

In November 2014, AEL&P entered into a committed line of credit in the amount of $25.0 million which expires in November 2019. AEL&P terminated its previous $14.5 million committed line of credit. As of December 31, 2014, there were no borrowings or letters of credit outstanding under this committed line of credit. AEL&P did not borrow under its current or previous committed lines of credit during the second half of 2014.

The AEL&P committed line of credit agreement contains customary covenants and default provisions including a covenant which does not permit the ratio of "consolidated total debt at AEL&P" to "consolidated total capitalization at AEL&P," (including the impact of the Snettisham obligation) to be greater than 67.5 percent at any time. As of December 31, 2014, AEL&P was in compliance with this covenant with a ratio of 59.6 percent.

For 2015, we expect to issue approximately $125.0 million of long-term debt in order to maintain an appropriate capital structure and to fund planned capital expenditures.

Through January 31, 2015, we repurchased less common stock through our stock repurchase programs than anticipated. If current market conditions continue through the end of the first quarter, we do not anticipate purchasing any of the 800,000 shares authorized under the first quarter 2015 program. If this occurs, we do not expect to issue any common stock during 2015 other than shares under the employee plans, which we estimate to be approximately $1.2 million.

After considering the expected issuances of long-term debt and common stock during 2015, 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.

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:

- seek recovery of operating costs and capital investments, and
- seek the opportunity to earn reasonable 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.

Washington General Rate Cases

2012 General Rate Cases

In December 2012, the UTC approved a settlement agreement in Avista Utilities' electric and natural gas general rate cases filed in April 2012. The settlement, effective January 1, 2013 provided that base rates for our Washington electric customers increase by an overall 3.0 percent (designed to increase annual revenues by $13.6 million), and base rates for our Washington natural gas customers increased by an overall 3.6 percent (designed to increase annual revenues by $5.3 million). Under the settlement, there was a one-year credit designed to return $4.4 million to electric customers from the ERM deferral balance so the net average electric rate increase to our customers in 2013 was 2.0 percent. The credit to customers from the ERM balance did not impact our earnings.

The approved settlement also provided that, effective January 1, 2014, base rates increased for our Washington electric customers by an overall 3.0 percent (designed to increase annual revenues by $14.0 million), and for our Washington natural gas customers by an overall 0.9 percent (designed to increase annual revenues by $1.4 million). The settlement provided for a one-year credit designed to return $9.0 million to electric customers from the ERM deferral balance, so the net average electric rate increase to our customers effective January 1, 2014 was 2.0 percent. The credit to customers from the ERM balance did not impact our earnings. The ERM balance as of December 31, 2014 was a liability of $14.2 million.

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

The December 2012 UTC Order approving the settlement agreement included certain conditions.

(1) The new retail rates that became effective on January 1, 2014 were temporary rates, and on January 1, 2015, electric and natural gas base rates were scheduled to revert back to 2013 levels absent any intervening action from the UTC. The original settlement agreement had a provision that we would not file a general rate case in Washington seeking new rates to take effect before January 1, 2015. In November 2014, the UTC approved a settlement agreement to our Washington general rate cases which were originally filed in February 2014 with rates effective on January 1, 2015 (see further discussion below).

(2) In its Order, the UTC found that much of the approved base rate increase was 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 settlement agreement, this could result in base rates which are considered too high by the UTC. We are required to 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. Total utility capital expenditures among all jurisdictions were $294.4 million and $323.9 million for 2013 and 2014 respectively. We expect utility capital expenditures to be about $375 million for 2015 and $350 million in 2016, which are above the capital expenditures contemplated in the settlement agreement.

2014 General Rate Cases

In November 2014, the UTC approved an all-party settlement agreement related to Avista Utilities' electric and natural gas general rate cases filed in February 2014 and new rates became effective on January 1, 2015. The settlement is designed to increase annual electric base revenues by $12.3 million, or 2.5 percent, inclusive of a $5.3 million power supply update as required in the settlement agreement (explained below). The settlement is designed to increase annual natural gas base revenues by $8.5 million, or 5.6 percent.

Expiring and New Rebates and Energy Recovery Mechanism (ERM)

The parties agreed in the settlement that a credit of $8.3 million from the ERM deferral balance will be returned to electric customers to help offset the 2015 rate increase. This ERM balance represents lower net power supply costs in recent years than the costs embedded in base retail rates, which are being returned to customers in the form of a rebate. This rebate will not increase or decrease our net income. Total net deferred power costs under the ERM were a liability of $14.2 million as of December 31, 2014, compared to a liability of $17.9 million as of December 31, 2013, and these deferred power cost balances represent amounts due to customers.

In addition, our electric customers were receiving benefits from two rebates that expired at the end of 2014 and which reduced monthly energy bills by 2.8 percent during 2014. The parties agreed in the settlement that we will provide a rebate to customers of $8.6 million over an 18 month period related to our sale of renewable energy credits, which will partially replace the expiring rebates and reduce customers’ monthly bills by 1.2 percent, beginning January 1, 2015. The net effect of the expiring rebates and the new rebate will result in an increase of approximately 1.6 percent beginning January 1, 2015. These rebates are passed through to customers and do not increase or decrease our net income.

The overall change in customer billing rates from the approved settlement agreement, including the expiring and new rebates, is 2.5 percent for electric customers and 5.6 percent for natural gas customers effective January 1, 2015.

Power Supply Update and Customer Information and Work Management Systems Deferral

The settlement agreement included a provision that required Avista Utilities to update base power supply costs on November 1, 2014. This update to power supply costs was reflected in the overall electric revenue increase effective January 1, 2015, and reset the base power supply costs for the ERM calculations effective January 1, 2015. The amount of the updated power supply costs was a $5.3 million increase. The increase to customers from the power supply update was offset with the available ERM deferral balance for the calendar year 2015. The use of the ERM deferral balance for the offset will not increase or decrease our net income.

The parties also agreed that the natural gas revenue requirement associated with our investment in the Customer Information and Work Management Systems capital project (Project Compass) for 2015 will be deferred for regulatory purposes for recovery in retail rates through a future general rate case, based on the actual costs of the project at the time it goes into service. Project Compass went into service in February 2015. The net income from the future recovery of these costs and return on investment, estimated to be $2.0 million on a pre-tax basis, will be recognized in the future recovery period.

Decoupling

The parties agreed that Avista Utilities will implement electric and natural gas decoupling mechanisms for a five-year period beginning January 1, 2015. Decoupling is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. Our actual revenue, based on kilowatt hour and therm sales will vary, up or down, from the level included in a general rate case. This could be due to changes in weather, conservation or the economy. Per the terms of the settlement agreement and the decoupling mechanisms included therein, generally, our electric and natural gas revenues will be adjusted each month to be based on the number of customers, rather than kilowatt hour and therm sales. The difference between revenues based on sales and revenues based on the number of customers will be deferred and either surcharged or rebated to customers beginning in the following year. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to 3 percent on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

The decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations will be made for the prior calendar year. These earnings tests will reflect actual decoupled revenues, normalized power supply costs, and other normalizing adjustments.

- If we have a decoupling rebate balance for the prior year and earn in excess of a 7.32 percent rate of return (ROR), the rebate to customers would be increased by 50 percent of the earnings in excess of the 7.32 percent ROR.
- If we have a decoupling rebate balance for the prior year and earn a 7.32 percent ROR or less, only the base amount of the rebate to customers would be made.
- If we have a decoupling surcharge balance for the prior year and earn in excess of a 7.32 percent ROR, the surcharge to customers would be reduced by 50 percent of the earnings in excess of the 7.32 percent ROR (or eliminated).
- If we have a decoupling surcharge balance for the prior year and earn a 7.32 percent ROR or less, the base amount of the surcharge to customers would be made.

Original Request

Our original request filed with the UTC in February 2014 included a base electric rate increase of 3.8 percent (designed to increase annual electric revenues by $18.2 million). We also requested a base natural gas rate increase of 8.1 percent (designed to increase annual natural gas revenues by $12.1 million). Specific capital structure ratios and the cost of capital components were not agreed to in the settlement agreement, and the revenue increases in the settlement were not tied to the 7.32 percent ROR referenced above. The electric and natural gas revenue increases were negotiated numbers, with each party using its own set of assumptions underlying its agreement to the revenue increases. The parties agreed that the 7.32 percent ROR will be used to calculate the Allowance for Funds Used During Construction (AFUDC) and other purposes.

2015 General Rate Cases

In February 2015, we filed electric and natural gas general rates cases with the UTC. We have requested an overall increase in base electric rates of 6.6 percent (designed to increase annual electric revenues by $33.2 million) and an overall increase in base natural gas rates of 7.0 percent (designed to increase annual natural gas revenues by $12.0 million). Our requests are based on a proposed ROR on rate base of 7.46 percent with a common equity ratio of 48 percent and a 9.9 percent return on equity.

The major driver of these general rate case requests is to recover the costs associated with the ongoing need to maintain, replace and invest in our facilities and equipment. Several significant capital investments we have made and are currently making, that are included in the filing are:

- the ongoing and multi-year redevelopment of the Little Falls hydroelectric plant on the Spokane River,
- the continuing rehabilitation of the Nine Mile hydroelectric plant on the Spokane River,
- information technology upgrades that include the replacement of our customer information and work management systems (which were implemented in February 2015),
- the ongoing project to systematically replace portions of Aldyl-A natural gas distribution pipe, and
- technology investments for deploying Advanced Metering Infrastructure in Washington, including installation of advanced meters, beginning in 2016.

The UTC has up to 11 months to review the filings and issue a decision.

Idaho General Rate Cases

2012 General Rate Cases

In March 2013, the IPUC approved a settlement agreement in Avista Utilities' electric and natural gas general rate cases filed in October 2012. As agreed to in the settlement, new rates were implemented in two phases: April 1, 2013 and October 1, 2013. Effective April 1, 2013, base rates increased for our Idaho natural gas customers by an overall 4.9 percent (designed to increase annual revenues by $3.1 million). There was no change in base electric rates on April 1, 2013. However, the settlement agreement provided for the recovery of the costs of the Palouse Wind Project through the PCA mechanism, subject to the 90 percent customers/10 percent Company sharing ratio, until these costs are reflected in base retail rates in our next general rate case.

The settlement also provided that, effective October 1, 2013, base rates increased for our Idaho natural gas customers by an overall 2.0 percent (designed to increase annual revenues by $1.3 million). A credit resulting from deferred natural gas costs of

$1.6 million was 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 was 0.3 percent.

Further, the settlement provided that, effective October 1, 2013, base rates increased for our Idaho electric customers by an overall 3.1 percent (designed to increase annual revenues by $7.8 million). A $3.9 million credit resulting from a payment made to us by the BPA relating to its prior use of our transmission system was 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 was 1.9 percent.

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

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

The settlement also included an after-the-fact earnings test for 2013 and 2014, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earns more than a 9.8 percent return on equity, we will share with customers 50 percent of any earnings above the 9.8 percent. In 2013, our returns exceeded this level and we deferred for future ratemaking treatment $3.9 million for Idaho electric customers and $0.4 million for Idaho natural gas customers. Of the electric deferral amount, $2.0 million was recorded in 2013 and $1.9 million was recorded in the first quarter of 2014 based on a revision of the allocation of costs between Idaho and Washington for regulatory purposes. The ratemaking treatment for these deferrals is addressed in the 2014 rate plan extension request explained below. There is no provision for a surcharge to customers if our return on equity is less than 9.8 percent.

In 2014, our returns exceeded a 9.8 percent return on equity and we deferred for future ratemaking treatment $5.6 million for Idaho electric customers, exclusive of the $1.9 million related to 2013 that was recorded in 2014, and $0.2 million for Idaho natural gas customers.

2014 Rate Plan Extension

Avista Utilities did not file new general rate cases in Idaho in 2014, instead, we developed an extension to the 2013 and 2014 rate plan and reached a settlement agreement with all interested parties.

In September 2014, the IPUC approved our settlement, which reflects agreement among all interested parties, for a one-year extension to our current rate plan, which was set to expire on December 31, 2014. Under the approved extension, base retail rates will remain unchanged through December 31, 2015.

The settlement will provide an estimated $3.7 million increase in pre-tax income by reducing planned expenses in 2015 for our Idaho operations, resulting from:

- the delay of the beginning of the amortization of the 2013 previously deferred operations and maintenance costs pertaining to the Colstrip and Coyote Springs 2 thermal generating facilities from 2015 to 2016, and
- deferred accounting, for later review and recovery, of the majority of the costs associated with Project Compass, which was implemented in February 2015.

The settlement agreement establishes an ROE deadband between the currently authorized ROE of 9.8 percent and a 9.5 percent ROE. Under the settlement agreement, we will be allowed to use any 2014 Idaho after-the-fact earnings test deferral (described above under "2012 General Rate Cases") to support an actual earned ROE in 2015 up to 9.5 percent. For 2014, we deferred a total of $7.7 million for the 2014 after-the-fact earnings test, which includes the $1.9 million recorded in 2014 related to the 2013 earnings test. During 2015, if we earn more than the 9.8 percent ROE, 50 percent of the earnings above 9.8 percent will be shared with customers through future ratemaking.

As part of the settlement, we agreed not to file a general rate case in 2014, and would file no earlier than May 31, 2015 for new electric or natural gas base retail rates to become effective on or after January 1, 2016. In addition, the settlement replaced two rebates, which expired on January 1, 2015, that were reducing customers' monthly energy bills by 1.3 percent for electric and 1.7 percent for natural gas. The rebates were replaced for a one-year period, through December 31, 2015, using existing deferral balances due to customers, which will have no impact on our net income. This provision does not preclude us from filing other rate adjustments such as the PGA.

In addition to the GRCs above, we are evaluating the need to file electric and natural gas GRCs with the IPUC sometime during 2015.

Oregon General Rate Cases

2013 General Rate Case

In January 2014, the OPUC approved a settlement agreement to Avista Utilities' natural gas general rate case (originally filed in August 2013). As agreed to in the settlement, new rates were implemented in two phases: February 1, 2014 and November 1, 2014. Effective February 1, 2014, rates increased for Oregon natural gas customers on a billed basis by an overall 4.4 percent (designed to increase annual revenues by $3.8 million). Effective November 1, 2014, rates for Oregon natural gas customers were to increase on a billed basis by an overall 1.6 percent (designed to increase annual revenues by $1.4 million).

The billed rate increase on November 1, 2014 was dependent upon the completion of Project Compass and the actual costs incurred through September 30, 2014, and the actual costs incurred through June 30, 2014 related to the Company's Aldyl A distribution pipeline replacement program. As noted elsewhere, Project Compass was completed in February 2015. The November 1, 2014 rate increase was reduced from $1.4 million to $0.3 million due to the delay of Project Compass.

The approved settlement agreement provides for an overall authorized rate of return of 7.47 percent, with a common equity ratio of 48 percent and a 9.65 percent return on equity.

2014 General Rate Case

In January 2015, Avista Utilities filed an all-party settlement agreement with the OPUC related to our natural gas general rate case, which was originally filed in September 2014. The settlement agreement was designed to increase base natural gas revenues by 6.1 percent or $6.1 million. This base rate increase was offset by $0.3 million for a separate rate adjustment that we are already receiving from customers and it was offset by a $0.8 million credit to customers related to having an early implementation date for the revenue increase (prior to the full 10 months allowed in Oregon for the OPUC to make a decision on the case and new rates to take effect). The net increase to revenue after the two offsets was $5.0 million. The parties to the settlement had requested a decision by the OPUC prior to March 1, 2015, such that new retail rates could be effective on March 1, 2015.

This settlement agreement provided for an overall authorized rate of return of 7.52 percent with a common equity ratio of 51 percent and a 9.5 percent return on equity.

The original request was for an overall increase in base natural gas rates of 9.3 percent (designed to increase annual natural gas revenues by $9.1 million) and it was based on a proposed rate of return of 7.77 percent with a common equity ratio of 51 percent and a 9.9 percent return on equity.

On February 23, 2015, the OPUC issued an order rejecting the all-party settlement agreement filed with the OPUC by the parties on January 21, 2015. The OPUC expressed concerns related to three issues: 1) the proposed early rate implementation credit; 2) the combination of proposed rate increases and rate decreases across the customer classes (rate spread); and 3) the customer count tracking mechanism. With regard to the early rate implementation credit, the order stated, among other things, that there was no evidence in the record that explains the derivation of the rate credit amount, or why the credit would be applied to all customer classes. On rate spread, the OPUC’s order expressed concern about proposed increases to rates for some customer classes, and decreases for other customer classes, absent more compelling evidence. And finally, the OPUC expressed concern that the customer count tracking mechanism is contrary to standard ratemaking.

The OPUC’s order directed the Administrative Law Judge to convene a prehearing conference to schedule further proceedings in a manner that will allow for the timely completion of the case. The OPUC’s order also encouraged the parties to come back with a partial stipulation that encompasses these issues. Furthermore, the OPUC stated that its order does not preclude the parties from reaching a global settlement of all issues that addresses the concerns identified by the OPUC.

In addition to the GRCs above, we are evaluating the need to file a natural gas GRC with the OPUC sometime during 2015.

Alaska General Rate Case

AEL&P's last GRC was filed in 2010 and approved by the RCA in 2011.

Bonneville Power Administration Reimbursement and Reardan Wind Generation Project

In May 2013, the UTC approved Avista Utilities' Petition for an order authorizing certain accounting and ratemaking treatment related to two issues. The first issue related to transmission revenues associated with a settlement between Avista Corp. and the BPA, whereby the BPA reimbursed us $11.7 million in the first quarter of 2013 for the BPA's past use of our transmission system. The second issue related to $4.3 million of costs we incurred for the development of a wind generation project site near Reardan, Washington, which was terminated. The UTC authorized us to retain $7.6 million of the BPA settlement payment in 2013, representing the entire portion of the settlement allocable to our Washington business. However, this amount was deemed to first reimburse the Company for the $2.5 million of Reardan project costs that were allocable to our Washington business, leaving $5.1 million which was retained for the benefit of shareholders in 2013.

The BPA agreed to pay $3.2 million annually for the future use of our transmission system. We separately tracked and deferred for the customers' benefit, the Washington portion of these revenue payments in 2013 and 2014 ($2.1 million annually). We implemented a one-year $4.2 million rate decrease for customers effective January 1, 2014 to partially offset our electric general rate increase effective January 1, 2014. To the extent actual revenues from the BPA in 2013 and 2014 differ from those refunded to customers in 2014, the difference will be added to or subtracted from the ERM balance. In Idaho, under the terms of the approved rate case settlement, 90 percent of the portion of the BPA settlement allocable to our Idaho business ($4.1 million) was credited back to customers over 15 months, beginning October 2013, and we are amortizing the Idaho portion of Reardan costs ($1.7 million, including $1.3 million of incurred costs and $0.4 million of equity-related AFUDC) over a two-year period, beginning April 2013.

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to Avista Utilities' customers with no change in gross margin (operating revenues less resource costs) or net income. In Oregon, we absorb (cost or benefit) 10 percent of the difference between actual and projected gas costs included in retail rates for supply that is not hedged. Total net deferred natural gas costs among all jurisdictions were a liability of $3.9 million as of December 31, 2014 and a liability of $12.1 million as of December 31, 2013.

The following PGAs went into effect in our various jurisdictions during 2012, 2013 and 2014:

Jurisdiction	PGA Effective Date	Percentage Increase / (Decrease) in Billed Rates
Washington	March 1, 2012	(6.4)%
	November 1, 2012	(4.4)%
	November 1, 2013	9.2%
	November 1, 2014	1.2%
Idaho	March 1, 2012	(6.0)%
	October 1, 2012	(3.1)%
	October 1, 2013	7.5%
	November 1, 2014	(2.1)%
Oregon	November 1, 2012 (1)	(7.5)%
	January 1, 2013 (1)	(0.8)%
	November 1, 2013	(7.9)%
	November 1, 2014	8.3%

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

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used to track certain differences between Avista Utilities' actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for our Washington customers. Total net deferred power costs under the ERM were a liability of $14.2 million as of December 31, 2014 compared to $17.9 million as of December 31, 2013, and these deferred power cost balances represent amounts due to customers. As part of the approved Washington general rate case settlement in December 2012, during 2013 there was a one-year credit designed to return $4.4 million 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 there was a one-year credit designed to return $9.0 million to electric customers from the ERM deferral balance, so the net average electric rate increase impact to customers effective January 1, 2014 was also reduced. The credits to customers from the ERM balances do 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 and availability of hydroelectric generation,
- the level and availability of thermal generation (including changes in fuel prices), and
- retail loads.

Under the ERM, Avista Utilities 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 $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, Avista Utilities makes 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. We made our annual filing on March 31, 2014, and as part of the UTC staff's review of the filing, the staff reviewed the prudence of the Colstrip outage from July 2013 through January 2014. UTC staff found no imprudence by Avista Corp. related to the Colstrip outage and recommended approval of all the ERM related transactions for 2013. 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. The 2013 ERM deferred power costs transactions were approved by an order from the UTC.

Avista Utilities has 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 an asset of $8.3 million as of December 31, 2014 compared to an asset of $5.1 million as of December 31, 2013.

Results of Operations - Overall

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, AEL&P, Ecova - Discontinued Operations and the other businesses) that follow this section.

As discussed in "Item 7. Management's Discussion and Analysis: Executive Level Summary," Ecova was disposed of as of June 30, 2014. As a result, in accordance with Generally Accepted Accounting Principles (GAAP), all of Ecova's operating results were removed from each line item on the Consolidated Statements of Income and reclassified into discontinued operations for all periods presented. The discussion of continuing operations below does not include any Ecova amounts. For our discussion of discontinued operations and Ecova, see "Item 7. Management's Discussion and Analysis: Ecova - Discontinued Operations."

The balances included below for utility operations reconcile to the Consolidated Statements of Income. Beginning on July 1, 2014, AEL&P is included in the overall utility results.

2014 compared to 2013

Utility revenues increased $31.1 million, after elimination of intracompany revenues (within Avista Utilities) of $142.2 million for 2014 and $151.9 million for 2013. Avista Utilities' portion of utility revenues increased $9.5 million and AEL&P had electric revenues of $21.6 million, representing its revenues for the six months ended December 31, 2014. Including intracompany revenues, Avista Utilities' electric revenues decreased $31.6 million and natural gas revenues increased $31.4 million. Total retail electric revenues increased $14.8 million primarily due to general rate increases and a change in revenue mix, with a greater percentage of retail revenue from residential and commercial customers. This was partially offset by a decrease in retail sales volumes. Wholesale electric revenues increased $10.6 million due to an increase in sales prices partially offset by a decrease in sales volumes, while sales of fuel decreased $42.9 million. Other electric revenues decreased $8.6 million primarily due to the receipt of $11.7 million of revenue from the BPA in the first quarter of 2013 for past use of our electric transmission system. In 2014, we estimated a provision for earnings sharing of $7.5 million for Idaho electric customers with $5.6 million representing our estimate for 2014 and $1.9 million representing an adjustment of our 2013 estimate. In 2013, we recorded a provision for earnings sharing of $2.0 million for Idaho electric customers. Retail natural gas revenues decreased $1.3 million due to a decrease in volumes caused by warmer than normal weather during the fourth quarter, partially offset by an increase in retail rates. Wholesale natural gas revenues increased $33.5 million due to an increase in prices and volumes.

Utility resource costs decreased $11.3 million, after elimination of intracompany resource costs of $142.2 million for 2014 and $151.9 million for 2013. Avista Utilities' portion of resource costs decreased $17.2 million and this was offset by utility resource costs at AEL&P of $5.9 million, representing its resource costs for the six months ended December 31, 2014. Including intracompany resource costs, Avista Utilities' electric resource costs decreased $57.7 million and natural gas resource costs increased $30.7 million. The decrease in Avista Utilities' electric resource costs was due to the Colstrip outage in 2013 and increased hydroelectric generation in 2014. Specifically, there were decreases in purchased power, fuel for generation and other fuel costs (represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation as part of the resource optimization process). The increase in natural gas resource costs was primarily due to an increase in natural gas purchased, partially offset by a decrease in natural gas cost amortizations.

Utility other operating expenses increased $10.6 million and was partially the result of AEL&P being included for the six months ended December 31, 2014, which added $5.9 million to other operating expenses. Avista Utilities incurred increased generation, transmission and distribution operating and maintenance expenses and increased outside services. There were also transaction fees associated with the AERC acquisition of $1.3 million in 2014 compared to $1.6 million in 2013. These were partially offset by a decrease in pension and other post-retirement benefits expense.

Utility depreciation and amortization increased $12.4 million driven by additions to utility plant and the inclusion of $2.6 million related to AEL&P for the second half of the year.

Taxes other than income taxes increased $5.9 million primarily due to increased production, distribution and transmission property taxes. Also, 2014 included $1.1 million related to AEL&P for the second half of the year.

Other non-utility operating expenses decreased $8.2 million primarily due to the receipt of $15.0 million related to the settlement of the California power markets litigation (which was recorded as a reduction to operating expenses), partially offset by a $6.4 million contribution to the Avista Foundation.

Interest expense decreased $1.8 million primarily due to the long-term debt outstanding during 2014 having a lower interest rate than the long-term debt outstanding during 2013. This includes recent issuances at low interest rates. This was partially offset by the acquisition of AERC, which added $1.4 million for the second half of 2014.

Other income-net increased $6.2 million primarily due to net income from investments of $0.3 million compared to net losses of $3.4 million in 2013. The net losses in 2013 were the result of impairment losses associated with our investment in an energy storage company and our investment in a fuel cell business. There was also an increase in equity-related AFUDC of $2.7 million during 2014.

Income taxes increased $14.2 million and our effective tax rate was 37.6 percent for 2014 compared to 35.7 percent for 2013. The increase in expense was primarily due to an increase in income before income taxes. The increase in the effective tax rate was primarily the result of the Section 199 Domestic Manufacturing Deduction not being available to the Company due to limitations on taxable qualified production activities income.

2013 compared to 2012

Utility revenues increased $49.8 million, after elimination of intracompany revenues of $151.9 million for 2013 and $88.2 million for 2012. Including intracompany revenues, electric revenues increased $62.4 million and natural gas revenues increased $51.1 million. Total retail electric revenues increased $13.8 million due to general rate increases and an increase in volumes sold, which was primarily the result of warmer than normal weather during the cooling season and colder than normal weather during the fourth quarter heating season. Wholesale electric revenues increased $24.8 million and sales of fuel increased $10.8 million. Other electric revenues increased $15.0 million primarily due to the receipt of revenue from the BPA for past use of our electric transmission system. Retail natural gas revenues increased $13.3 million due to an increase in volumes caused by colder than normal weather during the fourth quarter, partially offset by a decrease in retail rates. Wholesale natural gas revenues increased $36.1 million due to an increase in prices, partially offset by a decrease in volumes.

Utility resource costs decreased $3.5 million, after elimination of intracompany resource costs of $151.9 million for 2013 and $88.2 million for 2012. Including intracompany resource costs, electric resource costs increased $24.8 million and natural gas resource costs increased $35.4 million. The increase in electric resource costs was primarily due to an increase in fuel costs (due to higher natural gas generation and higher natural gas fuel prices), 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 write-off of $2.5 million of Reardan project costs that are allocable to our Washington business. The increase in natural gas resource costs was primarily due to an increase in natural gas prices, partially offset by a decrease in volumes (primarily attributable to wholesale sales).

Utility other operating expenses decreased $0.6 million primarily as a result of a decrease in administrative and general labor expenses (which included $7.3 million of costs to implement the voluntary severance incentive plan in 2012 only) and a decrease in generation maintenance expenses. These decreases were partially offset by increases in pension and other postretirement benefit expenses and electric, production and gas distribution related operating and maintenance expenses.

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

Taxes other than income taxes increased $5.0 million primarily due to increased franchise, municipal, and property related taxes.

Interest expense increased $2.0 million primarily due to the issuance of long-term debt in November 2012 that increased the amount of long-term debt outstanding.

Capitalized interest increased $1.3 million primarily due to higher average construction work in progress balances.

Other income-net increased $2.5 million primarily due to an increase in equity-related AFUDC of $2.0 million. In addition, during 2013 we incurred impairment losses of $3.4 million ($2.2 million after-tax) associated with our investment in an energy storage company and our investment in a fuel cell business. During 2012, we incurred total losses on investments of $3.3 million, which included impairment losses of $2.4 million ($1.5 million after-tax) related to our investment in a fuel cell business and the write-off of our investment in a solar energy company.

Income taxes increased $18.3 million and our effective tax rate was 35.7 percent for 2013 compared to 34.1 percent for 2012. The increase in expense was primarily due to an increase in income before income taxes. The change in the effective tax rate was primarily related to a reduction in the amount of our pension contribution deduction.

Results of Operations - 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 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.

2014 compared to 2013

Net income for Avista Utilities was $113.3 million for 2014, an increase from $108.6 million for 2013. Avista Utilities’ income from operations was $240.0 million for 2014 compared to $232.6 million for 2013. Earnings at Avista Utilities increased primarily due to the implementation of general rate increases, lower net power supply costs and a decrease in interest expense. These were partially offset by a provision for earnings sharing in Idaho, and expected increases in other operating expenses, depreciation and amortization and taxes other than income taxes.

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

	Electric		Natural Gas		Intracompany		Total	
	2014	2013	2014	2013	2014	2013	2014	2013
Operating revenues	$ 998,988	$ 1,030,606	$ 556,664	$ 525,259	$ (142,153)	$ (151,870)	$ 1,413,499	$ 1,403,995
Resource costs	418,541	476,226	395,956	365,230	(142,153)	(151,870)	672,344	689,586
Gross margin	$ 580,447	$ 554,380	$ 160,708	$ 160,029	$ —	$ —	$ 741,155	$ 714,409

Avista Utilities' operating revenues increased $9.5 million and resource costs decreased $17.2 million, which resulted in an increase of $26.7 million in gross margin. The gross margin on electric sales increased $26.0 million and the gross margin on natural gas sales increased $0.7 million. The increase in electric gross margin was primarily due to general rate increases in Washington and Idaho and lower net power supply costs (due to the Colstrip outage in 2013 and increased hydroelectric generation in 2014). This was partially offset by a $7.5 million provision for earnings sharing in Idaho in 2014, compared to $2.0 million in 2013. For 2014, we recognized a pre-tax benefit of $5.4 million under the ERM in Washington compared to a pre-tax expense of $4.7 million for 2013. This change represents a decrease in net power supply costs due to the Colstrip outage in 2013 and increased hydroelectric generation in 2014. Electric gross margin for 2013 included the net benefit from the settlement with the BPA of $5.1 million. The increase in natural gas gross margin was primarily due to general rates increases, mostly offset by warmer weather during the fourth quarter of 2014.

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	
	2014	2013	2014	2013
Residential	$ 338,697	$ 331,867	3,694	3,745
Commercial	300,109	289,604	3,189	3,147
Industrial	110,775	113,632	1,868	1,979
Public street and highway lighting	7,549	7,267	25	26
Total retail	757,130	742,370	8,776	8,897
Wholesale	138,162	127,556	3,686	3,874
Sales of fuel	83,732	126,657	—	—
Other	27,467	36,071	—	—
Provision for earnings sharing	(7,503)	(2,048)	—	—
Total	$ 998,988	$ 1,030,606	12,462	12,771

Retail electric revenues increased $14.8 million due to an increase in revenue per MWh (increased revenues $25.2 million), partially offset by a decrease in total MWhs sold (decreased revenues $10.4 million). The increase in revenue per MWh was primarily due to general rate increases and a change in revenue mix, with a greater percentage of retail revenue from residential and commercial customers.

The decrease in total MWhs sold to residential customers was primarily due to warmer weather in the fourth quarter, partially offset by customer growth. Compared to 2013, residential electric use per customer decreased 2.3 percent, while commercial use per customer decreased 0.6 percent. Cooling degree days at Spokane were 60 percent above historical average for 2014, but 11 percent below 2013. Heating degree days at Spokane were 9 percent below historical average for 2014, and 7 percent below 2013.

The decrease in total MWhs sold to industrial customers was primarily due to the expiration and replacement of a contract with one of our largest industrial customers, effective July 1, 2013. Under the new contract, we expect a decrease in revenues from annual power sales to this customer of approximately $21 million and a resulting decrease in resource costs of approximately $19 million. Any change in revenues and expenses associated with the new agreement, as compared with the revenues and expenses included in the last general rate case for this customer, are tracked through the PCA in Idaho at 100 percent, until such time as the contract is included in the Company's base rates, so that we expect no impact on our gross margin or net income from the new agreement.

Wholesale electric revenues increased $10.6 million due to an increase in sales prices (increased revenues $17.6 million), partially offset by a decrease in sales volumes (decreased revenues $7.0 million). The fluctuation in volumes and prices was primarily the result of our optimization activities during the period.

When current and forward electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the related natural gas purchased for generation in the wholesale market rather than operate the generating units. The revenues from sales of fuel decreased $42.9 million due to a decrease in sales of natural gas fuel as part of thermal generation resource optimization activities. These thermal optimization transactions also include forward hedges using derivative instruments for electricity and natural gas. As relative power and natural gas prices vary, our volume of thermal optimization also varies. For 2014, $67.4 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For 2013, $102.4 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.

Other electric revenues decreased $8.6 million primarily due to the receipt of $11.7 million of revenue from the BPA in 2013 for past use of our electric transmission system. See further information above at "Bonneville Power Administration Reimbursement and Reardan Wind Generation Project."

The 2013 Idaho general rate case settlement included 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, earned more than a 9.8 percent return on equity, we would share with customers 50 percent of any earnings above the 9.8 percent. In 2014, we estimated a provision for earnings sharing of $7.5 million for Idaho electric customers with $5.6 million representing our estimate for 2014 and $1.9 million representing an adjustment of our 2013 estimate. In 2013, we recorded a provision for earnings sharing of $2.0 million for Idaho electric customers. There is no provision for a surcharge to customers if our return on equity is less than 9.8 percent.

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	
	2014	2013	2014	2013
Residential	$ 203,373	$ 206,330	190,171	204,711
Commercial	103,179	102,225	116,748	122,245
Interruptible	2,792	2,681	5,033	5,694
Industrial	4,158	3,599	5,648	5,181
Total retail	313,502	314,835	317,600	337,831
Wholesale	228,187	194,717	545,620	524,818
Transportation	7,735	7,576	162,311	159,976
Other	7,461	8,573	411	418
Provision for earnings sharing	(221)	(442)	—	—
Total	$ 556,664	$ 525,259	1,025,942	1,023,043

Retail natural gas revenues decreased $1.3 million due to a decrease in volumes (decreased revenues $20.0 million), partially offset by higher retail rates (increased revenues $18.7 million). Higher retail rates were due to PGAs, which passed through higher costs of natural gas, and general rate cases. We sold less retail natural gas in 2014 as compared to 2013 primarily due to weather that was warmer than normal and warmer than the prior year during the fourth quarter. Compared to 2013, residential use per customer decreased 8 percent and commercial use per customer decreased 5 percent. Heating degree days at Spokane were 9 percent below historical average for 2014, and 7 percent below 2013. Heating degree days at Medford were 25 percent below historical average for 2014, and 26 percent below 2013. For the fourth quarter of 2014, heating degree days at Spokane were 13 percent below historical average and 16 percent below 2013. Heating degree days at Medford were 29 percent below historical average and 36 percent below 2013.

Wholesale natural gas revenues increased $33.5 million due to an increase in prices (increased revenues $24.8 million) and an increase in volumes (increased revenues $8.7 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 2014, $74.7 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In 2013, $49.5 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.

Based on the after-the-fact earnings test related to the 2013 Idaho general rate case settlement discussed above, our 2014 consolidated earnings exceeded the 9.8 percent return on equity for Idaho and we recorded a provision for earnings sharing of $0.2 million for Idaho natural gas customers.

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	
	2014	2013	2014	2013
Residential	324,188	321,098	291,928	288,708
Commercial	40,988	40,202	34,047	33,932
Interruptible	—	—	37	38
Industrial	1,385	1,386	264	259
Public street and highway lighting	531	527	—	—
Total retail customers	367,092	363,213	326,276	322,937

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

	2014	2013
Electric resource costs:		
Power purchased	$ 184,966	$ 189,930
Power cost amortizations, net	(6,546)	(14,192)
Fuel for generation	116,433	133,663
Other fuel costs	82,357	121,987
Other regulatory amortizations, net	20,711	22,734
Other electric resource costs	20,620	22,104
Total electric resource costs	418,541	476,226
Natural gas resource costs:		
Natural gas purchased	397,669	353,087
Natural gas cost amortizations, net	(8,065)	4,784
Other regulatory amortizations, net	6,352	7,359
Total natural gas resource costs	395,956	365,230
Intracompany resource costs	(142,153)	(151,870)
Total resource costs	$ 672,344	$ 689,586

Power purchased decreased $5.0 million due to a decrease in the volume of power purchases (decreased costs $25.4 million), partially offset by an increase in wholesale prices (increased costs $20.4 million). The fluctuation in volumes and prices was primarily the result of our overall optimization activities during the year. The decrease in volumes purchased was also due to increased hydroelectric generation.

Amortizations and deferrals of power costs decreased electric resource costs by $6.5 million for 2014 compared to a decrease of $14.2 million for 2013. During 2014, we refunded to customers $2.3 million of previously deferred power costs in Idaho through the PCA rebate. We also refunded to Washington customers $8.5 million through an ERM rebate. During 2014, actual power supply costs were below the amount included in base retail rates in Washington and we deferred $4.2 million for probable future benefit to customers. We deferred $1.6 million in Idaho for probable future surcharge to customers. In Washington, we also deferred $1.6 million of renewable energy credits for probable future benefit to customers.

Fuel for generation decreased $17.2 million primarily due to a decrease in natural gas generation (due in part to increased hydroelectric generation).

Other fuel costs decreased $39.6 million. This represents fuel and the related derivative instruments that were purchased for generation but were 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 or related derivative instruments are sold, that revenue is included in sales of fuel.

The expense for natural gas purchased increased $44.6 million due to an increase in the price of natural gas (increased costs $44.3 million) and a slight increase in total therms purchased (increased costs $0.3 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, mostly offset by a decrease in retail sales. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs.

2013 compared to 2012

Net income for Avista Utilities was $108.6 million for 2013, an increase from $81.7 million for 2012. Avista Utilities' income from operations was $232.6 million for 2013 compared to $188.8 million for 2012. Earnings at Avista Utilities increased primarily due to the implementation of general rate increases, favorable weather, the net benefit from the settlement with the BPA and a slight reduction in other operating expenses. These were partially offset by expected increases in depreciation and amortization and taxes other than income taxes.

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

	Electric		Natural Gas		Intracompany		Total	
	2013	2012	2013	2012	2013	2012	2013	2012
Operating revenues	$ 1,030,606	$ 968,172	$ 525,259	$ 474,173	$ (151,870)	$ (88,160)	$ 1,403,995	$ 1,354,185
Resource costs	476,226	451,434	365,230	329,853	(151,870)	(88,160)	689,586	693,127
Gross margin	$ 554,380	$ 516,738	$ 160,029	$ 144,320	$ —	$ —	$ 714,409	$ 661,058

Avista Utilities' operating revenues increased $49.8 million and resource costs decreased $3.5 million, which resulted in an increase of $53.3 million in gross margin. The gross margin on electric sales increased $37.6 million and the gross margin on natural gas sales increased $15.7 million. The increase in both electric and natural gas gross margin was due in part to general rate increases. The increase in electric gross margin was also due to warmer than normal weather and increased cooling loads during the summer, as well as colder than normal weather and increased heating loads during the fourth quarter. This is compared to milder weather in the prior year, particularly warmer than normal weather during the fourth quarter, which reduced loads during that period. In addition, electric gross margin increased due to the net benefit from the settlement with the BPA of $5.1 million. For 2013, we recognized a pre-tax expense of $4.7 million under the ERM in Washington compared to pre-tax benefit of $6.0 million for 2012. This change, which reduced electric gross margin, was primarily due to the Colstrip outage and partially due to lower hydroelectric generation and higher natural gas fuel prices as compared to 2012. The increase in natural gas gross margin was also due to colder than normal weather during the fourth quarter of 2013 as compared to the fourth quarter of 2012 and the increased heating loads. In addition to the above, our combined electric and natural gas earnings in Idaho for 2013 exceeded the 9.8 percent allowed return on equity as specified in the 2013 general rate case settlement, and, as a result, we recorded a provision for earnings sharing of $2.0 million for Idaho electric customers and $0.4 million for Idaho natural gas customers.

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	
	2013	2012	2013	2012
Residential	$ 331,867	$ 315,137	3,745	3,608
Commercial	289,604	286,568	3,147	3,127
Industrial	113,632	119,589	1,979	2,100
Public street and highway lighting	7,267	7,240	26	26
Total retail	742,370	728,534	8,897	8,861
Wholesale	127,556	102,736	3,874	3,733
Sales of fuel	126,657	115,835	—	—
Other	36,071	21,067	—	—
Provision for earnings sharing	(2,048)	—	—	—
Total	$ 1,030,606	$ 968,172	12,771	12,594

Retail electric revenues increased $13.8 million due to an increase in revenue per MWh (increased revenues $10.8 million) and an increase in total MWhs sold (increased revenues $3.0 million).

The increase in total MWhs sold was primarily the result of warmer than normal weather during the cooling season, as well as colder than normal weather during the fourth quarter heating season. Compared to 2012, residential electric use per customer increased 3 percent. Cooling degree days at Spokane were 80 percent above historical average for 2013 and were 33 percent above 2012. Heating degree days at Spokane were 1 percent below historical average for 2013, and 7 percent above 2012.

The decrease in total MWhs sold to industrial customers was primarily due to a renewed contract which replaced an expired contract at one of our largest industrial customers which became effective July 1, 2013, partially offset by increased usage at certain industrial customers that had temporary operational challenges in 2012. Any change in revenues and expenses associated with the new agreement, as compared with the revenues and expenses included in the last general rate case for this customer, are tracked through the PCA in Idaho at 100 percent, until such time as the contract is included in the Company's base rates, so that there was no impact on our gross margin or net income from the new agreement.

The increase in revenue per MWh was primarily due to a change in revenue mix, with a greater percentage of retail revenue from residential and commercial customers, and the Washington general rate increase, partially offset by other rate changes that do not impact gross margin (including the ERM rebate).

Wholesale electric revenues increased $24.8 million due to an increase in sales volumes (increased revenues $4.7 million) and an increase in sales prices (increased revenues $20.1 million), which were related to an increase in optimization activities.

When current and forward electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the related natural gas purchased for generation in the wholesale market rather than operate the generating units. The revenues from sales of fuel increased $10.8 million due to an increase in sales of natural gas fuel as part of thermal generation resource optimization activities, as well as an increase in natural gas prices. These thermal optimization transactions also include forward hedges using derivative instruments for electricity and natural gas. As relative power and natural gas prices vary, our volume of thermal optimization also varies. For 2013, $102.4 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For 2012, $45.3 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.

Other electric revenues increased $15.0 million primarily due to the receipt of $11.7 million of revenue from the BPA for past use of our electric transmission system.

In 2013, our returns exceeded the 9.8 percent return on equity that was allowed in the 2013 Idaho general rate case settlement (discussed above) and we recorded a provision for earnings sharing of $2.0 million for Idaho electric customers.

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	
	2013	2012	2013	2012
Residential	$ 206,330	$ 196,719	204,711	189,152
Commercial	102,225	98,994	122,245	115,083
Interruptible	2,681	2,232	5,694	4,363
Industrial	3,599	3,635	5,181	5,073
Total retail	314,835	301,580	337,831	313,671
Wholesale	194,717	158,631	524,818	586,193
Transportation	7,576	7,032	159,976	154,704
Other	8,573	6,930	418	381
Provision for earnings sharing	(442)	—	—	—
Total	$ 525,259	$ 474,173	1,023,043	1,054,949

Retail natural gas revenues increased $13.3 million due to an increase in volumes (increased revenues $22.5 million), partially offset by lower retail rates (decreased revenues $9.2 million). We sold more retail natural gas in 2013 as compared to 2012 primarily due to colder than normal weather during the fourth quarter. Compared to 2012, residential use per customer increased 7 percent and commercial use per customer increased 6 percent. Heating degree days at Spokane were 1 percent below historical average for 2013, and 7 percent above 2012. Heating degree days at Medford were 1 percent above historical average for 2013, and 9 percent above 2012. For the fourth quarter of 2013, heating degree days at Spokane were 3 percent above historical average and 16 percent above 2012. Heating degree days at Medford were 12 percent above historical average and 29 percent above 2012.

Wholesale natural gas revenues increased $36.1 million due to an increase in prices (increased revenues $58.9 million), partially offset by a decrease in volumes (decreased revenues $22.8 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 2013, $49.5 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In 2012, $42.9 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.

Based on the after-the-fact earnings test related to the 2013 Idaho general rate case settlement discussed above, our 2013 consolidated earnings exceeded the allowed return on equity for Idaho and we recorded a provision for earnings sharing of $0.4 million for Idaho natural gas customers.

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	
	2013	2012	2013	2012
Residential	321,098	318,692	288,708	286,522
Commercial	40,202	39,869	33,932	33,763
Interruptible	—	—	38	38
Industrial	1,386	1,395	259	263
Public street and highway lighting	527	503	—	—
Total retail customers	363,213	360,459	322,937	320,586

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

	2013	2012
Electric resource costs:		
Power purchased	$ 189,930	$ 194,088
Power cost amortizations, net	(14,192)	12,784
Fuel for generation	133,663	90,029
Other fuel costs	121,987	120,074
Other regulatory amortizations, net	22,734	15,665
Other electric resource costs	22,104	18,794
Total electric resource costs	476,226	451,434
Natural gas resource costs:		
Natural gas purchased	353,087	327,458
Natural gas cost amortizations, net	4,784	(5,804)
Other regulatory amortizations, net	7,359	8,199
Total natural gas resource costs	365,230	329,853
Intracompany resource costs	(151,870)	(88,160)
Total resource costs	$ 689,586	$ 693,127

Power purchased decreased $4.2 million due to a decrease in wholesale prices (decreased costs $6.6 million), partially offset by an increase in the volume of power purchases (increased costs $2.4 million).

Amortization and deferrals of power costs decreased electric resource costs by $14.2 million for 2013 compared to an increase of $12.8 million for 2012. During 2013, we refunded to customers $3.3 million of previously deferred power costs in Idaho through the PCA rebate. As part of the Washington general rate case settlement implemented on January 1, 2013, we refunded to customers $4.0 million through an ERM rebate. During 2013, actual power supply costs were above the amount included in base retail rates and we deferred $1.2 million in Washington and $6.9 million in Idaho for probable future surcharge to customers. In Washington, we also deferred $1.2 million of renewable energy credits for probable future rebate to customers.

Fuel for generation increased $43.6 million due to an increase in natural gas generation and an increase in natural gas fuel prices. Generation at Colstrip decreased due to an outage at Unit 4.

Other fuel costs increased $1.9 million. This represents fuel and the related derivative instruments that were purchased for generation but were 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 or related derivative instruments are sold, that revenue is included in sales of fuel.

The expense for natural gas purchased increased $25.6 million due to an increase in the price of natural gas (increased costs $40.8 million), partially offset by a decrease in total therms purchased (decreased costs $15.2 million). Total therms purchased decreased due to a decrease in wholesale sales volumes which are used to balance loads and resources as part of the natural gas procurement and resource optimization process, partially offset by a slight increase in retail sales. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs.

Results of Operations - Alaska Electric Light and Power Company

As noted above, AEL&P was acquired on July 1, 2014 and only the results for the second half of 2014 are included in the actual overall results of Avista Corp. The discussion below is only for AEL&P's earnings that were included in Avista Corp.'s overall earnings in 2014.

2014

Net income for AEL&P was $3.2 million for the second half of 2014.

The following table presents AEL&P's operating revenues, resource costs and resulting gross margin for the second half of 2014 (dollars in thousands):

	Electric
Operating revenues	$ 21,644
Resource costs	5,900
Gross margin	$ 15,744

The following table presents AEL&P's utility electric operating revenues and megawatt-hour (MWh) sales for the second half of 2014 (dollars and MWhs in thousands):

	Electric Operating Revenues	Electric Energy MWh sales
Residential	$ 8,283	63
Commercial and government	12,948	125
Public street and highway lighting	150	1
Total retail	21,381	189
Other	263	—
Total	$ 21,644	189

AEL&P’s operating revenues were $21.6 million and its resource costs were $5.9 million, which resulted in gross margin of $15.7 million, all related to electric sales. Retail revenues for the current period were derived from weather that was warmer than normal with heating degree days that were 9 percent below normal. There were no cooling degree days during the second half of 2014. AEL&P is winter peaking and does not have significant cooling loads during the summer. Government sales are similar to commercial sales in that they are primarily firm customers, but are government entities.

Commercial and government revenues from interruptible or non-firm customers were $4.1 million, including $3.5 million from AEL&P's largest customer. These non-firm revenues reduce firm revenues, either through base rates or a cost of power adjustment. For the second half of 2014, the cost of power adjustment was a net rebate to firm customers of $0.6 million (included in resource costs).

The following table presents AEL&P's average number of electric retail customers for the second half of 2014:

	Electric Customers
Residential	14,121
Commercial and government	2,148
Public street and highway lighting	213
Total retail customers	16,482

The following table presents AEL&P's utility resource costs for the second half of 2014 (dollars in thousands):

	Resource Costs
Snettisham power expenses	$ 5,196
Cost of power adjustment, net	646
Fuel for generation	58
Total electric resource costs	$ 5,900

Snettisham power expenses represent costs associated with operating the Snettisham hydroelectric project, including amounts paid under the take-or-pay power purchase agreement for the full capacity of this plant. This agreement is recorded as a capital lease on AEL&P's balance sheet, but reflected as an operating lease in the income statement. See "Note 14 of the Notes to Consolidated Financial Statements" for further information regarding this capital lease obligation.

The cost of power adjustment is primarily derived from certain revenues from interruptible or non-firm customers that are deferred and passed on for the benefit of firm customers in future periods. For instance, all cruise ship revenue is passed back to firm customers at 100 percent. The amortization of these deferred balances flows through this account along with the original deferral.

Results of Operations - Ecova - Discontinued Operations

As discussed in "Item 7. Management's Discussion and Analysis: Executive Level Summary," Ecova was disposed of as of June 30, 2014. As a result, in accordance with GAAP, all of Ecova's operating results were removed from each line item on the Consolidated Statements of Income and reclassified into discontinued operations for all periods presented. In addition, since Ecova was a subsidiary of Avista Capital, the net gain recognized on the sale of Ecova was attributable to our other businesses. However, in accordance with GAAP, this gain is included in discontinued operations; therefore, we included the analysis of the gain in the Ecova discontinued operations section rather than in the other businesses section.

2014 compared to 2013

Ecova's net income attributable to Avista Corp. shareholders was $72.4 million for 2014 compared to net income of $7.1 million for 2013. The increase was primarily attributable to the net gain recognized on the sale of Ecova of $69.7 million. Excluding the net gain, net income from Ecova's regular operations through the date of the sale were flat compared to the same period in 2013 and were the result of a decrease in depreciation and amortization expense, an increase in operating revenues, offset by an increase in operating expenses.

2013 compared to 2012

Ecova's net income attributable to Avista Corp. shareholders was $7.1 million for 2013 compared to net income of $1.8 million for 2012. The increase was primarily attributable to increased revenues from new services that were performed by Ecova during 2013, growth in existing services (expense and data management services and energy management services) and the recognition of a $2.3 million rebate in 2013 associated with achieving certain milestones on a five-year contract related to expense and data management services.

The increased revenues were partially offset by an increase in other operating expenses resulting from new services and increased costs associated with fulfilling higher volumes from existing services and an increase in depreciation and amortization expense.

Results of Operations - Other Businesses

2014 compared to 2013

The net income from these operations was $3.2 million for 2014 compared to a net loss of $4.7 million for 2013. The net income for 2014 was primarily the result of the settlement of the California power markets litigation, where Avista Energy received settlement proceeds and recognized an increase in pre-tax earnings of approximately $15.0 million. This was partially offset by a pre-tax contribution of $6.4 million of the proceeds to the Avista Foundation. See "Note 20 of the Notes to the Consolidated Financial Statements" for further information regarding this litigation settlement.

METALfx had net income of $0.9 million for 2014, compared to net income of $1.2 million for 2013.

We also incurred $2.4 million (net of tax) of corporate costs, including costs associated with exploring strategic opportunities.

2013 compared to 2012

The net loss from these operations was $4.7 million for 2013 compared to a net loss of $5.3 million for 2012. The net loss for 2013 was primarily the result of $2.1 million (net of tax) of corporate costs, including costs associated with exploring strategic opportunities and litigation costs incurred related to our previous operations at Avista Energy of $1.0 million (net of tax).

Additionally, during 2013 we incurred impairment losses of $2.2 million (net of tax) associated with our investment in an energy storage company and our investment in a fuel cell business. During 2012 we incurred impairment losses of $1.5 million (net of taxes) related to the impairment of our investment in a fuel cell business and the write-off of our investment in a solar energy company.

The losses above were partially offset by METALfx, which had net income of $1.2 million for each of 2013 and 2012.

Accounting Standards to be Adopted in 2015

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 2015. For information on accounting standards adopted in 2014 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 GAAP 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 and require the use of estimates and assumptions:

- ***Utility operating revenues***, which are generally recorded when service is rendered or energy is delivered to customers. Each month-end we estimate the amount of energy delivered to customers since the date of the last meter reading and a corresponding unbilled revenue amount is estimated and recorded. The critical estimates and assumptions in this calculation include a daily estimated allocation between billed and unbilled revenues for that day's energy usage based on our meter reading schedule and billing cycle day schedule, estimated adjustments due to variances in the meter reading schedule and estimates of electric line losses and natural gas system losses due to leakage. Changes to any one of these assumptions and estimates can result in material differences in the amount of unbilled revenue. See "Note 1 of the Notes to Consolidated Financial Statements" for further discussion of our utility operating revenue policy.

- ***Regulatory accounting***, which requires that certain costs and/or obligations 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 make the assumption that there are regulatory precedents for many of our regulatory items and that we will be allowed recovery of these costs via retail rates in future periods. If we were no longer allowed to apply regulatory accounting or no longer allowed recovery of these costs, we could be required to recognize significant write-offs of regulatory assets and liabilities in the Consolidated Statements of Income. See "Notes 1 and 22 of the Notes to Consolidated Financial Statements" for further discussion of our regulatory accounting policy.

- ***Utility energy commodity derivative asset and liability accounting***, where we estimate the fair value of outstanding commodity derivatives and we offset energy 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 delivery. This accounting treatment is supported by accounting orders issued by the UTC and IPUC. If we were no longer allowed to apply regulatory accounting or no longer allowed recovery of these costs, we could be required to recognize significant changes in fair value of these energy commodity derivatives on a regular basis in the Consolidated Statements of Income, which could lead to significant fluctuations in net income. See "Notes 1 and 6 of the Notes to Consolidated Financial Statements" for further discussion of our energy derivative accounting policy.

- ***Interest rate derivative asset and liability accounting,*** where we estimate the fair value of outstanding interest rate swaps, and U.S. Treasury lock agreements and offset the derivative asset or liability with a regulatory asset or liability. This is similar to the treatment of energy commodity derivatives described above. Upon settlement of 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 term of the associated debt. If we no longer applied regulatory accounting or were no longer allowed recovery of these costs, we could be required to recognize significant changes in fair value of these interest rate derivatives on a regular basis in the Consolidated Statements of Income, which could lead to significant fluctuations in net income.
- ***Pension Plans and Other Postretirement Benefit Plans***, discussed in further detail below.
- ***Goodwill***, discussed in further detail below.
- ***Contingencies,*** related to 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 potential 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. See "Notes 1 and 20 of the Notes to Consolidated Financial Statements" for further discussion of our commitments and contingencies.
- ***Discontinued operations,*** related to the accounting and financial statement presentation for Ecova following its disposition in 2014. In accordance with GAAP, this transaction caused Ecova to be accounted for as a discontinued operation. Ecova's revenues and expenses are included in the Consolidated Statements of Income in discontinued operations (as a single line item, net of tax). The gain, net of tax, recognized on the sale of Ecova is also included in discontinued operations. All tables throughout the Notes to Consolidated Financial Statements that present Consolidated Statements of Income information were revised to only include amounts from continuing operations. In addition, we are presenting earnings per share calculations for continuing and discontinued operations.

Pension Plans and Other Postretirement Benefit Plans - Avista Utilities

We have a defined benefit pension plan covering substantially all regular full-time employees at Avista Utilities that were hired prior to January 1, 2014. For substantially all regular non-union full-time employees at Avista Utilities that were hired on or after January 1, 2014, a defined contribution 401(k) plan replaced the defined benefit pension plan.

The 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 in debt securities and mutual funds, trusts and partnerships that hold marketable debt and equity securities, real estate and absolute return. 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 and also investment ranges for each asset class. The target investment allocation percentages are typically the midpoint of the established range and are 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 and others 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 $14.6 million for 2014, $28.8 million for 2013 and $28.1 million for 2012. Of our pension costs, approximately 60 percent are expensed and 40 percent are capitalized consistent with labor charges. The costs related to the SERP are expensed. Our costs for the pension plan are determined in part by actuarial formulas that are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension costs are affected by among other things:

- 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,
- assumed rate of increase in employee compensation,
- life expectancy of participants and other beneficiaries, and
- expected method of payment (lump sum or annuity) of pension benefits.

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 revised the key assumption of the discount rate in 2014, 2013 and 2012. Such changes had an effect on our pension costs and projected benefit obligation in 2014, 2013 and 2012 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 cash flows from interest and maturities similar to that of the expected payout of pension benefits. In 2014, we decreased the pension plan discount rate (exclusive of the SERP) to 4.21 percent from 5.1 percent in 2013. We used a discount rate of 4.15 percent in 2012. These changes in the discount rate increased the projected benefit obligation (exclusive of the SERP) by approximately $66.3 million in 2014 and decreased the obligation by $68.2 million in 2013.

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 6.60 percent in 2014, 6.60 percent in 2013 and 6.95 percent in 2012. This change increased pension costs by approximately $1.5 million in 2013. The actual return on plan assets, net of fees, was a gain of $56.0 million (or 11.6 percent) for 2014, a gain of $52.5 million (or 12.5 percent) for 2013 and a gain of $54.3 million (or 15.9 percent) for 2012. 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)%	$ — *	$ 2,434
Expected long-term return on plan assets	0.5 %	— *	(2,434)
Discount rate	(0.5)%	46,576	3,232
Discount rate	0.5 %	(41,377)	(2,997)

* 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, 2014 by $5.2 million and the service and interest cost by $0.4 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, 2014 by $4.1 million and the service and interest cost by $0.3 million.

For the estimated pension liability and pension costs as of December 31, 2014, we adopted the Society of Actuaries' mortality table that was published in 2014 as our base table, which reflects improved longevity of plan participants based on studies of wide populations through 2007 (RP-2014). We also adopted a modified form of the Society of Actuaries' MP-2014 mortality improvement scale, which projects improvements to life expectancies after the RP-2014 historic period that ended in 2007. For years subsequent to 2007, we reviewed data from other sources, including the Human Mortality Database, maintained by the University of California, Berkley and the Max Planck Institute for Demographic Research, and the Trustee's Report provided by the Social Security Administration. Based on data subsequent to 2007, the mortality improvement scale included in the MP-2014 for the three-year period immediately following its inception (2007) was shown to significantly overstate the actual mortality improvement for those years. As such, the mortality improvement scale we adopted assumes a lower rate of improved life expectancy than the MP-2014 scale as published. The updated mortality table resulted in an increase to the projected benefit obligation of $30.0 million.

Goodwill

We evaluate goodwill for impairment using a combination of a discounted cash flow model and a market approach 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 November 30 for AEL&P and our other businesses. As of December 31, 2014, we had goodwill of $52.7 million related to AEL&P and $5.2 million related to our other businesses.

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 unit's assets and liabilities and comparing the valuation to its carrying amounts, with the aggregate difference indicating the amount of impairment. In 2014, each reporting unit that was evaluated for impairment had a fair value that exceeded its book value, and no impairment losses were recorded.

Liquidity and Capital Resources

Overall Liquidity

Historically, Avista Corp.'s consolidated operating cash flows are primarily derived from the operations of Avista Utilities. The primary source of operating cash flows for Avista Utilities is revenues from sales of electricity and natural gas. Significant uses of cash flows from Avista Utilities 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.

During 2014, the sale of Ecova and the settlement of the California energy markets litigation at Avista Energy also provided significant cash flows.

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

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

We periodically file for rate adjustments for recovery of operating costs and capital investments and to seek the opportunity to earn reasonable returns as allowed by regulators. See further details in the section "Item 7: Management's Discussion and Analysis: Regulatory Matters."

For Avista Utilities, 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.

Avista Utilities 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.

In addition to the above, Avista Utilities enters into derivative instruments to hedge our exposure to certain risks, including fluctuations in commodity market prices, foreign exchange rates and interest rates (for purposes of issuing long-term debt in the future). These derivative instruments 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. See "Collateral Requirements" below.

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 Avista Corp.'s $400.0 million committed line of credit.

As of December 31, 2014, we had $262.4 million of available liquidity under the Avista Corp. committed line of credit. With our $400.0 million credit facility that expires in April 2019, we believe that we have adequate liquidity to meet our needs for the next 12 months.

Review of Consolidated Cash Flow Statement

Overall During 2014, cash flows from operating activities were $267.3 million, proceeds from the issuance of long-term debt were $150.0 million and we received $229.9 million from the sale of Ecova. Cash requirements included utility capital expenditures of $325.5 million, the net repayment of short-term borrowings of $66.0 million, the redemption of long-term debt of $40.0 million, defined benefit pension plan contributions of $32.0 million, dividends of $78.3 million and the repurchase of common stock of $79.9 million.

2014 compared to 2013

Consolidated Operating Activities

Net cash provided by operating activities was $267.3 million for 2014 compared to $242.6 million for 2013. Net cash used by the changes in certain current assets and liabilities components was $50.0 million for 2014, compared to net cash used of $48.2 million for 2013. The net cash used during 2014 primarily reflects cash outflows from changes in accounts payable, natural gas stored and income taxes receivable. These were partially offset by cash inflows from changes in other current liabilities (primarily related to accrued taxes and interest) and accounts receivable.

The net cash used during 2013 primarily reflects cash outflows from changes in accounts receivable, accounts payable and other current assets (primarily related to miscellaneous current assets and income taxes receivable). These were partially offset by cash inflows from other current liabilities (primarily related to accrued taxes and interest).

The gross gain on the sale of Ecova of $160.6 million for 2014 is deducted in reconciling net income to net cash provided by operating activities. The cash proceeds from the sale (which includes the gross gain) is included in investing activities

Net amortizations of power and natural gas costs were $14.8 million for 2014 compared to $9.4 million for 2013.

The provision for deferred income taxes was $144.3 million for 2014 compared to $23.5 million for 2013. The increase for 2014 was primarily due to the combination of implementation by the Company of updated federal tax tangible property regulations and increased deductions related to bonus depreciation.

Contributions to our defined benefit pension plan were $32.0 million for 2014 compared to $44.3 million in 2013.

Collateral posted for derivative instruments increased by $23.3 million in 2014 compared to an increase of $16.1 million in 2013. We had cash collateral posted of $49.4 million as of December 31, 2014 and $26.1 million as of December 31, 2013.

Net cash paid for income taxes was $45.4 million for 2014 compared to $44.8 million for 2013.

Cash paid for interest was $73.5 million for 2014 compared to $75.4 million for 2013.

Consolidated Investing Activities

Net cash used in investing activities was $103.7 million for 2014, a decrease compared to $312.2 million for 2013. During 2014, we received cash proceeds (net of cash sold and escrow amounts) of $229.9 million related to the sale of Ecova. A portion of the proceeds from the Ecova sale was used to pay off the balance of Ecova's long-term borrowings and make payments to option holders and noncontrolling interests (included in financing activities). We also used a portion of these proceeds to pay our $74.8 million tax liability associated with the gain on sale. Utility property capital expenditures increased by $31.2 million for 2014 as compared to 2013. A significant portion of Ecova's funds held for clients were held as securities available for sale with purchases of $12.3 million and sales and maturities of $14.6 million in 2014. For 2013, Ecova had purchases of $35.9 million and sales and maturities of $23.0 million. The fluctuation in the balance of funds held for customers resulted in a decrease to cash of $18.9 million for 2014 as compared to an increase to cash of $1.8 million for 2013. We received $15.0 million in cash (net of cash paid) related to the acquisition of AERC during 2014.

Consolidated Financing Activities

Net cash used in financing activities was $224.0 million for 2014 compared to net cash provided of $76.8 million for 2013. During 2014, short-term borrowings on Avista Corp.'s committed line of credit decreased $66.0 million. Net borrowings on Ecova's committed line of credit decreased $46.0 million during the period with $6.0 million in payments throughout the year and $40.0 million related to the close of the Ecova sale. In September 2014, AEL&P issued $75.0 million of first mortgage bonds. In December 2014, Avista Corp. issued $60.0 million of first mortgage bonds and AERC issued a $15.0 million unsecured note representing a term loan. We cash settled interest rate swaps in conjunction with the pricing of the $60.0 million of Avista Corp. first mortgage bonds and received $5.4 million. The majority of the $40.0 million of retirements of long-term debt in 2014 relates to AEL&P paying off its existing debt.

In connection with the closing of the Ecova sale, we made cash payments of $54.2 million to noncontrolling interests and $20.9 million to stock option holders and redeemable noncontrolling interests of Ecova.

Cash dividends paid increased to $78.3 million (or $1.27 per share) for 2014 from $73.3 million (or $1.22 per share) for 2013. Excluding issuances related to the acquisition of AERC, we issued $4.1 million of common stock during 2014. We issued $150.1 million of common stock to AERC shareholders, and this is reflected as a non-cash financing activity. The fluctuation in the balance of customer fund obligations at Ecova increased cash by $16.2 million. During 2014, we repurchased $79.9 million of common stock.

Cash inflows during 2013 were from a $119.0 million increase in short-term borrowings on Avista Corp.'s committed line of credit, the issuance of $90.0 million of long-term debt and the issuance of $4.6 million of common stock. We also cash settled interest rate swap agreements for $2.9 million related to the pricing of the $90.0 million of long-term debt. Cash outflows during 2013 were from the maturity of long-term debt of $50.5 million and a net decrease in borrowings on Ecova's committed line of credit of $8.0 million (borrowings of $3.0 million and repayments of $11.0 million).

2013 compared to 2012

Consolidated Operating Activities

Net cash provided by operating activities was $242.6 million for 2013 compared to $316.6 million for 2012. Net cash used by changes in certain current assets and liabilities components was $48.2 million for 2013, compared to net cash provided of $63.6 million for 2012. The net cash used during 2013 primarily reflects net cash outflows from accounts receivable, accounts payable and income taxes receivable. These were partially offset by cash inflows from changes in other current liabilities (primarily related to accrued taxes and interest).

The net cash provided during 2012 primarily reflects positive cash flows from other current assets (primarily related to a decrease in deposits with counterparties), income taxes receivable and net cash inflows related to accounts payable.

Net deferrals of power and natural gas costs were $9.4 million for 2013 compared to net amortizations of $6.7 million for 2012. The provision for deferred income taxes was $23.5 million for 2013 compared to $21.4 million for 2012. Contributions to our defined benefit pension plan were $44.3 million for 2013 compared to $44.0 million in 2012. Cash paid for interest was $75.4 million for 2013, compared to $74.9 million for 2012.

Consolidated Investing Activities

Net cash used in investing activities was $312.2 million for 2013, an increase compared to $294.7 million for 2012. Utility property capital expenditures increased by $23.2 million for 2013 compared to 2012. A significant portion of Ecova's funds held for clients are held as securities available for sale with purchases of $35.9 million and sales and maturities of $23.0 million in 2013. For 2012, Ecova had purchases of $100.4 million and sales and maturities of $138.0 million. In 2012, Ecova paid $50.3 million for the acquisition of LPB.

Consolidated Financing Activities

Net cash provided by financing activities was $76.8 million for 2013 compared to net cash used of $21.1 million for 2012. Cash inflows during 2013 were from a $119.0 million increase in short-term borrowings on Avista Corp.'s committed line of credit, the issuance of $90.0 million of long-term debt and the issuance of $4.6 million of common stock. We also cash settled interest rate swap agreements for $2.9 million related to the pricing of the $90.0 million of long-term debt. Cash outflows during 2013 were from the maturity of long-term debt of $50.5 million and a net decrease in borrowings on Ecova's committed line of credit of $8.0 million (borrowings of $3.0 million and repayments of $11.0 million). Cash dividends paid increased to $73.3 million (or $1.22 per share) for 2013 from $68.6 million (or $1.16 per share) for 2012.

During 2012, short-term borrowings on Avista Corp.'s committed line of credit decreased $9.0 million. Net borrowings on Ecova's committed line of credit increased $19.0 million and these proceeds were used to fund the acquisition of LPB. 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.

Collateral Requirements

Avista Utilities' 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, 2014, we had cash deposited as collateral of $20.6 million and letters of credit of $14.5 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, 2014, we would potentially be required to post additional collateral of up to $11.9 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 also 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 $26.1 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. As of December 31, 2014, we had interest rate swap agreements outstanding with a notional amount totaling $420.0 million and we had deposited cash in the amount of $28.9 million and letters of credit of $10.9 million as collateral for these interest rate swap derivative contracts. If our credit ratings were lowered to below “investment grade” based on our interest rate swap agreements outstanding at December 31, 2014, we would have to post $19.4 million of additional collateral.

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, 2014 and 2013 (dollars in thousands):

	December 31, 2014		December 31, 2013	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 6,424	0.2%	$ 358	—%
Current portion of nonrecourse long-term debt (Spokane Energy)	1,431	0.1%	16,407	0.6%
Short-term borrowings	105,000	3.4%	171,000	6.0%
Long-term borrowings under committed line of credit	—	—%	46,000	1.6%
Long-term debt to affiliated trusts	51,547	1.6%	51,547	1.8%
Nonrecourse long-term debt (Spokane Energy)	—	—%	1,431	0.1%
Long-term debt	1,492,062	47.5%	1,272,425	44.5%
Total debt	1,656,464	52.8%	1,559,168	54.6%
Total Avista Corporation shareholders' equity	1,483,671	47.2%	1,298,266	45.4%
Total	$ 3,140,135	100.0%	$ 2,857,434	100.0%

Our shareholders' equity increased $185.4 million during 2014 primarily due to net income, which included the net gain on the sale of Ecova, and the issuance of common stock to AERC shareholders, partially offset by the repurchase of common stock and dividends.

Our long-term debt increased $219.6 million during 2014 due to the issuance of debt at Avista Corp., AEL&P and AERC and also because of the Snettisham capital lease obligation that was acquired with the acquisition of AERC. See "Note 14 of the Notes to Consolidated Financial Statements" for further information regarding the debt issuances and the Snettisham capital lease obligation.

The Snettisham capital lease obligation is treated differently for regulatory purposes than other long-term debt. All debt service obligations (principal and interest) related to this power purchase agreement are paid on a regular basis and are included in utility resource costs and included in AEL&P's retail revenue requirements, whereas the principal of other long-term debt is typically paid in a lump sum at maturity.

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.

See "Item 7: Management's Discussion and Analysis, Executive Level Summary" for a detailed discussion of the liquidity and capital resource transactions which occurred during 2014 and our anticipated needs for 2015.

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):

	2014	2013	2012
Balance outstanding at end of year	$ 105,000	$ 171,000	$ 52,000
Letters of credit outstanding at end of year	$ 32,579	$ 27,434	$ 35,885
Maximum balance outstanding during the year	$ 171,000	$ 171,000	$ 92,500
Average balance outstanding during the year	$ 62,088	$ 27,580	$ 23,921
Average interest rate during the year	1.01%	1.14%	1.18%
Average interest rate at end of year	0.93%	1.02%	1.12%

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, 2014, 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.

We are restricted under our Restated Articles of Incorporation, as amended, as to the additional preferred stock we can issue. As of December 31, 2014, we could issue $2.2 billion of additional preferred stock at an assumed dividend rate of 5.8 percent. We are not planning to issue preferred stock.

Under the Avista Corp. and the AEL&P Mortgages and Deeds of Trust securing Avista Corp.'s and AEL&P's first mortgage bonds (including Secured Medium-Term Notes), respectively, each entity 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 at each entity which have not previously been made the basis of any application under the Mortgages, or
- an equal principal amount of retired first mortgage bonds at each entity which have not previously been made the basis of any application under the Mortgages, or
- deposit of cash.

However, Avista Corp. and AEL&P may not individually issue any additional first mortgage bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the particular entity issuing the bonds has "net earnings" (as defined in the Mortgages) for any period of 12 consecutive calendar months out of the preceding 18 calendar months that 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, 2014, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.0 billion in aggregate principal amount of additional first mortgage bonds at Avista Corp. and $3.5 million at AEL&P. We believe that we have adequate capacity to issue first mortgage bonds to meet our financing needs over the next several years.

Capital Expenditures

Utility cash-basis capital expenditures were $891.1 million for the years 2012 through 2014 including $1.6 million at AEL&P for 2014. We expect Avista Utilities' capital expenditures to be about $375 million for 2015 and $350 million for each of 2016 and 2017. Most of the capital expenditures at Avista Utilities 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. Our capital budget at Avista Utilities for 2015 includes the following (dollars in millions):

Transmission and distribution (upgrade current facilities)	$	121
Information technology		54
Customer growth (incremental transmission and distribution)		39
Generation		53
Natural gas		47
Facilities		25
Environmental		22
Other		14
Total	$	375

Avista Utilities' estimated capital expenditures for the next few years include several significant capital investments we are expecting to make, including:

- the ongoing and multi-year redevelopment of the Little Falls hydroelectric plant on the Spokane River,
- the continuing rehabilitation of the Nine Mile hydroelectric plant on the Spokane River,
- information technology upgrades that include the replacement of our customer information and work management systems (which were implemented in February 2015),
- the ongoing project to systematically replace portions of Aldyl-A natural gas distribution pipe, and
- technology investments for deploying Advanced Metering Infrastructure in Washington, including installation of advanced meters, beginning in 2016.

At AEL&P, we expect to spend approximately $15 million for each of 2015 and 2016. A significant portion of these capital expenditures are for the construction of an additional back-up generation plant.

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.”

Off-Balance Sheet Arrangements

As of December 31, 2014, we had $32.6 million in letters of credit outstanding under our $400.0 million committed line of credit, compared to $27.4 million as of December 31, 2013.

Pension Plan

We contributed $32.0 million to the pension plan in 2014. We expect to contribute a total of $60.0 million to the pension plan in the period 2015 through 2019, with an annual contribution of $12.0 million over that period.

The final determination of pension plan contributions for future periods is subject to multiple variables, most of which are beyond our control, including 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 variables, including those listed above.

See "Note 10 of the Notes to Consolidated Financial Statements" for additional information regarding the pension plan.

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 25, 2015:

	Standard & Poor’s (1)	Moody’s (2)
Corporate/Issuer rating	BBB	Baa1
Senior secured debt	A-	A2
Senior unsecured debt	BBB	Baa1

(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

On February 6, 2015, Avista Corp.’s Board of Directors declared a quarterly dividend of $0.33 per share on the Company’s common stock. This was an increase of $0.0125 per share, or 4 percent from the previous quarterly dividend of $0.3175 per share.

See "Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" for a detailed discussion of our dividend policy and the factors which could limit the payment of dividends.

Contractual Obligations

The following table provides a summary of our future contractual obligations as of December 31, 2014 (dollars in millions):

	2015	2016	2017	2018	2019	Thereafter
Avista Utilities:						
Long-term debt maturities	$ —	$ 90	$ —	$ 273	$ 90	$ 901
Long-term debt to affiliated trusts	—	—	—	—	—	52
Interest payments on long-term debt (1)	70	69	69	59	52	634
Short-term borrowings	105	—	—	—	—	—
Energy purchase contracts (2)	360	266	202	186	175	1,317
Operating lease obligations (3)	1	—	—	—	—	3
Other obligations (4)	29	36	28	26	29	194
Information technology contracts (5)	24	9	9	—	—	—
Pension plan funding (6)	12	12	12	12	12	—
AERC (consolidated):						
Long-term debt maturities	—	—	—	—	15	75
Interest payments on long-term debt (1)	4	4	4	4	4	84
Capital lease obligations (3)	6	6	6	6	6	83
Capital funding for hydro project (7)	2	2	2	2	2	41
Other obligations (4)	2	2	2	2	3	45
Pension plan and other postretirement funding (6)	1	1	1	1	1	—
Spokane Energy:						
Nonrecourse long-term debt maturities	1	—	—	—	—	—
Avista Capital (consolidated):						
Operating lease obligations (3)	1	1	1	1	1	1
Investment funding (8)	1	1	1	—	—	—
Total contractual obligations	$ 619	$ 499	$ 337	$ 572	$ 390	$ 3,430

(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, 2014.

(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.

(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) 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 were completed in February 2015.

(6) Represents our estimated cash contributions to pension plans and other postretirement benefit plans through 2019. We cannot reasonably estimate pension plan contributions beyond 2019 at this time and have excluded them from the table above.

(7) Represents the contractually required capital project funding associated with the Snettisham hydroelectric project. These costs are generally recovered through base retail rates.

(8) Represents a commitment to fund a limited liability company in exchange for equity ownership, made by a subsidiary of Avista Capital.

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 $3.0 million remaining asset retirement obligations as of December 31, 2014.

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 generally 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 energy technologies, including solar, wind or geothermal generation, may also compete with us for sales to existing customers. While the risk is currently small in our service territory given the small numbers of customers utilizing these technologies, advances in power generation, energy efficiency and other alternative energy technologies could lead to more wide-spread usage of these technologies, thereby reducing customer demand for the energy supplied by us. This reduction in usage and demand would reduce our revenue and negatively impact our financial condition including possibly leading to our inability to fully recover our investments in generation, transmission and distribution assets. Similarly, our natural gas distribution operations compete with other energy sources including heating oil, propane and other fuels.

Certain natural gas customers could bypass our natural gas system, reducing both revenues and recovery of fixed costs. To reduce the potential for such bypass, 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 bypassing 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.

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 statistical areas in our Avista Utilities 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 2014 showed positive job growth, and lower unemployment rates in all three metropolitan areas. However, the unemployment rates in Spokane and Medford are still above the national average. Foreclosure rates are in line with or below the U.S rate in all three area, and key leading indicators, initial unemployment claims and residential building permits, continue to signal modest growth over the next 12 months. Therefore, in 2015, 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 2013 and December 2014. In Spokane, Washington employment growth was 2.1 percent with gains in financial activities; professional and business services; education and health services; and leisure and hospitality. Employment increased by 3.0 percent in Coeur d'Alene, Idaho, reflecting gains in construction; manufacturing; professional and business services; leisure and hospitality; and other services. In Medford, Oregon, employment growth was 0.9 percent, with gains in manufacturing; education and health services; and government. U.S. nonfarm sector jobs grew by 2.1 percent in the same 12-month period.

Seasonally adjusted unemployment rates went down in December 2014 from the year earlier in Spokane, Coeur d'Alene, and Medford. In Spokane the rate was 7.4 percent in December 2013 and declined to 7.2 percent in December 2014; in Coeur d'Alene the rate went from 6.6 percent to 4.3 percent; and in Medford the rate declined from 9.1 percent to 8.4 percent. The U.S. rate declined from 6.7 percent to 5.6 percent in the same period.

The housing market in our Avista Utilities service area continues to experience foreclosure rates in line with or lower than the national average. The December 2014 national rate was 0.09 percent, compared to 0.08 percent in Spokane County, Washington; 0.04 percent in Kootenai County (Coeur d'Alene), Idaho; and 0.1 percent in Jackson County (Medford), Oregon.

Our AEL&P service area is centered in Juneau. Although Juneau is Alaska’s state capital, it is not a metropolitan statistical area. This means breadth and frequency of economic data is more limited. Therefore, the dates of Juneau's economic data may significantly lag the period of this filing.

The Quarterly Census of Employment and Wages for Juneau shows employment declined 1.3 percent between second quarter 2013 and second quarter 2014. A significant portion of this decline was due to a contraction in government employment, which is Juneau's largest single sector. Government (including active duty military personnel) accounts for approximately 37 percent of total employment. Employment declines also occurred in manufacturing; trade, transportation, and utilities; financial activities; and education and health services. Employment gains did occur in construction; information; professional and business services; and leisure and hospitality. Between December 2013 and December 2014 the non-seasonally adjusted unemployment rate increased from 4.6 percent to 4.8 percent.

The Juneau foreclosure rate is below the U.S. rate. The December 2014 rate was 0.03 percent compared to 0.09 percent for the U.S.

Based on our forecast for 2015 through 2018 for Avista Utilities' service area, we expect annual electric customer growth to average 1.2 percent, within a forecast range of 0.8 percent to 1.6 percent. We expect annual natural gas customer growth to average 1.0 percent, within a forecast range of 0.5 percent to 1.5 percent. We anticipate retail electric load growth to average 0.8 percent, within a forecast range of 0.5 percent and 1.1 percent. We expect natural gas load growth to average 1.3 percent, within a forecast range of 0.8 percent and 1.8 percent. The forecast ranges reflect (1) the inherent uncertainty associated with the economic assumptions on which forecasts are based and (2) natural gas customer and load growth has been historically more volatile.

In AEL&P's service area, we expect annual residential customer growth to be in a narrow range around 0.4 percent for 2015 through 2018. We expect no significant growth in commercial and government customers over the same period. We anticipate that average annual total load growth will be in a narrow range around 0.9 percent, with residential load growth averaging about 0.6 percent; commercial about 1.2 percent; and government about 1.0 percent.

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,

- an assumption that we will incur no material loss of retail customers due to self-generation or retail wheeling, and
- an assumption that demand for electricity and natural gas as a fuel for mobility will for now be immaterial.

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 (expires in 2017), Coyote Springs 2 (expires in 2018), the Kettle Falls GS (renewal expected in 2015), and the Rathdrum 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 newly applicable CAA requirements. We actively monitor legislative, regulatory and program developments within the CAA that may impact our facilities.

On March 6, 2013, the Sierra Club and Montana Environmental Information Center, filed a Complaint (Complaint) in the United States District Court for the District of Montana, Billings Division, against the owners of the Colstrip. The Complaint alleges certain violations of the CAA. See “Sierra Club and Montana Environmental Information Center Complaint Against the Owners of Colstrip” in “Note 20 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 utilizes Particulate Matter as a surrogate for air toxics (including metals and acid gases), the Colstrip owners have reviewed recent stack testing data and expect that no additional emission control systems will be needed for Units 3 & 4 MATS compliance. However, Units 1 & 2 (which we do not have ownership interest in) will require a pollution control enhancement for MATS compliance which has resulted in a request of an extension to the compliance deadline. The new MATS compliance deadline for Colstrip in now April, 16, 2016. We will continue to monitor future testing results but currently we do not believe there will be any material effect on Colstrip Units 3 & 4.

Regional Haze Program

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

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 effects, 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 (GHG) 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 GHG emissions from new motor vehicles; subsequently, the EPA issued regulations on tailpipe emissions of 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, both of which apply to power plants and other commercial and industrial facilities. In June 2013, President Obama released his Climate Action Plan which reiterates the goal of reducing GHG emissions in the U.S. "in the range of" 17 percent below 2005 levels by 2020 through such actions as regulating power plant emissions, promoting increased use of renewables and clean energy technology and establishing tighter energy efficiency standards. In keeping with a Presidential Memorandum also issued in June 2013, the EPA issued a new proposal to limit carbon dioxide emissions from new and modified coal-fired and natural gas-fueled electrical generating units in late 2013. The EPA also announced its intention to issue GHG guidelines for existing sources.

The rule for *new* sources has not been finalized, and the proposed rule for *existing* sources was released on June 2, 2014. The existing source proposal aims to reduce GHG emissions from covered existing generation sources by 30 percent nationally by 2030 from a 2005 baseline. The proposal establishes individual state emission reduction goals based upon assumptions upon the potential for (1) heat rate improvements at coal-fired units, (2) increased utilization of natural gas-fired combined cycle plants up to a 70 percent capacity factor, (3) utilize more low or zero carbon emitting generation resources, and (4) increase demand side efficiency by 1.5 percent per year. States can rely on these four elements, or "building blocks," as policy mechanisms to meet their respective goals, or they could adopt market mechanisms as an alternative, subject to the EPA's approval. The EPA is expected to finalize both rules in the summer of 2015. The states are scheduled to submit compliance plans regarding the existing source rule to the EPA by June 2016, with a potential for an extension until June 2017, or June 2018 if the state will be part of a regional approach.

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 (including natural gas fired 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 as well as the final permit limitations. Additionally, the Climate Action Plan requirements related to preparing the U.S. for the impacts of climate change could affect us and others in the industry as transmission system modifications to improve resiliency may be needed in order to meet those requirements. The promulgated and proposed GHG rulemakings mentioned above also have been legally challenged in multiple venues, so we cannot fully predict the outcome or estimate the extent to which our facilities may be impacted by these regulations at this time. We intend to seek recovery of any costs related to compliance with these requirements through the ratemaking process.

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.

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 the EPA's regulation of GHG emissions. We will continue to monitor actions by the Department as it may proceed to adopt additional regulations under its CAA authorities, and cannot estimate 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 estimate any material impact at this time.

The Energy Independence Act (EIA), in Washington 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 EIA's mandates were required to 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 EIA through a variety of renewable energy generating means, including, but not limited to, some combination of hydro upgrades, wind and biomass. In 2012, EIA was amended in such a way that our Kettle Falls GS 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.

On April 29, 2014, Washington State Governor Jay Inslee issued Executive Order 14-04, “Washington Carbon Pollution Reduction and Clean Energy Action.” The order created a “Climate Emissions Reduction Task Force” to provide recommendations to the Governor on design and implementation of a market-based carbon pollution program to inform possible legislative proposals in 2015. The order also called on the program to “establish a cap on carbon pollution emissions, with binding requirements to meet our statutory emission limits.” The order also states that the Governor’s Legislative Affairs and Policy Office “will seek negotiated agreements with key utilities and others to reduce and eliminate over time the use of electrical power produced from coal.” The Task Force issued a report summarizing its efforts, which included a range of potential carbon-reducing proposals. Subsequently, in January 2015, at Washington Governor Jay Inslee’s request, the Carbon Pollution Accountability Act was introduced as a bill in the Washington legislature. The bill includes a proposed cap and trade system for carbon emissions from a wide range of sources, including fossil-fired electrical generation, “imported” power generated by fossil fuels, natural gas sales and use, and certain uses of biomass for electrical generation. While we cannot predict the outcome of actions arising out of proposed legislation at this time or estimate the effect thereof, we will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to our generation assets.

On February 6, 2014, the UTC issued a letter finding that Puget Sound Energy’s (PSE’s) 2013 Electric Integrated Resource Plan meets the requirements of the Revised Code of Washington and the Washington Administrative Code. In its letter, however, the UTC expressed concern regarding the continued operation of the Colstrip plant as a resource to serve retail customers. Although the UTC recognized that the results of the analyses presented by PSE “differed significantly between [Colstrip] Units 1 and 2 and Units 3 and 4,” the UTC did not limit its concerns solely to Colstrip Units 1 and 2. The UTC recommended that PSE “consult with UTC staff to consider a Colstrip Proceeding to determine the prudency of any new investment in Colstrip before it is made or, in the alternative, a closure or partial-closure plan.” As a 15 percent owner of Colstrip Units 3 and 4, we cannot estimate the effect of such proceeding, should it occur, on the future ownership and operation of our share of Colstrip Units 3 and 4. Our remaining investment in Colstrip Units 3 and 4 as of December 31, 2014 was $110.7 million.

In 2013, the Oregon Legislature enacted Senate Bill 306, directing the Legislative Revenue Office to examine the feasibility of imposing a carbon tax on a statewide basis. A report prepared by Portland State University’s Northwest Economic Research Center was submitted to the Legislature in December 2014 and it analyzed, broadly, potential economic impacts of enacting a carbon tax. Any future proposal to tax natural gas as a fuel for electricity generation and to tax the carbon content of electricity produced in, but exported from, Oregon could have implications for the cost of operating Coyote Springs II. We will monitor further developments from the study, but we cannot estimate any actual material impact at this time.

Coal Ash Management/Disposal

On December 19, 2014, the EPA issued a final rule regarding coal combustion residuals (CCRs), also termed coal combustion byproducts or coal ash. Colstrip, of which Avista Corp. is a minority owner, produces this byproduct. The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act (RCRA), the nation's primary law for regulating solid waste. The final rule has not yet been published in the Federal Register. We continue to review the potential costs of complying with the new CCR standards. We cannot currently estimate the operational or financial impact of CCR regulation, but we believe this rule will have an impact on Colstrip. If we were to incur incremental costs as a result of these regulations, we would seek recovery in customer rates. We do not expect these rules to have a material impact to the operations of Colstrip.

Threatened and Endangered Species and Wildlife

A number of species of fish in the Northwest are listed as threatened or endangered under the Federal Endangered Species Act. Efforts to protect these and other species have not directly impacted generation levels at any of our hydroelectric facilities. We are implementing fish protection measures at our hydroelectric project on the Clark Fork River under a 45-year FERC operating license for Cabinet Gorge and Noxon Rapids (issued March 2001) that incorporates a comprehensive settlement agreement. The restoration of native salmonid fish, including bull trout, is a key part of the agreement. The result is a collaborative native salmonid restoration program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana on the lower Clark Fork River, consistent with requirements of the FERC license. The U.S. Fish & Wildlife Service issued an updated Critical Habitat Designation for bull trout in 2010 that includes the lower Clark Fork River, as well as portions of the Coeur d'Alene basin within our Spokane River Project area, and is currently developing a final Bull Trout Recovery Plan under the ESA. Issues related to these activities are expected to be resolved through the ongoing collaborative effort of our Clark Fork and Spokane River FERC licenses. See “Spokane River Licensing” and “Fish Passage at Cabinet Gorge and Noxon Rapids” in “Note 20 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.

Kettle Falls Generation Station - Diesel Spill Investigation and Remediation

In December 2013, our operations staff at the Kettle Falls Generation Station discovered that approximately 10,000 gallons of diesel fuel had leaked underground from the piping system used to fuel heavy equipment. We made all proper agency notifications and worked closely with the Washington State Department of Ecology during the spill response and investigation phase. We installed ground water monitoring wells, and there is no indication that ground or surface water is threatened by the spill. We initiated a voluntary cleanup action with the installation of a recovery system which is now fully operational. See "Note 20 of the Notes to Consolidated Financial Statements" for further discussion of this issue.

Other

For other environmental issues and other contingencies see “Note 20 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 positions 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 natural 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.

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 new 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,
- the number of market participants and the willingness of market participants to trade, and
- weather conditions (temperatures, precipitation levels and wind patterns) which affect energy demand, including weather-sensitive customer demand, and electric generation.

Any combination of these factors that reduce 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, 2014 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 (1)	Financial (1)	Physical (1)	Financial (1)
2015	$ (6,053)	$ (27,664)	$ (10,607)	$ (50,852)	$ 17	$ 32,629	$ 1,228	$ 31,661
2016	(5,978)	(5,124)	(2,970)	(19,381)	(80)	13,126	(853)	10,170
2017	(4,657)	—	(355)	(2,428)	(117)	1,151	—	119
2018	(4,173)	—	—	(389)	(120)	—	—	—
2019	(2,191)	—	—	(147)	(85)	—	—	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2013 that are expected to settle in each respective year (dollars in thousands):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
2014	$ (215)	$ 7,243	$ (6,131)	$ (2,663)	$ (221)	$ (6,226)	$ (1,214)	$ (1,404)
2015	(2,818)	(1,798)	(2,450)	(9,586)	(34)	3,121	—	4,298
2016	(3,289)	—	(1,171)	(7,400)	(83)	3,529	—	2,230
2017	(2,955)	—	(86)	—	(187)	—	—	—
2018	(2,661)	—	—	—	(313)	—	—	—
Thereafter	(1,456)	—	—	—	(148)	—	—	—

(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 are delivered 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. In addition, the Environmental and Operations Committee of the Company's Board of Directors has the role of overseeing risks associated with the Company's legal and regulatory compliance in its operations including environmental compliance, energy resources, transmission and distribution operations, employee safety performance, and corporate security, including technology risks. Our Risk Management and Environmental and Operations Committees review 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. Our Risk Management Committee also reviews our interest risk management plan. 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.

Even though we work to manage our exposure to interest rate risk by locking in certain long-term interest rates through interest rate swap agreements, if market interest rates decrease below the interest rates we have locked in, this will result in a liability related to our interest rate swap agreements, which can be significant. However, through our regulatory accounting practices similar to our energy commodity derivatives, any interim mark-to-market gains or losses are offset by regulatory assets and liabilities. Upon settlement of 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 term of the associated debt.

The following table summarizes our interest rate swap agreements outstanding as of December 31, 2014 and December 31, 2013 (dollars in thousands):

	December 31, 2014	December 31, 2013
Number of agreements	22	11
Notional amount	$ 420,000	$ 245,000
Mandatory cash settlement dates	2015 to 2018	2014 to 2018
Short-term derivative assets (1)	$ 460	$ 13,968
Long-term derivative assets (1)	—	19,575
Short-term derivative liability (1)	(7,325)	—
Long-term derivative liability (1) (2)	(40,857)	—

(1) There are offsetting regulatory assets and liabilities for these items on the Consolidated Balance Sheets in accordance with regulatory accounting practices.
(2) The balance as of December 31, 2014 reflects the offsetting of $28.9 million of cash collateral against the net derivative positions where a legal right of offset exists.

In anticipation of issuing long-term debt in future years, we entered into four interest rate swap agreements in January 2015, with a total aggregate notional amount of $80.0 million and mandatory cash settlement dates in 2016, 2018 and 2019.

The following table shows our outstanding interest rate swaps after consideration of the swaps entered into subsequent to December 31, 2014 (dollars in thousands):

As of Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
February 25, 2015	5	$ 75,000	2015
	6	115,000	2016
	3	45,000	2017
	11	245,000	2018
	1	20,000	2019

We estimate that a 10-basis-point increase in forward LIBOR interest rates as of December 31, 2014 would decrease the interest rate swap derivative net liability by $9.0 million, while a 10-basis-point decrease would increase the interest rate swap net liability by $9.3 million.

We estimated that a 10-basis-point increase in forward LIBOR interest rates as of December 31, 2013 would have increased 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 $3.4 million.

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

Historically, during years where we have long-term debt that is maturing, we have to issue long-term debt to replace the maturing debt. To hedge our interest rate risk associated with these expected long-term debt issuances, we enter into interest rate swap agreements (discussed above). 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, 2014 (dollars in thousands):

	2015	2016	2017	2018	2019	Thereafter	Total	Fair Value
Fixed rate long-term debt	$ —	$ 90,000	$ —	$ 272,500	$ 105,000	$ 975,500	$ 1,443,000	$ 1,646,635
Weighted average interest rate	—	0.84%	—	6.07%	5.22%	5.16%	5.07%	
Fixed rate nonrecourse long-term debt of Spokane Energy	$ 1,431	—	—	—	—	—	$ 1,431	$ 1,440
Weighted average interest rate	8.45%	—	—	—	—	—	8.45%	
Variable rate long-term debt to affiliated trusts	—	—	—	—	—	$ 51,547	$ 51,547	$ 38,582
Weighted average interest rate	—	—	—	—	—	1.11%	1.11%	

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.

The following table summarizes the foreign currency hedges that we have entered into as of December 31 (dollars in thousands):

	2014	2013
Number of contracts	18	23
Notional amount (in United States dollars)	$ 5,474	$ 8,631
Notional amount (in Canadian dollars)	6,198	9,191
Other current derivative asset (liability)	(20)	1

Further information for derivatives and fair values is disclosed at “Note 6 of the Notes to Consolidated Financial Statements” and “Note 16 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 Shareholders of
Avista Corporation
Spokane, Washington

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the “Company”) as of December 31, 2014 and 2013, 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, 2014. 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, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report, dated February 25, 2015 expressed an unqualified opinion on the Company’s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 25, 2015

CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

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

	2014	2013	2012
Operating Revenues:			
Utility revenues	$ 1,433,343	$ 1,402,195	$ 1,352,385
Non-utility revenues	39,219	39,549	38,953
Total operating revenues	1,472,562	1,441,744	1,391,338
Operating Expenses:			
Utility operating expenses:			
Resource costs	678,244	689,586	693,127
Other operating expenses	286,832	276,228	276,780
Depreciation and amortization	129,570	117,174	112,091
Taxes other than income taxes	94,300	88,435	83,409
Non-utility operating expenses:			
Other operating expenses	30,418	38,651	38,041
Depreciation and amortization	610	581	792
Total operating expenses	1,219,974	1,210,655	1,204,240
Income from continuing operations	252,588	231,089	187,098
Interest expense	75,302	77,118	75,104
Interest expense to affiliated trusts	450	467	541
Capitalized interest	(3,924)	(3,676)	(2,401)
Other income-net	(11,346)	(5,167)	(2,713)
Income from continuing operations before income taxes	192,106	162,347	116,567
Income tax expense	72,240	58,014	39,764
Net income from continuing operations	119,866	104,333	76,803
Net income from discontinued operations (Note 5)	72,411	7,961	1,997
Net income	192,277	112,294	78,800
Net income attributable to noncontrolling interests	(236)	(1,217)	(590)
Net income attributable to Avista Corporation shareholders	$ 192,041	$ 111,077	$ 78,210

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF INCOME (continued)

Avista Corporation

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

	2014	2013	2012
Amounts attributable to Avista Corp. shareholders:			
Net income from continuing operations attributable to Avista Corp. shareholders	$ 119,817	$ 104,273	$ 76,719
Net income from discontinued operations attributable to Avista Corp. shareholders	72,224	6,804	1,491
Net income attributable to Avista Corp. shareholders	$ 192,041	$ 111,077	$ 78,210
Weighted-average common shares outstanding (thousands), basic	61,632	59,960	59,028
Weighted-average common shares outstanding (thousands), diluted	61,887	59,997	59,201
Earnings per common share attributable to Avista Corp. shareholders, basic:			
Earnings per common share from continuing operations	$ 1.94	$ 1.74	$ 1.30
Earnings per common share from discontinued operations	1.18	0.11	0.02
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 3.12	$ 1.85	$ 1.32
Earnings per common share attributable to Avista Corp. shareholders, diluted:			
Earnings per common share from continuing operations	$ 1.93	$ 1.74	$ 1.30
Earnings per common share from discontinued operations	1.17	0.11	0.02
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 3.10	$ 1.85	$ 1.32

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

	2014	2013	2012
Net income	$ 192,277	$ 112,294	$ 78,800
Other Comprehensive Income (Loss):			
Unrealized investment gains/(losses) - net of taxes of $664, $(1,026) and $191, respectively	1,126	(1,741)	323
Reclassification adjustment for realized gains on investment securities included in net income - net of taxes of $(1), $(7) and $(171), respectively	(2)	(12)	(290)
Reclassification adjustment for realized losses on investment securities included in net income from discontinued operations - net of taxes of $273, $0 and $0, respectively	462	—	—
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $(1,967), $1,418 and $(590), respectively	(3,655)	2,634	(1,096)
Total other comprehensive income (loss)	(2,069)	881	(1,063)
Comprehensive income	190,208	113,175	77,737
Comprehensive income attributable to noncontrolling interests	(236)	(1,217)	(590)
Comprehensive income attributable to Avista Corporation shareholders	$ 189,972	$ 111,958	$ 77,147

The Accompanying Notes are an Integral Part of These Statements.

Table of Contents

CONSOLIDATED BALANCE SHEETS

Avista Corporation

As of December 31
Dollars in thousands

	2014	2013
Assets:		
Current Assets:		
Cash and cash equivalents	$ 22,143	$ 82,574
Accounts and notes receivable-less allowances of $4,888 and $44,309, respectively	171,925	221,343
Utility energy commodity derivative assets	1,525	3,022
Regulatory asset for utility derivatives	29,640	10,829
Investments and funds held for clients	—	96,688
Materials and supplies, fuel stock and natural gas stored	66,356	44,946
Deferred income taxes	14,794	24,788
Income taxes receivable	43,893	7,783
Other current assets	45,071	57,706
Total current assets	395,347	549,679
Net Utility Property:		
Utility plant in service	4,718,062	4,290,464
Construction work in progress	227,758	160,323
Total	4,945,820	4,450,787
Less: Accumulated depreciation and amortization	1,325,858	1,248,362
Total net utility property	3,619,962	3,202,425
Other Non-current Assets:		
Investment in exchange power-net	11,433	13,883
Investment in affiliated trusts	11,547	11,547
Goodwill	57,976	76,257
Intangible assets-net of accumulated amortization of $0 and $36,634, respectively	—	39,576
Long-term energy contract receivable of Spokane Energy	28,202	40,619
Other property and investments-net	42,016	58,555
Total other non-current assets	151,174	240,437
Deferred Charges:		
Regulatory assets for deferred income tax	100,412	71,421
Regulatory assets for pensions and other postretirement benefits	235,758	156,984
Other regulatory assets	91,920	102,915
Regulatory asset for unsettled interest rate swaps	77,063	—
Non-current utility energy commodity derivative assets	—	854
Non-current regulatory asset for utility derivatives	24,483	23,258
Other deferred charges	16,212	13,950
Total deferred charges	545,848	369,382
Total assets	$ 4,712,331	$ 4,361,923

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

As of December 31
Dollars in thousands

	2014	2013
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 112,974	$ 182,088
Client fund obligations	—	99,117
Current portion of long-term debt	6,424	358
Current portion of nonrecourse long-term debt of Spokane Energy	1,431	16,407
Short-term borrowings	105,000	171,000
Utility energy commodity derivative liabilities	18,045	10,875
Other current liabilities	141,395	145,495
Total current liabilities	385,269	625,340
Long-term debt	1,492,062	1,272,425
Nonrecourse long-term debt of Spokane Energy	—	1,431
Long-term debt to affiliated trusts	51,547	51,547
Long-term borrowings under committed line of credit	—	46,000
Regulatory liability for utility plant retirement costs	254,140	242,850
Pensions and other postretirement benefits	189,489	122,513
Deferred income taxes	710,342	535,343
Other non-current liabilities and deferred credits	146,240	130,318
Total liabilities	3,229,089	3,027,767
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Redeemable Noncontrolling Interests	—	15,889
Equity:		
Avista Corporation Shareholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 62,243,374 and 60,076,752 shares outstanding	999,960	896,993
Accumulated other comprehensive loss	(7,888)	(5,819)
Retained earnings	491,599	407,092
Total Avista Corporation shareholders' equity	1,483,671	1,298,266
Noncontrolling Interests	(429)	20,001
Total equity	1,483,242	1,318,267
Total liabilities and equity	$ 4,712,331	$ 4,361,923

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

	2014	2013	2012
Operating Activities:			
Net income	$ 192,277	$ 112,294	$ 78,800
Non-cash items included in net income:			
Depreciation and amortization	138,337	133,189	126,402
Provision for deferred income taxes	144,269	23,532	21,449
Power and natural gas cost amortizations (deferrals), net	(14,821)	(9,408)	6,702
Amortization of debt expense	3,692	3,813	3,803
Amortization of investment in exchange power	2,450	2,450	2,450
Stock-based compensation expense	8,114	6,218	5,792
Equity-related AFUDC	(8,808)	(6,066)	(4,055)
Pension and other postretirement benefit expense	22,943	42,067	39,838
Amortization of Spokane Energy contract	12,417	11,414	10,492
Write-off of Reardan wind generation capitalized costs	—	2,534	—
Gain on sale of Ecova	(160,612)	—	—
Other	9,009	12,982	5,256
Contributions to defined benefit pension plan	(32,000)	(44,263)	(44,000)
Changes in certain current assets and liabilities:			
Accounts and notes receivable	16,425	(32,675)	8,100
Materials and supplies, fuel stock and natural gas stored	(19,394)	2,509	4,551
Decrease (increase) in collateral posted for derivative instruments	(23,301)	(16,073)	9,695
Income taxes receivable	(36,110)	(5,006)	12,601
Other current assets	(7,117)	2,608	4,962
Accounts payable	(12,562)	(8,389)	30,189
Other current liabilities	32,060	8,827	(6,474)
Net cash provided by operating activities	267,268	242,557	316,553
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(325,516)	(294,363)	(271,187)
Other capital expenditures	(6,427)	(8,750)	(4,787)
Federal grant payments received	2,530	3,409	8,277
Cash received in acquisition, net of cash paid	15,007	—	—
Cash paid by subsidiaries for acquisitions, net of cash received	—	—	(50,310)
Decrease (increase) in funds held for clients	(18,931)	1,815	(6,811)
Purchase of securities available for sale	(12,267)	(35,949)	(100,374)
Sale and maturity of securities available for sale	14,612	22,960	137,999
Proceeds from sale of Ecova, net of cash sold	229,903	—	—
Other	(2,647)	(1,339)	(7,475)
Net cash used in investing activities	(103,736)	(312,217)	(294,668)

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

	2014	2013	2012
Financing Activities:			
Net increase (decrease) in short-term borrowings	$ (66,000)	$ 119,000	$ (9,000)
Borrowings from Ecova line of credit	—	3,000	33,000
Repayment of borrowings from Ecova line of credit	(46,000)	(11,000)	(14,000)
Proceeds from issuance of long-term debt	150,000	90,000	80,000
Redemption and maturity of long-term debt	(39,971)	(50,462)	(11,492)
Maturity of nonrecourse long-term debt of Spokane Energy	(16,407)	(14,965)	(13,669)
Cash received (paid) for settlement of interest rate swap agreements	5,429	2,901	(18,547)
Issuance of common stock, net of issuance costs	4,060	4,609	29,079
Repurchase of common stock	(79,856)	—	—
Cash dividends paid	(78,314)	(73,276)	(68,552)
Increase (decrease) in client fund obligations	16,216	11,278	(30,996)
Payment to noncontrolling interests for sale of Ecova	(54,179)	—	—
Payment to option holders and redeemable noncontrolling interests for sale of Ecova	(20,871)	—	—
Other	1,930	(4,315)	3,094
Net cash provided by (used in) financing activities	(223,963)	76,770	(21,083)
Net increase (decrease) in cash and cash equivalents	(60,431)	7,110	802
Cash and cash equivalents at beginning of year	82,574	75,464	74,662
Cash and cash equivalents at end of year	$ 22,143	$ 82,574	$ 75,464
Supplemental Cash Flow Information:			
Cash paid during the year:			
Interest	$ 73,526	$ 75,411	$ 74,900
Income taxes (net of refunds of $35,573, $123 and $11,584, respectively)	45,416	44,772	8,069
Non-cash financing and investing activities:			
Accounts payable for capital expenditures	26,959	12,723	21,331
Valuation adjustment for redeemable noncontrolling interests	(15,873)	10,704	(10,104)
Receivable for escrow amounts associated with the sale of Ecova	13,079	—	—
Non-cash stock issuance for acquisition of AERC	150,119	—	—
Contingent consideration by subsidiary for acquisition	—	—	375

The Accompanying Notes are an Integral Part of These Statements.

Table of Contents

CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS

Avista Corporation

For the Years Ended December 31
Dollars in thousands

	2014	2013	2012
Common Stock, Shares:			
Shares outstanding at beginning of year	60,076,752	59,812,796	58,422,781
Shares issued through equity compensation plans	51,127	58,002	245,661
Shares issued through Employee Investment Plan (401-K)	33,168	42,073	45,715
Shares issued through Dividend Reinvestment Plan	110,501	163,881	167,448
Shares issued through sales agency agreements	—	—	931,191
Shares issued for acquisition	4,501,441	—	—
Shares repurchased	(2,529,615)	—	—
Shares outstanding at end of year	62,243,374	60,076,752	59,812,796
Common Stock, Amount:			
Balance at beginning of year	$ 896,993	$ 889,237	$ 855,188
Equity compensation expense	7,676	6,002	5,716
Issuance of common stock through equity compensation plans	108	(1,342)	1,535
Issuance of common stock through Employee Investment Plan (401-K)	1,005	1,127	1,165
Issuance of common stock through Dividend Reinvestment Plan	3,441	4,360	4,226
Issuance of common stock through sales agency agreements, net of issuance costs	—	—	23,383
Issuance of common stock for acquisition, net of issuance costs	149,625	—	—
Repurchase of common stock	(40,486)	—	—
Equity transactions of consolidated subsidiaries	(1,062)	(3,007)	(1,015)
Payment to option holders and redeemable noncontrolling interests for sale of Ecova	(20,871)	—	—
Excess tax benefits	3,531	616	(961)
Balance at end of year	999,960	896,993	889,237
Accumulated Other Comprehensive Loss:			
Balance at beginning of year	(5,819)	(6,700)	(5,637)
Other comprehensive income (loss)	(2,069)	881	(1,063)
Balance at end of year	(7,888)	(5,819)	(6,700)
Retained Earnings:			
Balance at beginning of year	407,092	376,940	336,150
Net income attributable to Avista Corporation shareholders	192,041	111,077	78,210
Cash dividends paid (common stock)	(78,314)	(73,276)	(68,552)
Repurchase of common stock	(39,370)	—	—
Expiration of subsidiary noncontrolling interests redemption rights	—	—	23,805
Valuation adjustments and other noncontrolling interests activity	10,150	(7,649)	7,327
Balance at end of year	491,599	407,092	376,940
Total Avista Corporation shareholders' equity	$ 1,483,671	$ 1,298,266	$ 1,259,477

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS (continued)

Avista Corporation

For the Years Ended December 31
Dollars in thousands

	2014	2013	2012
Noncontrolling Interests:			
Balance at beginning of year	$ 20,001	$ 17,658	$ 174
Net income attributable to noncontrolling interests	240	1,066	451
Deconsolidation of variable interest entity	—	—	(673)
Issuance of subsidiary noncontrolling interests	—	480	—
Purchase of subsidiary noncontrolling interests	—	(4,182)	(117)
Expiration of subsidiary noncontrolling interests redemption rights	—	—	17,790
Deconsolidation of noncontrolling interests related to sale of Ecova	(23,612)	—	—
Other	2,942	4,979	33
Balance at end of year	(429)	20,001	17,658
Total equity	$ 1,483,242	$ 1,318,267	$ 1,277,135
Redeemable Noncontrolling Interests:			
Balance at beginning of year	$ 15,889	$ 4,938	$ 51,809
Net income attributable to noncontrolling interests	(4)	151	139
Issuance of subsidiary noncontrolling interests	—	—	3,714
Purchase of subsidiary noncontrolling interests	(12)	(405)	(784)
Expiration of subsidiary noncontrolling interests redemption rights	—	—	(41,595)
Valuation adjustments and other noncontrolling interests activity	(15,873)	11,205	(8,345)
Balance at end of year	$ —	$ 15,889	$ 4,938

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 primarily an electric and natural gas utility with certain other business ventures. Avista Utilities is an operating division of Avista Corp., comprising the regulated utility operations in the Pacific Northwest. Avista Utilities provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Utilities also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Utilities has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Utilities also supplies electricity to a small number of customers in Montana, most of whom are employees who operate Avista Utilities' Noxon Rapids generating facility.

On July 1, 2014, Avista Corp. completed its acquisition of Alaska Energy and Resources Company (AERC), and as of that date, AERC is a wholly-owned subsidiary of Avista Corp. The primary subsidiary of AERC is Alaska Electric Light and Power Company (AEL&P), comprising the regulated utility operations in Alaska. The results of AERC for only the final six months of 2014 are included in the overall results of Avista Corp. See Note 4 for information regarding the acquisition of AERC.

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). During the first half of the year, Avista Capital’s subsidiaries included Ecova, Inc. (Ecova), which was an 80.2 percent owned subsidiary prior to its disposition on June 30, 2014. Ecova was 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 5 for information regarding the disposition of Ecova and Note 23 for business segment information.

Basis of Reporting

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries and other majority owned subsidiaries and variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Ecova's revenues and expenses are included in the Consolidated Statements of Income in discontinued operations; however, as of June 30, 2014 and for all subsequent reporting periods there are no balance sheet amounts included for Ecova. All tables throughout the Notes to Consolidated Financial Statements that present Consolidated Statements of Income information were revised to include only the amounts from continuing operations. 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 (GAAP) requires management to make estimates and assumptions that affect the amounts reported for assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include:

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- goodwill impairment testing,
- 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, Oregon and Alaska.

Regulation

The Company is subject to state regulation in Washington, Idaho, Montana, Oregon and Alaska. 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. AEL&P does not have booked out transactions. 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. 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.

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

	2014	2013
Unbilled accounts receivable	$ 80,718	$ 81,059

Other Non-Utility Revenues

Revenues from the other businesses are primarily derived from the operations of AM&D 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 2014, 2013 and 2012.

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:

	2014	2013	2012
Avista Utilities			
Ratio of depreciation to average depreciable property	2.97%	2.90%	2.92%
Alaska Electric Light and Power Company			
Ratio of depreciation to average depreciable property	2.43%	—%	—%

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

	Avista Utilities	Alaska Electric Light and Power Company
Electric thermal/other production	40	36
Hydroelectric production	79	45
Electric transmission	58	39
Electric distribution	35	38
Natural gas distribution property	46	N/A

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):

	2014	2013	2012
Utility taxes	$ 58,250	$ 55,565	$ 53,716

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 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:

	2014	2013	2012
Avista Utilities			
Effective AFUDC rate	7.64%	7.64%	7.62%
Alaska Electric Light and Power Company			
Effective AFUDC rate	10.37%	—%	—%

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 19 for further information.

Other Income - Net

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

	2014	2013	2012
Interest income	$ 987	$ 754	$ 944
Interest on regulatory deferrals	220	126	68
Equity-related AFUDC	8,808	6,066	4,055
Net gain (loss) on investments	276	(3,378)	(3,343)
Other income	1,055	1,599	989
Total	$ 11,346	$ 5,167	$ 2,713

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 18 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):

	2014	2013	2012
Allowance as of the beginning of the year	$ 44,309	$ 44,155	$ 43,958
Additions expensed during the year	5,296	5,099	4,213
Net deductions (1)	(44,717)	(4,945)	(4,016)
Allowance as of the end of the year	$ 4,888	$ 44,309	$ 44,155

(1) During the second quarter of 2014, the Company received $15.0 million in gross proceeds related to the settlement of its California wholesale power markets litigation. The gross proceeds effectively settled all outstanding receivables and payables at Avista Energy (which had been fully reserved against since 2001). As a result of the settlement, the Company reversed $15.0 million of the allowance, which was recorded as a reduction to non-utility other operating expenses on the Consolidated Statements of Income, and the remainder of the receivables, payables and allowance were removed from the Consolidated Balance Sheets (and had no effect on net income). See Note 20 for additional discussion of the settlement in the California wholesale power markets litigation.

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):

	2014	2013
Materials and supplies	$ 32,483	$ 28,747
Fuel stock	5,142	3,170
Natural gas stored	28,731	13,029
Total	$ 66,356	$ 44,946

Investments and Funds Held for Clients and Client Fund Obligations

In connection with its bill paying services, Ecova collected funds from its clients and remitted the funds to the appropriate utility or other service provider. Some of the funds collected were invested by Ecova and classified as investments and funds held for clients, and a related liability for client fund obligations was recorded. Investments and funds held for clients included cash and cash equivalent investments, money market funds and investment securities classified as available for sale. Ecova did not invest the funds directly for the clients' benefit; therefore, Ecova bore the risk of loss associated with the investments. As of June 30, 2014 and for all subsequent reporting periods there are no longer any investments and funds held for clients due to the disposition of Ecova.

Investments and funds held for clients as of December 31, 2013 were as follows (dollars in thousands):

	Amortized Cost (1)	Unrealized Gain (Loss)	Fair Value
Cash and cash equivalents	$ 16,147	$ —	$ 16,147
Money market funds	11,180	—	11,180
Securities available for sale:			
U.S. government agency	63,633	(2,555)	61,078
Municipal	3,497	21	3,518
Corporate fixed income – financial	3,000	—	3,000
Corporate fixed income – industrial	753	12	765
Certificates of deposit	1,000	—	1,000
Total securities available for sale	71,883	(2,522)	69,361
Total investments and funds held for clients	$ 99,210	$ (2,522)	$ 96,688

(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 were classified as a current asset since these funds were held for the purpose of satisfying the client fund obligations. As of December 31, 2013 approximately 95 percent of the investment portfolio was rated AA-, Aa3 and higher by nationally recognized statistical rating organizations. All fixed income securities were rated as investment grade as of December 31, 2013.

Ecova management reviewed its investments continuously for indicators of other-than-temporary impairment. To make this determination, management employed a methodology that considers available quantitative and qualitative evidence in evaluating potential impairment of its investments. If the cost of an investment exceeded its fair value, management evaluated, among other factors, general market conditions, credit quality of instrument issuers, the length of time and extent to which the fair value was less than cost, and whether it had plans to sell the security or it was more-likely-than not that the Company would be required to sell the security before recovery. Management also considered 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 was determined to be other-than-temporary, an impairment charge was recorded in earnings and a new cost basis in the investment was established. Based on management's analysis, securities available for sale did not meet the criteria for other-than-temporary impairment as of December 31, 2013.

The following is a summary of the disposition of available-for-sale securities during the years ended December 31 (dollars in thousands):

	2014	2013
Proceeds from sales, maturities and calls	$ 14,612	$ 22,960
Gross realized gains	3	19
Gross realized losses (1)	(735)	—

(1) The gross realized losses for 2014 were included in the determination of the gain on the disposal of Ecova and were not the result of selling any individual securities.

Contractual maturities of securities available for sale as of December 31, 2013 were as follows (dollars in thousands):

	Due within 1 year	After 1 but within 5 years	After 5 but within 10 years	After 10 years	Total
December 31, 2013	$ 5,382	$ 12,745	$ 48,310	$ 2,924	$ 69,361

Actual maturities may differ due to call or prepayment rights and the effective maturity was 3.0 years as of December 31, 2013.

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 has recorded the amount of estimated retirement costs collected from customers (that do not represent legal or contractual obligations) and included them as a regulatory liability on the Consolidated Balance Sheets in the following amounts as of December 31 (dollars in thousands):

	2014	2013
Regulatory liability for utility plant retirement costs	$ 254,140	$ 242,850

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 combination of discounted cash flow models and a market approach on at least an annual basis or more frequently if impairment indicators arise. The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2014 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	AEL&P	Other	Accumulated Impairment Losses	Total
Balance as of January 1, 2013	$ 70,713	$ —	$ 12,979	$ (7,733)	$ 75,959
Adjustments	298	—	—	—	298
Balance as of the December 31, 2013	71,011	—	12,979	(7,733)	76,257
Adjustments	112	—	—	—	112
Goodwill sold during the year	(71,123)	—	—	—	(71,123)
Goodwill acquired during the year	—	52,730	—	—	52,730
Balance as of the December 31, 2014	$ —	$ 52,730	$ 12,979	$ (7,733)	$ 57,976

Accumulated impairment losses are attributable to the other businesses. The goodwill sold during the year relates to the Ecova disposition, which occurred on June 30, 2014. See Note 5 for information regarding this sales transaction. The goodwill acquired during the year relates to the acquisition of AERC and the goodwill associated with this acquisition is not deductible for tax purposes. See Note 4 for information regarding this business acquisition and Note 23 regarding the Company's reportable segments.

Intangible Assets

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

	2014	2013	2012
Intangible asset amortization	$ 5,898	$ 11,828	$ 10,435

All of the intangible assets were related to Ecova, which was disposed of as of June 30, 2014. As such, there are no intangible assets remaining as of December 31, 2014 and there is no amortization expense expected in future years. The amortization expense disclosed in the table above is included in discontinued operations for all periods presented. See Note 5 for information regarding the Ecova sales transaction.

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

	Estimated Useful Lives	2013
Client relationships	2 - 12 years	$ 33,562
Software development costs	3 - 7 years	39,327
Other	1 - 10 years	3,321
Total intangible assets		76,210
Client relationships accumulated amortization		(12,336)
Software development costs accumulated amortization		(21,861)
Other accumulated amortization		(2,437)
Total accumulated amortization		(36,634)
Total intangible assets - net		$ 39,576

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 a derivative depends on the intended use of such derivative and the resulting designation.

The UTC and the IPUC issued accounting orders authorizing Avista Utilities to offset energy 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 delivery. 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 periods of delivery, 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. 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.

For interest rate swap agreements, each period Avista Utilities records all mark-to-market gains and losses as assets and liabilities and records offsetting regulatory assets and liabilities, such that there is no income statement impact. This is similar to the treatment of energy commodity derivatives described above. Upon settlement of 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 term of the associated debt.

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 16 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 22 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

At December 31, 2013, certain option holders of Ecova had the right to put their shares back to Ecova at their discretion during an annual put window. Stock options and other outstanding redeemable stock were valued at their maximum redemption amount which was equal to their intrinsic value (fair value less exercise price). Due to the disposition of Ecova, as of June 30, 2014 there are no longer any redeemable noncontrolling interests.

Accumulated Other Comprehensive Loss

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

	2014	2013
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $(4,247) and $(2,280), respectively	$ (7,888)	$ (4,233)
Unrealized gain (loss) on securities available for sale - net of taxes of $0 and $(936), respectively (1)	—	(1,586)
Total accumulated other comprehensive loss	$ (7,888)	$ (5,819)

(1) This entire balance was related to Ecova, which was disposed of as of June 30, 2014.

The following table details the reclassifications out of accumulated other comprehensive loss by component for the years ended December 31 (dollars in thousands):

	Amounts Reclassified from Accumulated Other Comprehensive Loss		
Details about Accumulated Other Comprehensive Loss Components	2014	2013	Affected Line Item in Statement of Income
Realized gains on investment securities	$ 3	$ 19	(a)
Realized losses on investment securities	(735)	—	(a)
	(732)	19	Total before tax
	272	(7)	Tax expense (a)
	$ (460)	$ 12	Net of tax
Amortization of defined benefit pension items			
Amortization of net prior service cost	$ 1,094	$ (10,681)	(b)
Amortization of net loss	83,301	(142,794)	(b)
Adjustment due to effects of regulation	(78,773)	149,423	(b)
	5,622	(4,052)	Total before tax
	(1,967)	1,418	Tax benefit
	$ 3,655	$ (2,634)	Net of tax

(a) These amounts were included as part of net income from discontinued operations for all periods presented (see Note 5 for additional details).

(b) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 10 for additional details).

Appropriated Retained Earnings

In accordance with the hydroelectric licensing requirements of section 10(d) of the Federal Power Act (FPA), the Company maintains an appropriated retained earnings account for any earnings in excess of the specified rate of return on the Company's investment in the licenses for its various hydroelectric projects. The rate of return on investment is specified in the various hydroelectric licensing agreements for the Clark Fork River and Spokane River. Per section 10(d) of the FPA, the Company must maintain these excess earnings in an appropriated retained earnings account until the termination of the licensing agreements or apply them to reduce the net investment in the licenses of the hydroelectric projects at the discretion of the FERC. The Company typically calculates the earnings in excess of the specified rate of return on an annual basis, usually during the second quarter.

In addition to the hydroelectric project licenses identified above for Avista Utilities, the requirements of section 10(d) of the FPA also apply to the Lake Dorothy, the Annex Creek and the Salmon Creek licenses, of AEL&P. These requirements do not apply to the Snettisham hydroelectric project at AEL&P because it is not required to be licensed by the FERC. The Company is still evaluating these licenses to determine an amount of appropriated retained earnings to record and this analysis is expected to be completed in 2015. The Company does not expect this to result in a material amount of appropriated retained earnings.

The appropriated retained earnings amounts included in retained earnings were as follows as of December 31 (dollars in thousands):

	2014	2013
Appropriated retained earnings	$ 14,270	$ 9,714

Operating Leases

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from 1 to forty-five years. Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year were not material as of December 31, 2014.

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 material loss may be incurred. See Note 20 for further discussion of the Company's commitments and contingencies.

Reclassifications

Certain prior year amounts on the Company's Consolidated Statements of Cash Flows and Consolidated Statements of Equity and Redeemable Noncontrolling Interests were reclassified to conform to the current year presentation. In the current year Consolidated Statements of Cash Flows, "Decrease (increase) in collateral posted for derivative instruments" and "Taxes receivable" were added as their own line items. These were previously included in "Other current assets" in the operating activities section. Also, "Long-term debt and short-term borrowings issuance costs", "Purchase of subsidiary noncontrolling interest" and "Issuance of subsidiary noncontrolling interest" were previously included as their own line items in the financing activities. These are now included in "Other" in the financing activities section. In the current year Consolidated Statements of Equity and Redeemable Noncontrolling Interests "Excess tax benefits (shortfalls)" was added as its own line item in the common stock, amount section. This was previously included in "Issuance of common stock through equity compensation plans" and "Equity transactions of consolidated subsidiaries" in the common stock, amount section.

NOTE 2. NEW ACCOUNTING STANDARDS

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. The core principle of the revenue model is that an entity identifies the various performance obligations in a contract, allocates the transaction price among the performance obligations and recognizes revenue as the entity satisfies the performance obligations. This ASU is effective for periods beginning after December 15, 2016 and early adoption is not permitted. However, while this ASU is not effective until 2017, it will require retroactive application to all periods presented in the financial statements. As such, at adoption in 2017, amounts in 2015 and 2016 may have to be revised or a cumulative adjustment to opening retained earnings may have to be recorded. The Company is evaluating this standard and cannot, at this time, estimate the potential impact to its future financial condition, results of operations and cash flows.

In August 2014, the FASB issued ASU No. 2014-15, "Presentation of Financial Statements - Going Concern (ASC Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern." The new standard provides guidance around management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern within one year of the date the financial statements are issued. The Company must provide certain disclosures if conditions or events raise substantial doubt about the Company’s ability to continue as a going concern. The new standard is effective for periods beginning after December 15, 2016; however, early adoption is permitted. The Company evaluated this standard and determined that it will not early adopt this standard. As such, there is no impact to the Company's financial condition, results of operations and cash flows in the current year.

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 Kootenai County, Idaho, owned by an unrelated third-party (Rathdrum Power LLC), through 2026.

Avista Corp. has a variable interest in the PPA. Accordingly, Avista Corp. made an evaluation of which interest holders have the power to direct the activities that most significantly impact the economic performance of the entity and which interest holders have the obligation to absorb losses or receive benefits that could be significant to the entity. Avista Corp. pays a fixed capacity and operations and maintenance payment and certain monthly variable costs under the PPA. Under the terms of the PPA, Avista Corp. makes the dispatch decisions, provides all natural gas fuel and receives all of the electric energy output from the Lancaster Plant. However, Rathdrum Power LLC (the owner) controls the daily operation of the Lancaster Plant and makes operating and maintenance decisions. Rathdrum Power LLC controls all of the rights and obligations of the Lancaster Plant after the expiration of the PPA in 2026. It is estimated that the plant will have 15 to 25 years of useful life after that time. Rathdrum Power LLC bears the maintenance risk of the plant and will receive the residual value of the Lancaster Plant. Avista Corp. has no debt or equity investments in the Lancaster Plant and does not provide financial support through liquidity arrangements or other commitments (other than the PPA). Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Lancaster Plant. Accordingly, neither the Lancaster Plant nor Rathdrum Power LLC is included in Avista Corp.’s consolidated financial statements. The Company has a future contractual obligation of approximately $323.7 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). The PPA relates to a wind-driven power generation project that was developed by Palouse Wind in Whitman County, Washington and under the terms of the PPA, the Company acquires all of the power and renewable attributes produced by the wind project for a fixed price per MWh, which escalates annually, without consideration for market fluctuations. The wind project has a nameplate capacity of approximately 105 MW and is expected to produce approximately 40 aMW annually. The project was completed and energy deliveries began during the fourth quarter of 2012. Under the PPA, the Company has an annual option to purchase the wind project following the 10^{th} 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 $595.6 million under the PPA (representing the charges associated with purchasing the energy and renewable attributes through 2042) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

NOTE 4. BUSINESS ACQUISITIONS

Alaska Energy and Resources Company

On July 1, 2014, the Company completed its acquisition of AERC, based in Juneau, Alaska. As of July 1, 2014 AERC is a wholly-owned subsidiary of Avista Corp.

The primary subsidiary of AERC is AEL&P, a regulated utility which provides electric services to 16,394 customers in the City and Borough of Juneau, Alaska. As of December 31, 2014, AEL&P has 59 full-time employees. AEL&P has a firm retail peak load of approximately 68 MW. AEL&P owns four hydroelectric generating facilities, having a total present capacity of 24.7 MW, and has a power purchase commitment for the output of the Snettisham hydroelectric project, having a present capacity of 78 MW, for a total hydroelectric capacity of 102.7 MW. AEL&P is not interconnected to any other electric system. AEL&P also has 93.9 MW of diesel generating capacity to provide back-up service to firm customers when necessary.

In addition to the regulated utility, AERC owns AJT Mining, which is an inactive mining company holding certain properties.

The purpose of the acquisition was to expand and diversify Avista Corp.'s energy assets and deliver long-term value to its customers, communities and investors.

In connection with the closing, on July 1, 2014 Avista Corp. issued 4,500,014 new shares of common stock to the shareholders of AERC based on a contractual formula that resulted in a price of $32.46 per share, reflecting a purchase price of $170.0 million, plus acquired cash, less outstanding debt and other closing adjustments.

The $32.46 price per share of Avista Corp. common stock was determined based on the average closing stock price of Avista Corp. common stock for the 10 consecutive trading days immediately preceding, but not including, the trading day prior to July 1, 2014. This value was used solely for determining the number of shares to issue based on the adjusted contract closing price (see reconciliation below). The fair value of the consideration transferred at the closing date was based on the closing stock price of Avista Corp. common stock on July 1, 2014, which was $33.35 per share.

On October 1, 2014, a working capital adjustment was made in accordance with the agreement and plan of merger which resulted in Avista Corp. issuing an additional 1,427 shares of common stock to the shareholders of AERC. The number of shares issued on October 1, 2014 was based on the same contractual formula described above. The fair value of the new shares issued in October was $30.71 per share, which was the closing stock price of Avista Corp. common stock on that date.

The contract acquisition price and the fair value of consideration transferred for AERC were as follows (in thousands, except "per share" and number of shares data):

		July 1, 2014
Contract acquisition price (using the calculated $32.46 per share common stock price)		
Gross contract price	$	170,000
Acquired cash		19,704
Acquired debt (excluding capital lease obligation)		(38,832)
Other closing adjustments (including the working capital adjustment)		(58)
Total adjusted contract price	$	150,814
Fair value of consideration transferred		
Avista Corp. common stock (4,500,014 shares at $33.35 per share)	$	150,075
Avista Corp. common stock (1,427 shares at $30.71 per share)		44
Cash		4,697
Fair value of total consideration transferred	$	154,816

The estimated fair value of assets acquired and liabilities assumed as of July 1, 2014 (after consideration of the working capital adjustment) were as follows (in thousands):

		July 1, 2014
Assets acquired:		
Current Assets:		
Cash	$	19,704
Accounts receivable - gross totals $3,928		3,851
Materials and supplies		2,017
Other current assets		999
Total current assets		26,571
Utility Property:		
Utility plant in service		113,964
Utility property under long-term capital lease		71,007
Construction work in progress		3,440
Total utility property		188,411
Other Non-current Assets:		
Non-utility property		6,660
Electric plant held for future use		3,711
Goodwill		52,730
Other deferred charges and non-current assets		5,368
Total other non-current assets		68,469
Total assets	$	283,451

Liabilities Assumed:		
Current Liabilities:		
Accounts payable	$	700
Current portion of long-term debt and capital lease obligations		3,773
Other current liabilities		2,902
Total current liabilities		7,375
Long-term debt		37,227
Capital lease obligations		68,840
Other non-current liabilities and deferred credits		15,193
Total liabilities	$	128,635
Total net assets acquired	$	154,816

The goodwill associated with this acquisition is not deductible for tax purposes.

The majority of AERC's operations are subject to the rate-setting authority of the RCA and are accounted for pursuant to GAAP, including the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for AERC's regulated operations provide revenues derived from costs, including a return on investment, of assets and liabilities included in rate base. Due to this regulation, the fair values of AERC's assets and liabilities subject to these rate-setting provisions are assumed to approximate their carrying values. There were not any identifiable intangible assets associated with this acquisition. The excess of the purchase consideration over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill at the acquisition date. The goodwill reflects the value paid for the expected continued growth of a rate-regulated business located in a defined service area with a constructive regulatory environment, the attractiveness of stable, growing cash flows, as well as providing a platform for potential future growth outside of the rate-regulated electric utility in Alaska.

The following table summarizes the supplemental pro forma information for the years ended December 31 related to the acquisition of AERC as if the acquisition had occurred on January 1, 2013 (dollars in thousands - unaudited):

	2014	2013
Actual Avista Corp. revenues from continuing operations (excluding AERC)	$ 1,450,918	$ 1,441,744
Supplemental pro forma AERC revenues (1)	46,467	41,594
Total pro forma revenues	1,497,385	1,483,338
Actual AERC revenues included in Avista Corp. revenues (1)	21,644	—
Actual Avista Corp. net income from continuing operations attributable to Avista Corp. shareholders (excluding AERC)	116,665	104,273
Actual Avista Corp. net income from discontinued operations attributable to Avista Corp. shareholders	72,224	6,804
Adjustment to Avista Corp.'s net income for acquisition costs (net of tax) (2)	870	(870)
Supplemental pro forma AERC net income (1)	8,806	9,328
Total pro forma net income	198,565	119,535
Actual AERC net income included in Avista Corp. net income (1)	$ 3,152	$ —

(1) AERC was acquired on July 1, 2014 and only the supplemental revenues and net income for the period July 1, 2014 to December 31, 2014 were included in the actual results of Avista Corp. for the year ended December 31, 2014.

(2) This adjustment is to treat all transaction costs as if they occurred on January 1, 2013 and to remove them from the periods in which they actually occurred. The transaction costs were expensed and presented in the Consolidated Statements of Income in other operating expenses within utility operating expenses. Since the start of the transaction through December 31, 2014, Avista Corp. has expensed $3.0 million (pre-tax) in total transaction fees. In addition to the amounts expensed, through December 31, 2014, Avista Corp. has included $0.4 million in fees associated with the issuance of

common stock for the transaction as a reduction to common stock. These fees do not impact the supplemental pro forma information above.

NOTE 5. DISCONTINUED OPERATIONS

On May 29, 2014, Avista Capital, the non-regulated subsidiary of Avista Corp., entered into a definitive agreement to sell its interest in Ecova to Cofely USA Inc., an indirect subsidiary of GDF SUEZ, a French multinational utility company, and an unrelated party to Avista Corp. The sales transaction was completed on June 30, 2014 for a sales price of $335.0 million in cash, less the payment of debt and other customary closing adjustments. At the closing of the transaction on June 30, 2014, Ecova became a wholly-owned subsidiary of Cofely USA Inc. and the Company will have no further involvement with Ecova after such date.

The purchase price of $335.0 million, as adjusted, was divided among the security holders of Ecova, including minority shareholders and option holders, pro rata based on ownership. Approximately $16.8 million (5 percent of the purchase price) will be held in escrow for 15 months from the closing of the transaction to satisfy certain indemnification obligations under the merger agreement. An additional $1.0 million is being held in escrow pending resolution of adjustments to working capital, which is expected to be resolved in early 2015.

Avista Capital and Cofely USA Inc. agreed to make an election under Section 338(h)(10) of the Internal Revenue Code (Code) of 1986, as amended, with respect to the purchase and sale of Ecova to allocate the merger consideration among the assets of Ecova deemed to have been acquired in the merger.

When all escrow amounts are released, the sales transaction is expected to provide cash proceeds to Avista Corp., net of debt, payment to option and minority holders, income taxes and transaction expenses, of $143.5 million (see reconciliation below) and result in a net gain of $69.7 million. The Company expects to receive the full amount of its portion of the remaining escrow accounts; therefore, these amounts were included in the gain calculation.

The summary of cash proceeds associated with the sales transaction are as follows (in thousands):

Reconciliation to Statement of Cash Flows		
Contract price	$	335,000
Closing adjustments		3,914
Gross proceeds from sale (1)		338,914
Cash sold in the transaction		(95,932)
Avista Corp. portion of proceeds held in escrow		(13,079)
Gross proceeds from sale of Ecova, net of cash sold (per Statement of Cash Flows)	$	229,903
Reconciliation of expected net proceeds		
Gross proceeds from sale (1)	$	338,914
Repayment of long-term borrowings under committed line of credit		(40,000)
Payment to option holders and redeemable noncontrolling interests		(20,871)
Payment to noncontrolling interests		(54,179)
Transaction expenses withheld from proceeds		(5,390)
Avista Corp. portion of proceeds held in escrow		(13,079)
Net proceeds to Avista Capital at transaction closing		205,395
Tax payments made in 2014		(74,842)
Estimated tax payments to be made in 2015		(172)
Avista Corp. portion of proceeds held in escrow to be received in the future		13,079
Total net proceeds related to sales transaction	$	143,460

(1) Of this total amount, approximately $16.8 million will be held in escrow for 15 months from the transaction closing date for any indemnity claims and an additional $1.0 million is being held in escrow pending resolution of adjustments to working capital, which is expected to be resolved in early 2015.

Prior to the completion of the sales transaction, Ecova was a reportable business segment. The major classes of assets and liabilities and their carrying amounts immediately prior to the completion of the sales transaction were as follows:

		June 30, 2014
Assets:		
Current Assets:		
Cash and cash equivalents	$	95,932
Accounts and notes receivable-less allowances of $410		32,070
Investments and funds held for clients		114,598
Income taxes receivable		2,548
Other current assets		8,908
Total current assets		254,056
Other Non-current Assets:		
Goodwill		71,123
Intangible assets-net of accumulated amortization of $42,266		37,185
Other property and investments-net		4,656
Total other non-current assets		112,964
Total assets		367,020
Liabilities:		
Current Liabilities:		
Accounts payable		72,453
Client fund obligations		115,333
Current portion of long-term debt		67
Other current liabilities		35,329
Total current liabilities		223,182
Long-term borrowings under committed line of credit		40,000
Other non-current liabilities		2,117
Total liabilities	$	265,299

Amounts reported in discontinued operations for 2012 through 2014 relate solely to the Ecova business segment. The following table presents amounts that were included in discontinued operations for the years ended December 31 (dollars in thousands):

		2014		2013		2012
Revenues	$	87,534	$	176,761	$	155,664
Gain on sale of Ecova (1)		160,612		—		—
Transaction expenses and accelerated employee benefits (2)		9,062		—		—
Gain on sale of Ecova, net of transaction expenses		151,550		—		—
Income before income taxes		156,025		13,177		3,494
Income tax expense		83,614		5,216		1,497
Net income from discontinued operations		72,411		7,961		1,997
Net income attributable to noncontrolling interests		(187)		(1,157)		(506)
Net income from discontinued operations attributable to Avista Corp. shareholders	$	72,224	$	6,804	$	1,491

(1) This represents the gross gain recorded to discontinued operations. The gain net of taxes and transactions expenses is $69.7 million.

(2) This represents Avista Corp.'s portion of the total transaction expenses. All transaction expenses paid on the Ecova sale were $11.0 million, of which $5.4 million were withheld from the net proceeds and the remainder were paid during the

second and third quarter of 2014. The transaction expenses were for legal, accounting and other consulting fees and the accelerated employee benefits related to employee stock options which were settled in accordance with the Ecova equity plan.

NOTE 6. DERIVATIVES AND RISK MANAGEMENT

The disclosures below in Note 6 apply only to Avista Corp. and Avista Utilities; AERC and its primary subsidiary AEL&P do not enter into derivative instruments.

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 the Company's resource procurement and management operations in the electric business, the Company engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve the Company's load obligations and the use of these resources to capture available economic value. The Company transacts 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 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, the Company makes 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 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 financial 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, 2014 that are expected to be settled in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWH	Financial (1) MWH	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWH	Financial (1) MWH	Physical (1) mmBTUs	Financial (1) mmBTUs
2015	522	2,547	21,111	120,780	326	2,951	3,428	99,023
2016	397	1,071	2,505	70,480	287	1,634	910	56,520
2017	397	—	675	24,230	286	290	—	15,420
2018	397	—	—	3,020	286	—	—	—
2019	235	—	—	1,800	158	—	—	—
Thereafter	—	—	—	—	—	—	—	—

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

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

Foreign Currency Exchange Contracts

A significant portion of Avista Utilities' natural gas supply (including fuel for power generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of Avista Utilities' short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices and settled within 60 days with U.S. dollars. Avista Utilities hedges a portion of the foreign currency risk by purchasing Canadian currency contracts when such commodity transactions are initiated. This risk has not had a material effect on the Company's financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations were included with natural gas supply costs for ratemaking. The following table summarizes the foreign currency hedges that the Company has entered into as of December 31 (dollars in thousands):

	2014	2013
Number of contracts	18	23
Notional amount (in United States dollars)	$ 5,474	$ 8,631
Notional amount (in Canadian dollars)	6,198	9,191

Interest Rate Swap Agreements

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt, and future borrowing requirements. The Finance Committee of the Board of Directors periodically reviews and discusses interest rate risk management processes, and it focuses on the steps management has undertaken to manage it. The Risk Management Committee also reviews the interest risk management plan. Avista Corp. manages interest rate exposure by limiting the 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. The Company also 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 swaps and U.S. Treasury lock 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 outstanding as of the balance sheet date indicated below (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
December 31, 2014	5	$ 75,000	2015
	5	95,000	2016
	3	45,000	2017
	9	205,000	2018
December 31, 2013	2	50,000	2014
	2	45,000	2015
	2	40,000	2016
	1	15,000	2017
	4	95,000	2018

In October 2014, the Company cash settled two interest rate swap contracts (notional aggregate amount of $50.0 million) and received a total of $5.4 million. The interest rate swap contracts were settled in connection with the pricing of $60.0 million of Avista Corp. first mortgage bonds that were issued in December 2014 (see Note 14). Upon settlement of 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 term of the associated debt.

As of December 31, 2014, the fair value of the outstanding interest rate swaps decreased significantly compared to December 31, 2013 (see the table below). The fair value decrease was the result of a net increase in the notional amount of outstanding swap agreements and a decline in market interest rates below the rates that were fixed in the outstanding swaps. The Company enters into interest rate swaps to reduce uncertainty related to the net effective interest cost for future long-term debt. The Company would be required to make cash payments to settle the interest rate swaps if the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, the Company receives cash to settle its interest rate swaps when prevailing market rates at the time of settlement exceed the fixed swap rates.

Summary of Outstanding Derivative Instruments

Until May 2014, Avista Corp. had a master netting agreement that governed the transactions of multiple affiliated legal entities that were parties to this agreement. This master netting agreement allowed for cross-commodity netting (i.e. netting physical power, physical natural gas, and financial transactions) and cross-affiliate netting for the parties to the agreement. Avista Corp. performed cross-commodity netting for each legal entity that was a party to the master netting agreement for presentation in the Consolidated Balance Sheets; however, Avista Corp. did not perform cross-affiliate netting because the Company believed that cross-affiliate netting may not be enforceable. Therefore, the requirements for cross-affiliate netting under ASC 210-20-45 were not applicable to Avista Corp. As of December 31, 2013, all derivatives for each affiliated entity under this master netting agreement were in a net liability position; therefore, there was no additional netting which required disclosure for the year 2013. In May 2014, this master netting agreement was terminated and each affiliated legal entity is now under their own separate agreement. As of December 31, 2014, the Company no longer has any agreements that allow cross-affiliate netting. The Company has multiple agreements with a variety of entities that allow for cross-commodity netting under ASC 815-10-45. The amounts recorded on the Consolidated Balance Sheet as of December 31, 2014 and 2013 for these particular entities reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of derivative instruments recorded on the Consolidated Balance Sheet as of December 31, 2014 (in thousands):

		Fair Value			
Derivative	Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet
Foreign currency contracts	Other current liabilities	$ 1	$ (21)	$ —	$ (20)
Interest rate contracts	Other current assets	966	(506)	—	460
Interest rate contracts	Other current liabilities	—	(7,325)	—	(7,325)
Interest rate contracts	Other non-current liabilities and deferred credits	—	(69,737)	28,880	(40,857)
Commodity contracts	Current utility energy commodity derivative assets	2,063	(538)	—	1,525
Commodity contracts	Current utility energy commodity derivative liabilities	66,421	(97,586)	13,120	(18,045)
Commodity contracts	Other non-current liabilities and deferred credits	29,594	(54,077)	2,390	(22,093)
Total derivative instruments recorded on the balance sheet		$ 99,045	$ (229,790)	$ 44,390	$ (86,355)

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

		Fair Value			
Derivative	Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet
Foreign currency contracts	Other current assets	$ 7	$ (6)	$ —	$ 1
Interest rate contracts	Other current assets	13,968	—	—	13,968
Interest rate contracts	Other property and investments - net	19,575	—	—	19,575
Commodity contracts	Current utility energy commodity derivative assets	7,416	(4,394)	—	3,022
Commodity contracts	Non-current utility energy commodity derivative assets	7,610	(6,756)	—	854
Commodity contracts	Current utility energy commodity derivative liabilities	23,455	(37,306)	2,976	(10,875)
Commodity contracts	Other non-current liabilities and deferred credits	17,101	(41,213)	5,756	(18,356)
Total derivative instruments recorded on the balance sheet		$ 89,132	$ (89,675)	$ 8,732	$ 8,189

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, 2014, the Company had cash deposited as collateral of $20.6 million and letters of credit of $14.5 million outstanding related to its energy derivative contracts. The Company also had deposited cash in the amount of $28.9 million and letters of credit of $10.9 million as collateral for its interest rate swap derivative contracts. The Consolidated Balance Sheet at December 31, 2014 reflects the offsetting of $44.4 million of cash collateral against net derivative positions where a legal right of offset exists. As of December 31, 2013, the Company had cash deposited as collateral of $26.1 million and letters of credit of

$20.3 million outstanding related to its energy derivative contracts. The Consolidated Balance Sheet at December 31, 2013 reflects the offsetting of $8.7 million of cash collateral against net derivative positions where a legal right of offset exists. As of December 31, 2014 and December 31, 2013, the Company did not hold any cash as collateral from counterparties under energy derivative contracts.

Certain of the Company's derivative instruments contain provisions that require the Company to maintain an "investment grade" credit rating from the major credit rating agencies. If the Company's credit ratings were to fall below "investment grade," it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2014 was $12.9 million. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2014, the Company could be required to post $16.2 million of additional collateral to its counterparties. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2013 was $13.3 million. If the credit-risk-related contingent features underlying these agreements had been triggered on December 31, 2013, the Company could have been required to post $12.6 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.

The Company enters into bilateral transactions with various counterparties. The Company also trades 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):

	2014	2013
Utility plant in service	$ 350,518	$ 349,781
Accumulated depreciation	(239,845)	(239,538)

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):

	2014	2013
Avista Utilities:		
Electric production	$ 1,171,002	$ 1,141,790
Electric transmission	603,909	569,056
Electric distribution	1,360,185	1,284,428
Electric construction work-in-progress (CWIP) and other	311,807	276,582
Electric total	3,446,903	3,271,856
Natural gas underground storage	41,963	41,248
Natural gas distribution	810,487	762,044
Natural gas CWIP and other	57,088	47,751
Natural gas total	909,538	851,043
Common plant (including CWIP)	394,027	327,888
Total Avista Utilities	4,750,468	4,450,787
Alaska Electric Light and Power Company:		
Electric production	71,969	—
Electric transmission	18,392	—
Electric distribution	17,936	—
Electric production held under long-term capital lease	71,007	—
Electric CWIP and other	7,893	—
Electric total	187,197	—
Common plant	8,155	—
Total Alaska Electric Light and Power Company	195,352	—
Ecova (1)	—	31,865
Other (1)	25,803	20,132
Total	$ 4,971,623	$ 4,502,784

(1) Included in other property and investments-net on the Consolidated Balance Sheets. Ecova was sold on June 30, 2014; therefore, there is no property and equipment associated with them as of December 31, 2014. Accumulated depreciation was $26.4 million as of December 31, 2013 for Ecova. Accumulated depreciation was $10.8 million as of December 31, 2014 and $11.4 million as of December 31, 2013 for the other businesses. The decrease in accumulated depreciation for the other businesses was due to the sale of certain assets which were nearing the end of their useful lives during 2014.

NOTE 9. ASSET RETIREMENT OBLIGATIONS

The Company records the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred. When the liability is initially recorded, the associated costs of the ARO 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 ARO 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 AROs 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):

	2014	2013	2012
Asset retirement obligation at beginning of year	$ 2,859	$ 3,168	$ 3,513
Liability settled	(41)	(263)	(559)
Accretion expense (income)	210	(46)	214
Asset retirement obligation at end of year	$ 3,028	$ 2,859	$ 3,168

In addition to the AROs described above, on December 19, 2014, the EPA issued its pre-publication version of a final rule regarding the disposal of coal ash. This rule is expected to be published in the Federal Register in early 2015 and the rule is not effective until six months after it is published in the Federal Register; therefore, the Company does not have a revised legal obligation until the third quarter of 2015 when the rule is effective. The Company will continue to review the potential costs of complying with the new coal ash rule and its impacts on the valuation of the Company's ARO at Colstrip to restore ponds to their original states. The Company cannot currently estimate the cost impact of future regulation. If the Company incurs incremental costs as a result of these regulations, it would seek recovery in customer rates.

NOTE 10. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The pension and other postretirement benefit plans described below only relate to Avista Utilities and AEL&P. Most other subsidiary employees have salary deferral 401(k) savings plans that are defined contribution plans and these have historically not been significant to the Company.

Avista Utilities

The Company has a defined benefit pension plan covering the majority of 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 $32.0 million in cash to the pension plan in 2014, $44.3 million in 2013 and $44.0 million in 2012. The Company expects to contribute $12.0 million in cash to the pension plan in 2015.

In October 2013, the Company revised its defined benefit pension plan such that as of January 1, 2014 the plan is closed to non-union employees hired or rehired by the Company on or after January 1, 2014. Actively employed non-union employees that were hired prior to January 1, 2014 and who were at that date covered under the defined benefit pension plan will continue accruing benefits as originally specified in the plan. A new and separate defined contribution 401(k) plan replaced the defined benefit pension plan for non-union employees hired or rehired on or after January 1, 2014. Under the new defined contribution plan, the Company provides a non-elective contribution as a percentage of each employee's pay based on his or her age. This new defined contribution plan is in addition to the existing 401(k) plan in which the Company matches a portion of the pay deferred by each participant. In addition to the changes above, the Company revised the lump sum calculation for non-union participants who retire under the defined benefit pension plan on or after January 1, 2014 to provide retiring employees the election of a lump sum amount equivalent to the present value of the benefits based upon applicable discount rates. In April 2014, the local union in Oregon for the IBEW accepted the above plan changes in the latest collective bargaining agreement, and the plan changes are effective for Oregon union workers hired or rehired on or after April 1, 2014. Employees subject to IBEW local agreements for Washington, Idaho and Montana are not affected by these changes and they continue to be covered by the defined benefit pension plan and are not included in the new defined contribution plan.

For the estimated pension liability and pension costs as of December 31, 2014, the Company adopted the Society of Actuaries' mortality table that was published in 2014 as its base table, which reflects improved longevity of plan participants based on studies of wide populations through 2007 (RP-2014). The Company also adopted a modified form of the Society of Actuaries' MP-2014 mortality improvement scale, which projects improvements to life expectancies after the RP-2014 historic period that ended in 2007. For years subsequent to 2007, the Company reviewed data from other sources, including the Human Mortality Database, maintained by the University of California, Berkley and the Max Planck Institute for Demographic Research, and the Trustee's Report provided by the Social Security Administration. Based on data subsequent to 2007, the mortality improvement scale included in the MP-2014 for the three-year period immediately following its inception (2007) was shown to significantly overstate the actual mortality improvement for those years. As such, the mortality improvement scale the Company adopted assumes a lower rate of improved life expectancy than the MP-2014 scale as published.

The Company also has a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to executive officers and certain key employees of the Company. The SERP is intended to provide benefits to individuals 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):

	2015	2016	2017	2018	2019	Total 2020-2024
Expected benefit payments	$ 27,938	$ 29,109	$ 30,157	$ 31,407	$ 32,979	$ 184,794

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 the majority of its retired employees at Avista Utilities. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. In October 2013, the Company revised the health care benefit plan such that beginning on January 1, 2020, the methods for calculating health insurance premiums for non-union retirees under age 65 and active Company employees were revised to establish separate health insurance premiums for each group. In addition, for non-union employees hired or rehired on or after January 1, 2014, upon retirement the Company will provide access to its retiree medical plan, but will no longer contribute towards their medical premiums and each employee would pay the full cost of premiums upon retirement. In April 2014, the local union in Oregon for the IBEW accepted the above plan changes in the latest collective bargaining agreement, and the plan changes are effective for Oregon union workers hired or rehired on or after April 1, 2014.

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):

	2015	2016	2017	2018	2019	Total 2020-2024
Expected benefit payments	$ 7,138	$ 7,487	$ 7,475	$ 7,589	$ 7,767	$ 36,076

The Company expects to contribute $7.1 million to other postretirement benefit plans in 2015, 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, 2014 and 2013 and the components of net periodic benefit costs for the years ended December 31, 2014, 2013 and 2012 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2014	2013	2014	2013
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 527,004	$ 584,619	$ 108,249	$ 132,541
Service cost	15,757	19,045	1,844	4,144
Interest cost	26,224	23,896	5,226	5,216
Actuarial (gain)/loss	97,128	(78,234)	18,714	(18,017)
Plan change	—	277	—	(10,788)
Transfer of accrued vacation	—	—	437	1,189
Benefits paid	(31,439)	(22,599)	(6,481)	(6,036)
Benefit obligation as of end of year	$ 634,674	$ 527,004	$ 127,989	$ 108,249
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 481,502	$ 406,061	$ 29,732	$ 25,288
Actual return on plan assets	55,974	52,502	1,580	4,444
Employer contributions	32,000	44,263	—	—
Benefits paid	(30,165)	(21,324)	—	—
Fair value of plan assets as of end of year	$ 539,311	$ 481,502	$ 31,312	$ 29,732
Funded status	$ (95,363)	$ (45,502)	$ (96,677)	$ (78,517)
Unrecognized net actuarial loss	175,596	107,043	82,421	56,885
Unrecognized prior service cost	256	278	(10,379)	(707)
Prepaid (accrued) benefit cost	80,489	61,819	(24,635)	(22,339)
Additional liability	(175,852)	(107,321)	(72,042)	(56,178)
Accrued benefit liability	$ (95,363)	$ (45,502)	$ (96,677)	$ (78,517)
Accumulated pension benefit obligation	$ 551,615	$ 464,432	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 58,276	$ 52,384
For fully eligible employees			$ 31,843	$ 24,320
For other participants			$ 37,870	$ 31,545

	Pension Benefits		Other Post-retirement Benefits	
	2014	2013	2014	2013
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost	$ 166	$ 180	$ (6,747)	$ (7,472)
Unrecognized net actuarial loss	114,138	69,578	53,574	43,988
Total	114,304	69,758	46,827	36,516
Less regulatory asset	(106,484)	(64,925)	(46,759)	(37,116)
Accumulated other comprehensive loss (income) for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 7,820	$ 4,833	$ 68	$ (600)

	Pension Benefits		Other Post-retirement Benefits	
	2014	2013	2014	2013
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	4.21%	5.10%	4.16%	5.02%
Discount rate for annual expense	5.10%	4.15%	5.02%	4.15%
Expected long-term return on plan assets	6.60%	6.60%	6.40%	6.35%
Rate of compensation increase	4.87%	4.96%		
Medical cost trend pre-age 65 – initial			7.00%	7.00%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2021	2020
Medical cost trend post-age 65 – initial			7.00%	7.50%
Medical cost trend post-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2022	2021

	Pension Benefits			Other Post-retirement Benefits		
	2014	2013	2012	2014	2013	2012
Components of net periodic benefit cost:						
Service cost	$ 15,757	$ 19,045	$ 15,551	$ 1,844	$ 4,144	$ 2,804
Interest cost	26,224	23,896	24,349	5,226	5,216	5,056
Expected return on plan assets	(32,131)	(27,671)	(23,810)	(1,903)	(1,606)	(1,471)
Transition obligation recognition	—	—	—	—	—	505
Amortization of prior service cost	22	319	346	(1,116)	(149)	(149)
Net loss recognition	4,731	13,199	11,637	4,289	5,674	5,020
Net periodic benefit cost	$ 14,603	$ 28,788	$ 28,073	$ 8,340	$ 13,279	$ 11,765

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 in mutual funds, trusts and partnerships that hold marketable debt and equity securities, real estate, absolute return 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 and also investment ranges for each asset class. The target investment allocation percentages are typically the midpoint of the established range. The target investment allocation percentages by asset classes are indicated in the table below:

	2014	2013
Equity securities	27%	47%
Debt securities	58%	31%
Real estate	6%	6%
Absolute return	9%	12%
Other	—%	4%

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 reported last 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, 2014 and 2013.

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2014 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 3,138	$ —	$ 3,138
Fixed income securities:				
U.S. government issues	19,681	—	—	19,681
Corporate issues	104,959	—	—	104,959
International issues	19,935	—	—	19,935
Municipal issues	2,762	7,788	—	10,550
Mutual funds:				
Fixed income securities	157,415	8	—	157,423
U.S. equity securities	103,203	—	—	103,203
International equity securities	40,838	—	—	40,838
Absolute return (1)	15,334	—	—	15,334
Common/collective trusts:				
Real estate	—	—	21,303	21,303
Partnership/closely held investments:				
Absolute return (1)	—	—	36,114	36,114
Private equity funds (3)	—	—	73	73
Real estate	—	—	6,760	6,760
Total	$ 464,127	$ 10,934	$ 64,250	$ 539,311

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2013 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Mutual funds:				
Fixed income securities	$ 86,481	$ 310	$ —	$ 86,791
U.S. equity securities	152,831	—	—	152,831
International equity securities	85,942	—	—	85,942
Absolute return (1)	23,599	—	—	23,599
Common/collective trusts:				
Fixed income securities	—	55,872	—	55,872
Real estate	—	—	19,735	19,735
Partnership/closely held investments:				
Absolute return (1)	—	—	34,151	34,151
Private equity funds (3)	—	—	377	377
Commodities (2)	—	18,331	—	18,331
Real estate	—	—	3,873	3,873
Total	$ 348,853	$ 74,513	$ 58,136	$ 481,502

(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) This investment is in derivatives linked to commodity indices to gain exposure to the commodity markets. These positions are fully collateralized 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, 2014 (dollars in thousands):

	Common/collective trusts	Partnership/closely held investments		
	Real estate	Absolute return	Private equity funds	Real estate
Balance, as of January 1, 2014	$ 19,735	$ 34,151	$ 377	$ 3,873
Realized gains	24	—	—	595
Unrealized gains (losses)	1,097	1,963	(304)	(644)
Purchases, net	447	—	—	2,936
Balance, as of December 31, 2014	$ 21,303	$ 36,114	$ 73	$ 6,760

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, 2013 (dollars in thousands):

	Common/collective trusts	Partnership/closely held investments		
	Real estate	Absolute return	Private equity funds	Real estate
Balance, as of January 1, 2013	$ 17,596	$ 17,755	$ 660	$ —
Realized gains (losses)	—	—	(323)	—
Unrealized gains (losses)	2,139	2,396	345	113
Purchases (sales), net	—	14,000	(305)	3,760
Balance, as of December 31, 2013	$ 19,735	$ 34,151	$ 377	$ 3,873

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 60 percent equity securities and 40 percent debt securities in both 2014 and 2013.

The market-related value of other postretirement plan assets was determined as of December 31, 2014 and 2013.

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2014 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 3	$ —	$ 3
Mutual funds:				
Fixed income securities	11,968	—	—	11,968
U.S. equity securities	13,210	—	—	13,210
International equity securities	6,131	—	—	6,131
Total	$ 31,309	$ 3	$ —	$ 31,312

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2013 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 4	$ —	$ 4
Mutual funds:				
Fixed income securities	11,645	—	—	11,645
U.S. equity securities	11,831	—	—	11,831
International equity securities	6,252	—	—	6,252
Total	$ 29,728	$ 4	$ —	$ 29,732

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, 2014 by $5.2 million and the service and interest cost by $0.4 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, 2014 by $4.1 million and the service and interest cost by $0.3 million.

401(k) Plans and Executive Deferral Plan

Avista Utilities and METALfx 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):

	2014	2013	2012
Employer 401(k) matching contributions	$ 6,862	$ 6,279	$ 5,931

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):

	2014	2013
Deferred compensation assets and liabilities	$ 8,677	$ 9,170

AEL&P

Union Employees

Pension benefits for all union employees of AEL&P are provided through the Alaska Electrical Pension Fund Retirement Plan, a multiemployer plan to which AEL&P pays a defined contribution amount per union employee pursuant to a collective bargaining agreement with the IBEW.

AEL&P also participates in a multiemployer plan that provides substantially all union workers with health care and other welfare benefits during their working lives and after retirement. AEL&P pays a defined contribution amount per union employee pursuant to a collective bargaining agreement with the IBEW.

Non-Union Employees

AEL&P has a defined contribution money purchase pension plan covering all employees of AEL&P that are not covered by a collective bargaining agreement. Contributions to the plan are made based on a percentage of each employee's compensation.

AEL&P also has a noncontributory 401(k) savings plan, which covers substantially all nonunion employees who have completed 1,000 hours of service during a 12-month period. Employees who elect to participate may contribute up to the Internal Revenue Service's maximum amount.

The pension and other postretirement plans described above for AEL&P are not significant to Avista Corp.

NOTE 11. ACCOUNTING FOR INCOME TAXES

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

	2014	2013	2012
Current income tax expense (benefit)	$ (67,059)	$ 37,743	$ 18,710
Deferred income tax expense	139,299	20,271	21,054
Total income tax expense	$ 72,240	$ 58,014	$ 39,764

A reconciliation of federal income taxes derived from statutory federal tax rates (35 percent in 2014, 2013 and 2012) 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):

	2014	2013	2012
Federal income taxes at statutory rates	$ 67,237	$ 56,821	$ 40,798
Increase (decrease) in tax resulting from:			
Tax effect of regulatory treatment of utility plant differences	4,008	3,532	2,432
State income tax expense	506	1,553	863
Settlement of prior year tax returns and adjustment of tax reserves	1,104	(1,104)	(2,198)
Manufacturing deduction	(169)	(2,033)	(1,100)
Other	(446)	(755)	(1,031)
Total income tax expense	$ 72,240	$ 58,014	$ 39,764

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):

	2014	2013
Deferred income tax assets:		
Allowance for doubtful accounts	$ 1,714	$ 12,202
Reserves not currently deductible	2,889	6,322
Net operating loss from subsidiary acquisition	538	9,258
Deferred compensation	3,117	3,676
Unfunded benefit obligation	72,108	42,230
Utility energy commodity derivatives	19,493	13,303
Power and natural gas deferrals	3,811	9,226
Tax credits	16,662	11,365
Interest rate swaps	8,934	—
Other	1,776	29,133
Total deferred income tax assets	131,042	136,715
Deferred income tax liabilities:		
Intangible assets from subsidiary acquisition	—	4,271
Differences between book and tax basis of utility plant	690,597	521,238
Regulatory asset for pensions and other postretirement benefits	82,515	54,945
Power exchange contract	—	5,484
Utility energy commodity derivatives	19,495	13,305
Loss on reacquired debt	5,128	5,732
Interest rate swaps	—	15,097
Settlement with Coeur d’Alene Tribe	12,751	13,190
Other	16,104	14,008
Total deferred income tax liabilities	826,590	647,270
Net deferred income tax liability	$ 695,548	$ 510,555
Consolidated balance sheet classification of net deferred income taxes:		
Current deferred income tax asset	$ 14,794	$ 24,788
Long-term deferred income tax liability	710,342	535,343
Net deferred income tax liability	$ 695,548	$ 510,555

As of December 31, 2014, the Company had $11.3 million of state tax credit carryforwards. State tax credits expire from 2019 to 2028. 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 2011 and all issues were resolved related to these years. The IRS has not completed an examination of the Company’s 2012 and 2013 federal income tax returns. The Company believes that any open tax years for federal or state income taxes will not result in adjustments that would be significant to the consolidated financial statements.

The Company did not incur any penalties on income tax positions in 2014, 2013 or 2012. 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):

	2014	2013
Regulatory assets for deferred income taxes	$ 100,412	$ 71,421
Regulatory liabilities for deferred income taxes	14,534	9,203

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 2042. 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):

	2014	2013	2012
Utility power resources	$ 556,915	$ 524,810	$ 523,416

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):

	2015	2016	2017	2018	2019	Thereafter	Total
Power resources	$ 277,474	$ 209,255	$ 144,424	$ 132,897	$ 125,332	$ 860,731	$ 1,750,113
Natural gas resources	82,884	56,504	57,379	52,936	49,304	455,975	754,982
Total	$ 360,358	$ 265,759	$ 201,803	$ 185,833	$ 174,636	$ 1,316,706	$ 2,505,095

These energy purchase contracts were entered into as part of Avista Utilities' obligation to serve its retail electric and natural gas customers' energy requirements, including contracts entered into for resource optimization. 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.

The above future contractual commitments for power resources include fixed contractual amounts related to the Company's 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 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. The contractual amounts included above consist of Avista Utilities' share of existing debt service cost and its proportionate share of the variable operating expenses of these projects. The minimum amounts payable under these contracts are based in part on the proportionate share of the debt service requirements of the PUD's revenue bonds for which the Company is indirectly responsible. The Company's total future debt service obligation associated with the revenue bonds outstanding at December 31, 2014 (principal and interest) was $59.4 million.

In addition, Avista Utilities has operating agreements, settlements and other contractual obligations related to its generating facilities and transmission and distribution services. 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 under these agreements (dollars in thousands):

	2015	2016	2017	2018	2019	Thereafter	Total
Contractual obligations	$ 29,133	$ 35,692	$ 28,189	$ 25,659	$ 28,969	$ 193,734	$ 341,376

NOTE 13. COMMITTED LINES OF CREDIT

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. In April 2014, the Company amended this committed line of credit agreement to extend the expiration date to April 2019. The amendment also provides the Company the option to request an extension for an additional one or two years beyond April 2019, provided, 1) there are no default events prior to the requested extension, and 2) the remaining term of agreement, including the requested extension period, does not exceed five years. The amendment did not change the amount of the committed line of credit.

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

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of “consolidated total debt” to “consolidated total capitalization” of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2014, 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):

	2014	2013
Balance outstanding at end of period	$ 105,000	$ 171,000
Letters of credit outstanding at end of period	$ 32,579	$ 27,434
Average interest rate at end of period	0.93%	1.02%

As of December 31, 2014 and 2013, the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Consolidated Balance Sheet.

AEL&P

In November 2014, AEL&P entered into a committed line of credit in the amount of $25.0 million with an expiration date of November 2019. As of December 31, 2014, there were no borrowings or letters of credit outstanding under this committed line of credit.

The committed line of credit is secured by non-transferable first mortgage bonds of AEL&P issued to the agent bank that would only become due and payable in the event, and then only to the extent, that AEL&P 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 at AEL&P” to “consolidated total capitalization at AEL&P,” including the impact of the Snettisham bonds to be greater than 67.5 percent at any time. As of December 31, 2014, the Company was in compliance with this covenant.

Ecova

Ecova had a $125.0 million committed line of credit agreement with various financial institutions that had an expiration date of July 2017. The credit agreement was secured by all of Ecova's assets excluding investments and funds held for clients. Ecova was disposed of as of June 30, 2014 and the balance outstanding under this credit agreement was paid in full as part of the sales transaction. As of December 31, 2014, this committed line of credit is no longer on the balance sheet.

The balance outstanding and interest rate of borrowings under Ecova’s credit agreements were as follows as of December 31, 2013 (dollars in thousands):

	2013
Balance outstanding at end of period	$ 46,000
Average interest rate at end of period	2.17%

As of December 31, 2013 the borrowings outstanding were classified as 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	2014	2013
Avista Corp. Secured Long-Term Debt				
2016	First Mortgage Bonds	0.84%	$ 90,000	$ 90,000
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 (1)	(1)	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
2044	First Mortgage Bonds (2)	4.11%	60,000	—
2047	First Mortgage Bonds	4.23%	80,000	80,000
	Total Avista Corp. secured long-term debt		1,436,700	1,376,700
Alaska Electric Light and Power Company Secured Long-Term Debt				
2044	First Mortgage Bonds (3)	4.54%	75,000	—
	Total secured long-term debt		1,511,700	1,376,700
Alaska Energy and Resources Company Unsecured Long-Term Debt				
2019	Unsecured Term Loan (4)	3.85%	15,000	—
	Total secured and unsecured long-term debt		1,526,700	1,376,700
	Other long-term debt and capital leases		74,149	4,630
	Settled interest rate swaps (5)		(17,541)	(23,560)
	Unamortized debt discount		(1,122)	(1,287)
	Total		1,582,186	1,356,483
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Current portion of long-term debt		(6,424)	(358)
	Total long-term debt		$ 1,492,062	$ 1,272,425

(1) In December 2010, $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due in 2032 and 2034, respectively, which had been held by Avista Corp. since 2008 and 2009, respectively, were refunded by new bond issues (Series 2010A and 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, 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 Sheets.

(2) In December 2014, Avista Corp. issued $60.0 million of first mortgage bonds to three institutional investors in a private placement transaction. The first mortgage bonds bear an interest rate of 4.11 percent and mature in 2044. The total net proceeds from the sale of the new bonds were used to repay a portion of the borrowings outstanding under the Company's $400.0 million committed line of credit and for general corporate purposes.

(3) In September 2014, AEL&P issued $75.0 million of 4.54 percent first mortgage bonds due in 2044 to two institutional investors in the private placement market. The first mortgage bonds were issued under and in accordance with the AEL&P Mortgage and Deed of Trust, dated as of July 1, 2014.

(4) In December 2014, AERC issued a $15.0 million unsecured term loan note due in 2019 to a national cooperative bank. The term note bears an interest rate of 3.85 percent.

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

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

	2015	2016	2017	2018	2019	Thereafter	Total
Debt maturities	$ —	$ 90,000	$ —	$ 272,500	$ 105,000	$ 1,027,047	$ 1,494,547

Substantially all Avista Utilities' and AEL&P's owned properties are subject to the lien of their respective mortgage indentures. Under the Mortgages and Deeds of Trust (Mortgages) securing their first mortgage bonds (including secured medium-term notes), Avista Utilities and AEL&P may each issue additional first mortgage bonds under their specific mortgage 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 at each entity which have not previously been made the basis of any application under the Mortgages, or 2) an equal principal amount of retired first mortgage bonds at each entity which have not previously been made the basis of any application under the Mortgages, or 3) deposit of cash. However, Avista Utilities and AEL&P may not individually issue any additional first mortgage bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the particular entity issuing the bonds has “net earnings” (as defined in the Mortgages) for any period of 12 consecutive calendar months out of the preceding 18 calendar months that 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, 2014, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.0 billion in aggregate principal amount of additional first mortgage bonds at Avista Utilities and $3.5 million at AEL&P.

See Note 13 for information regarding first mortgage bonds issued to secure the Company’s obligations under its committed line of credit agreement.

Snettisham Capital Lease Obligation

Included in long-term capital leases above is a power purchase agreement between AEL&P and AIDEA, an agency of the State of Alaska, under which AEL&P has a take-or-pay obligation, expiring in December 2038, to purchase all the output of the 78 MW Snettisham hydroelectric project. For accounting purposes, this power purchase agreement is treated as a capital lease. As of December 31, 2014, the capital lease obligation was $70.0 million (which is equal to the amount of AIDEA's revenue bonds outstanding) and the capital lease asset was $71.0 million (included in utility plant in service on the Consolidated Balance Sheet) and accumulated amortization was $1.8 million. For 2014 interest on the capital lease obligation was $1.9 million and amortization of the capital lease asset was $1.8 million. These amounts were included in utility resource costs in the Consolidated Statements of Income.

AIDEA issued $100.0 million in revenue bonds in 1998 to finance its acquisition of the project and the payments by AEL&P are designed to be more than sufficient to enable the AIDEA to pay the principal and interest amount of its revenue bonds, bearing interest at rates ranging from 4.9 percent to 6.0 percent and maturing in January 2034. AEL&P will make its last bond payment to AIDEA in December 2033. The payments by AEL&P under the agreement are unconditional, notwithstanding any suspension, reduction or curtailment of the operation of the project. The bonds are payable solely out of AIDEA's receipts under the agreement. AEL&P is also obligated to operate, maintain and insure the project. AEL&P's payments for power under the agreement are approximately $10.6 million per year, while debt service on the bonds is approximately $5.9 million per year, which are included in the $10.6 million total costs of power.

Snettisham Electric Company, a non-operating subsidiary of AERC, has the option to purchase the Snettisham project at any time for the principal amount of the bonds outstanding at that time.

While the power purchase agreement is treated as a capital lease for accounting purposes, for ratemaking purposes, this agreement is treated as an operating lease with a constant level of annual rental expense (straight line expense). Because of this regulatory treatment, any difference between the operating lease expense for ratemaking purposes and the expenses recognized under capital lease treatment (interest and depreciation of the capital lease asset) is recorded as a regulatory asset and amortized during the later years of the lease when the capital lease expense is less than the operating lease expense included in base rates.

The Company evaluated this agreement to determine if it has a variable interest which must be consolidated. Based on this evaluation, AIDEA will not be consolidated under ASC 810 "Consolidation" because AIDEA is a government agency and ASC 810 has a specific scope exception which does not allow for the consolidation of government organizations.

The following table details future capital lease obligations, including interest, under the Snettisham PPA (dollars in thousands):

	2015	2016	2017	2018	2019	Thereafter	Total
Principal	$ 2,230	$ 2,350	$ 2,480	$ 2,615	$ 2,755	$ 57,525	$ 69,955
Interest	3,690	3,567	3,438	3,305	3,165	25,364	42,529
Total	$ 5,920	$ 5,917	$ 5,918	$ 5,920	$ 5,920	$ 82,889	$ 112,484

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. As of December 31, 2014, the entire remaining portion of the nonrecourse debt of $1.4 million was included in current liabilities due to its maturity in January 2015.

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:

	2014	2013	2012
Low distribution rate	1.10%	1.11%	1.19%
High distribution rate	1.11%	1.19%	1.40%
Distribution rate at the end of the year	1.11%	1.11%	1.19%

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. 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 and material capital leases), nonrecourse long-term debt and long-term debt to affiliated trusts are reported at carrying value on the Consolidated Balance Sheets.

The fair value hierarchy prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement).

The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 – Pricing inputs include significant inputs that are generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of Avista Corp.'s nonperformance risk on its liabilities.

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

	2014		2013	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 951,000	$ 1,118,972	$ 951,000	$ 1,054,512
Long-term debt (Level 3)	492,000	527,663	342,000	329,581
Snettisham capital lease obligation (Level 3)	69,955	79,290	—	—
Nonrecourse long-term debt (Level 3)	1,431	1,440	17,838	18,636
Long-term debt to affiliated trusts (Level 3)	51,547	38,582	51,547	37,114

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of par values of 74.85 to 131.21, where a par value of 100.00 represents the carrying value recorded on the Consolidated Balance Sheets. 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) and the unique nature of the Snettisham capital lease obligation, the estimated fair value of these items was determined based on a discounted cash flow model using available market information. The market information for the nonrecourse long-term debt consisted of third party broker quotes for risk premiums for Avista Corp., along with risk free interest rates obtained from the Federal Reserve, which were then used to discount the future cash flows to present value. The Snettisham capital lease obligation was discounted to present value using the Moody's Aaa Corporate discount rate as published by the Federal Reserve on December 31, 2014.

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, 2014 and 2013 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, 2014					
Assets:					
Energy commodity derivatives	$ —	$ 96,729	$ —	$ (95,204)	$ 1,525
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	1,349	(1,349)	—
Foreign currency derivatives	—	1	—	(1)	—
Interest rate swaps	—	966	—	(506)	460
Funds held in trust account of Spokane Energy	1,600	—	—	—	1,600
Deferred compensation assets:					
Fixed income securities (2)	1,793	—	—	—	1,793
Equity securities (2)	6,074	—	—	—	6,074
Total	$ 9,467	$ 97,696	$ 1,349	$ (97,060)	$ 11,452
Liabilities:					
Energy commodity derivatives	$ —	$ 127,094	$ —	$ (110,714)	$ 16,380
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	1,384	(1,349)	35
Power exchange agreement	—	—	23,299	—	23,299
Power option agreement	—	—	424	—	424
Interest rate swaps	—	77,568	—	(29,386)	48,182
Foreign currency derivatives	—	21	—	(1)	20
Total	$ —	$ 204,683	$ 25,107	$ (141,450)	$ 88,340

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2013					
Assets:					
Energy commodity derivatives	$ —	$ 55,243	$ —	$ (51,367)	$ 3,876
Level 3 energy commodity derivatives:					
Power exchange agreement	—	—	339	(339)	—
Foreign currency derivatives	—	7	—	(6)	1
Interest rate swaps	—	33,543	—	—	33,543
Investments and funds held for clients:					
Money market funds	11,180	—	—	—	11,180
Securities available for sale:					
U.S. government agency	—	61,078	—	—	61,078
Municipal	—	3,518	—	—	3,518
Corporate fixed income – financial	—	3,000	—	—	3,000
Corporate fixed income – industrial	—	765	—	—	765
Certificate of deposits	—	1,000	—	—	1,000
Funds held in trust account of Spokane Energy	1,600	—	—	—	1,600
Deferred compensation assets:					
Fixed income securities (2)	1,960	—	—	—	1,960
Equity securities (2)	6,470	—	—	—	6,470
Total	$ 21,210	$ 158,154	$ 339	$ (51,712)	$ 127,991
Liabilities:					
Energy commodity derivatives	$ —	$ 72,895	$ —	$ (60,099)	$ 12,796
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	1,219	—	1,219
Power exchange agreement	—	—	14,780	(339)	14,441
Power option agreement	—	—	775	—	775
Foreign currency derivatives	—	6	—	(6)	—
Total	$ —	$ 72,901	$ 16,774	$ (60,444)	$ 29,231

(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.

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, 2014 and $0.7 million as of December 31, 2013.

Level 3 Fair Value

For the power exchange agreement, 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 the power commodity option agreement, 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 2015, and 3) volatility rates for periods beyond December 2017. 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 the natural gas commodity exchange agreement, 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, 2014 (dollars in thousands):

	Fair Value (Net) at December 31, 2014	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (23,299)	Surrogate facility pricing	O&M charges	$30.66-$55.56/MWh (1)
			Escalation factor	3% - 2015 to 2019
			Transaction volumes	184,077 - 397,116 MWhs
Power option agreement	(424)	Black-Scholes-Merton	Strike price	$41.20/MWh - 2015
				$64.09/MWh - 2019
			Delivery volumes	157,517 - 287,147 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreement	(35)	Internally derived weighted average cost of gas	Forward purchase prices	$2.32 - $2.57/mmBTU
			Forward sales prices	$2.56 - $3.53/mmBTU
			Purchase volumes	280,000 - 310,000 mmBTUs
			Sales volumes	279,990 - 365,118 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2014 were $42.90 per MWh. For ratemaking purposes the average O&M charges to be included for recovery in retail rates vary slightly between regulatory jurisdictions. The average O&M charges for the delivery year beginning in 2014 were $43.11 for Washington and $42.90 for Idaho.
(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.45 for 2015 to 0.21 in December 2017.

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, significant inputs and 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 Agreement	Power Exchange Agreement	Power Option Agreement	Total
Year ended December 31, 2014:				
Balance as of January 1, 2014	$ (1,219)	$ (14,441)	$ (775)	$ (16,435)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	3,873	(10,002)	351	(5,778)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(2,689)	1,144	—	(1,545)
Transfers to/from other categories	—	—	—	—
Ending balance as of December 31, 2014	$ (35)	$ (23,299)	$ (424)	$ (23,758)
Year ended December 31, 2013:				
Balance as of January 1, 2013	$ (2,379)	$ (18,692)	$ (1,480)	$ (22,551)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	2,298	1,017	705	4,020
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(1,138)	3,234	—	2,096
Transfers from other categories	—	—	—	—
Ending balance as of December 31, 2013	$ (1,219)	$ (14,441)	$ (775)	$ (16,435)
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 from other categories	—	—	—	—
Ending balance as of December 31, 2012	$ (2,379)	$ (18,692)	$ (1,480)	$ (22,551)

(1) The UTC and the IPUC issued accounting orders authorizing Avista Corp. 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 delivery. The orders provide for Avista Corp. 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 delivery, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases.

NOTE 17. 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 2014, 2013 and 2012 are disclosed in the Consolidated Statements of Equity and Redeemable Noncontrolling Interests.

The payment of dividends on common stock could be limited by:

- certain covenants applicable to preferred stock (when outstanding) contained in the Company's Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements,
- the hydroelectric licensing requirements of section 10(d) of the FPA (see Note 1), and.
- certain requirements under the OPUC approval of the AERC acquisition. After the initial year, the OPUC does not permit one-time or special dividends from AERC to Avista Corp. and does not permit Avista Utilities' total equity to total capitalization to be less than 40 percent, without approval from the OPUC. However, the OPUC approval does allow for regular distributions of AERC earnings to Avista Corp. as long as AERC remains sufficiently capitalized and insured.

The Company declared the following dividends for the year ended December 31:

	2014	2013	2012
Dividends paid per common share	$ 1.27	$ 1.22	$ 1.16

Under the covenant applicable to the Company's committed line of credit agreement, which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 65 percent at any time, the amount of retained earnings available for dividends at December 31, 2014 was limited to approximately $295.0 million.

Under the requirements of the OPUC approval of the AERC acquisition as outlined above, the amount available for dividends at December 31, 2014 was limited to approximately $145.0 million.

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. There were no shares issued under these agreements during 2014 and 2013 and as of December 31, 2014, the Company had 1,795,199 shares available to be issued under these agreements.

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

	2014	2013	2012
Shares issued under sales agency agreement	—	—	931,191

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2014 and 2013.

Stock Repurchase Programs

On June 13, 2014, Avista Corp.'s Board of Directors approved a program to repurchase up to 4 million shares of the Company's outstanding common stock, assuming the closure of the Ecova transaction (2014 program). Repurchases of common stock under this program commenced on July 7, 2014 and the program expired on December 31, 2014. Repurchases were made in the open market or in privately negotiated transactions. Through December 31, 2014, the Company repurchased 2,529,615 shares at a total cost of $79.9 million and an average cost of $31.57 per share. The Company did not make any repurchases under this program subsequent to October 2014. All repurchased shares reverted to the status of authorized but unissued shares.

On December 16, 2014, Avista Corp.'s Board of Directors approved the repurchase of up to 800,000 shares of the Company's outstanding common stock, commencing on January 2, 2015, and continuing through March 31, 2015 (first quarter 2015 program). The number of shares repurchased through the first quarter 2015 program is in addition to the number of shares repurchased under the 2014 program, which expired on December 31, 2014. The parameters of the first quarter 2015 program are consistent with the parameters of the 2014 program. All repurchased shares, if any, will revert to the status of authorized but unissued shares.

NOTE 18. 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 Corp. shareholders for the years ended December 31 (in thousands, except per share amounts):

	2014	2013	2012
Numerator:			
Net income from continuing operations attributable to Avista Corp. shareholders	$ 119,817	$ 104,273	$ 76,719
Net income from discontinued operations attributable to Avista Corp. shareholders	72,224	6,804	1,491
Subsidiary earnings adjustment for dilutive securities (discontinued operations)	5	(229)	(38)
Adjusted net income from discontinued operations attributable to Avista Corp. shareholders for computation of diluted earnings per common share	$ 72,229	$ 6,575	$ 1,453
Denominator:			
Weighted-average number of common shares outstanding-basic	61,632	59,960	59,028
Effect of dilutive securities:			
Performance and restricted stock awards	255	37	162
Stock options	—	—	11
Weighted-average number of common shares outstanding-diluted	61,887	59,997	59,201
Earnings per common share attributable to Avista Corp. shareholders, basic:			
Earnings per common share from continuing operations	$ 1.94	$ 1.74	$ 1.30
Earnings per common share from discontinued operations	$ 1.18	$ 0.11	$ 0.02
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 3.12	$ 1.85	$ 1.32
Earnings per common share attributable to Avista Corp. shareholders, diluted:			
Earnings per common share from continuing operations	$ 1.93	$ 1.74	$ 1.30
Earnings per common share from discontinued operations	$ 1.17	$ 0.11	$ 0.02
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 3.10	$ 1.85	$ 1.32

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 19. STOCK COMPENSATION PLANS

Avista Corp.

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, 2014, 0.4 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, 2014, 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):

	2014	2013	2012
Stock-based compensation expense	$ 6,007	$ 5,037	$ 4,549
Income tax benefits	2,102	1,763	1,592

Stock Options

There are no longer any stock options outstanding as of December 31, 2014 and the Company does not have any plans to issue additional stock options in the near future.

The following summarizes stock options activity under the 1998 Plan and the 2000 Plan for the years ended December 31, 2013 and 2012:

	2013	2012
Number of shares under stock options:		
Options outstanding at beginning of year	3,000	92,499
Options granted	—	—
Options exercised	(3,000)	(89,499)
Options canceled	—	—
Options outstanding and exercisable at end of year	—	3,000
Weighted average exercise price:		
Options exercised	$ 12.41	$ 10.63
Options canceled	$ —	$ —
Options outstanding and exercisable at end of year	$ —	$ 12.41
Cash received from options exercised (in thousands)	$ 37	$ 951
Intrinsic value of options exercised (in thousands)	$ 40	$ 1,349
Intrinsic value of options outstanding (in thousands)	$ —	$ 35

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, 2014 was 0.7 years.

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

	2014	2013	2012
Unvested shares at beginning of year	104,416	117,118	93,482
Shares granted	62,075	44,556	70,281
Shares canceled	(1,550)	(1,802)	(790)
Shares vested	(52,899)	(55,456)	(45,855)
Unvested shares at end of year	112,042	104,416	117,118
Weighted average fair value at grant date	$ 28.37	$ 26.04	$ 25.83
Unrecognized compensation expense at end of year (in thousands)	$ 1,349	$ 1,199	$ 1,428
Intrinsic value, unvested shares at end of year (in thousands)	$ 3,961	$ 2,943	$ 2,824
Intrinsic value, shares vested during the year (in thousands)	$ 1,473	$ 1,363	$ 1,173

Performance and Market-Based Awards

The Company has two types of awards that fall under this category, Total Shareholder Return (TSR) awards, which are market-based awards and Cumulative Earnings Per Share (CEPS) awards, which are performance awards. Both types of 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. The method of settlement is at the discretion of the Company and historically the Company has settled these awards through issuance of Avista Corp. common stock and intends to continue this practice. Both types of awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific market or performance conditions. Based on the level of attainment of the market or performance conditions, the amount of cash paid or common stock issued will range from 0 to 200 percent of the initial awards granted. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest and have met the market and performance conditions.

Both types of awards entitle the grantee to shares of Avista Corp. common stock or cash payable once the service condition is satisfied and provided that the market or performance conditions are achieved. All TSR awards granted have two conditions, the service condition of three years and a market-based condition, which is the Company's TSR performance over a three-year period as compared against other utilities. CEPS awards began in 2014 and they also have two conditions, the service condition of three years and a performance condition, which is the Company's CEPS performance over a three-year period. CEPS is a performance condition based solely on internal metrics and it is used to determine whether an award vests or not. The level of payout for both the TSR and CEPS awards is based on the level of attainment of the market and performance conditions, respectively.

TSR awards 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. CEPS awards are equity awards with a performance condition based solely on internal Company metrics; therefore, compensation cost for these awards is recognized over the requisite service period, provided that the requisite service period is rendered. However, if the CEPS performance metric is not met, all compensation cost for these awards is reversed as these awards are not considered vested.

The Company measures (at the grant date) the estimated fair value of the shares awarded. The fair value of each TSR award was estimated on the date of grant using a statistical model that incorporates the probability of meeting the market 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 TSR awards 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 estimated fair value of the equity component of CEPS awards was estimated on the date of grant as the share price of Avista Corp. common stock on the date of grant, less the net present value of the estimated dividends over the three-year period. The combined fair value of the equity and dividend components of CEPS awards is equal to the share price of Avista Corp. common stock on the date of grant.

The following summarizes the weighted average assumptions used to determine the fair value of TSR and CEPS awards and related compensation expense as well as the resulting estimated fair value of awards granted:

	2014	2013	2012
TSR assumptions			
Risk-free interest rate	0.7%	0.4%	0.3%
Expected life, in years	3	3	3
Expected volatility	17.9%	19.1%	22.7%
Dividend yield	4.5%	4.6%	4.5%
Weighted average grant date fair value (per share)	$ 24.64	$ 23.30	$ 26.06
CEPS assumptions			
Weighted average share price on date of grant	$ 28.09	$ —	$ —
Annual dividends per share	1.22	—	—
Risk-free interest rate	0.7%	—%	—%
Weighted average grant date fair value of equity component (per share)	$ 24.48	$ —	$ —

The weighted average grant date fair value above for TSR awards includes both the equity component and dividend equivalent rights.

The following summarizes TSR and CEPS share activity:

	2014	2013	2012
TSR Awards			
Opening balance of unvested TSR shares	344,684	359,700	351,345
TSR shares granted	117,550	175,000	181,000
TSR shares canceled	(6,816)	(13,298)	(4,544)
TSR shares vested	(167,584)	(176,718)	(168,101)
Ending balance of unvested TSR shares	287,834	344,684	359,700
Intrinsic value of unvested performance shares (in thousands)	$ 10,175	$ 9,717	$ 8,672
Unrecognized compensation expense (in thousands)	$ 2,833	$ 3,651	$ 3,800
CEPS Awards			
Opening balance of unvested CEPS shares	—	—	—
CEPS shares granted	59,025	—	—
CEPS shares canceled	(1,008)	—	—
CEPS shares vested	—	—	—
Ending balance of unvested CEPS shares	58,017	—	—
Intrinsic value of unvested performance shares (in thousands)	$ 2,051	$ —	$ —
Unrecognized compensation expense (in thousands)	$ 1,577	$ —	$ —

The weighted average remaining vesting period for the Company's TSR shares outstanding as of December 31, 2014 was 1.4 years. The weighted average remaining vesting period for the Company's CEPS shares outstanding as of December 31, 2014 was 2 years. Unrecognized compensation expense as of December 31, 2014 includes only the amount attributable to the equity portion of the awards and will be recognized during 2015 and 2016.

The following summarizes the impact of the market condition on the TSR shares that met the service vesting condition (no CEPS awards vested in 2014):

	2014	2013	2012
TSR shares vested based on service condition	167,584	176,718	168,101
Impact of market condition on shares vested	(70,385)	(176,718)	(168,101)
Shares of common stock earned	97,199	—	—
Intrinsic value of common stock earned (in thousands)	$ 3,436	$ —	$ —

Shares earned under this plan are distributed to participants in the quarter following vesting.

Outstanding TSR and CEPS share awards include a dividend component that is paid in cash. This component of the 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, the change in the value of the Company's common stock relative to an external benchmark (TSR awards only) and the amount of CEPS earned to-date compared to estimated CEPS over the performance period (CEPS awards only). Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2014 and 2013, the Company had recognized cumulative compensation expense and a liability of $1.3 million and $0.9 million, respectively, related to the dividend component on the outstanding and unvested share grants.

NOTE 20. 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' or AEL&P's 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) 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). 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 energy markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX)(Bidding Investigation). Appeals of the FERC’s decisions are pending before the United States Court of Appeals for the Ninth Circuit (Ninth Circuit).

On March 7, 2014, Avista Utilities and Avista Energy filed at FERC a settlement with Pacific Gas & Electric (PG&E), Southern California Edison, San Diego Gas & Electric, the California Attorney General (AG), the California Department of Water Resources (CERS), and the California Public Utilities Commission (together, the “California Parties”) that resolves both the Trading Investigation and the Bidding Investigation. The settlement was approved by the FERC and is final so there is no longer any potential liability.

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). Petitions for review of the FERC’s decisions are still pending in the Ninth Circuit. In August 2006, the Ninth Circuit remanded to the FERC its decision not to consider a Federal Power Act (FPA) section 309 remedy for tariff violations prior to October 2, 2000. During the FERC hearing on the remand in 2012, the Presiding Administrative Law Judge (ALJ) issued a partial initial decision granting Avista Utilities' motion for summary disposition. On November 2, 2012, the FERC issued an order affirming the partial initial decision and dismissing Avista Utilities from the proceeding. On February 15, 2013, the ALJ issued an Initial Decision that may have subjected Avista Energy to additional refund liability.

On March 7, 2014, Avista Utilities, Avista Energy and the California Parties filed a settlement at the FERC that fully resolved these matters. Because Avista Energy had not been paid for all of its sales during the Refund Period, substantial funds have been held in escrow accounts pending resolution of this proceeding. The settlement returned $15.0 million of Avista Energy’s receivable to Avista Energy, with the balance of the Avista Energy receivable flowing to the purchasers associated with the hourly transactions at issue. The settlement funds were received on June 23, 2014 and recorded as a reduction to other operating expenses within the non-utility operating expenses section of the Consolidated Statements of Income. There is no admission of wrongdoing on the part of the settling parties and no part of the refund payment by Avista Energy constitutes a fine or a penalty. The settlement resolves all claims for alleged overcharges in the California Refund Proceeding, and in the Pacific Northwest Refund Proceeding (for sales made to CERS). The settlement also includes settlement of the Trading Investigation, the Bidding Investigation and the California Attorney General Complaint (the "Lockyer Complaint"). The settlement was approved by the FERC and is final so there is no longer any potential liability.

California Attorney General Complaint (the “Lockyer Complaint”)

In May 2002, the FERC 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 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, which ultimately resulted in summary disposition at the FERC in favor of Avista Utilities and Avista Energy. The proceeding is now before the Ninth Circuit.

On March 7, 2014, Avista Utilities, Avista Energy and the California Parties filed a settlement at the FERC that resolves this matter. The settlement was approved by the FERC and is final so there is no longer any potential liability.

Pacific Northwest Refund Proceeding

In July 2001, the Federal Energy Regulatory Commission (“FERC” or “Commission”) 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 had failed to take into account new evidence of market manipulation 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 new evidence. The Ninth Circuit expressly declined to direct the FERC to grant refunds. On October 3, 2011, the FERC issued an Order on Remand. On April 5, 2013, the FERC issued an Order on Rehearing expanding the temporal scope of the proceeding to permit parties to submit evidence on transactions during the period from January 1, 2000 through and including June 20, 2001. The Order on Remand established an evidentiary, trial-type hearing before an ALJ, and reopened the record to permit parties to present evidence of unlawful market activity. The Order on Remand stated 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 would not be sufficient to establish a causal connection between a particular seller's alleged unlawful activities and the specific contract negotiations at issue. The hearing was conducted in August through October 2013. The City of Seattle, Washington (Seattle) and the California AG (on behalf of CERS) filed petitions for review of FERC’s Order on Remand in the 9th Circuit Court of Appeals, which petitions were stayed pending completion of the FERC proceeding.

On July 11, 2012 and March 28, 2013, Avista Energy and Avista Utilities filed settlements of all issues in this docket with regard to the claims made by the City of Tacoma and the California AG (on behalf of CERS). The FERC approved the settlements and they are final. The remaining direct claimant against Avista Utilities and Avista Energy in this proceeding is Seattle.

With regard to the Seattle claims, on March 28, 2014, the Presiding ALJ issued her Initial Decision finding that: 1) Seattle failed to demonstrate that either Avista Utilities or Avista Energy engaged in unlawful market activity and also failed to identify any specific contracts at issue; 2) Seattle failed to demonstrate that contracts with either Avista Utilities or Avista Energy imposed an excessive burden on consumers or seriously harmed the public interest; and that 3) Seattle failed to demonstrate that either Avista Utilities or Avista Energy engaged in any specific violations of substantive provisions of the Federal Power Act or any filed tariffs or rate schedules. Accordingly, the ALJ denied all of Seattle’s claims under both section 206 and section 309 of the Federal Power Act. Briefs on and opposing exceptions have been filed and the Initial Decision is pending before the FERC.

The 9th Circuit by Order dated February 17, 2015 issued on its own motion, lifted the stay of the 2013 interlocutory petitions for review of the FERC Order on Remand and established a briefing schedule for those petitions, including Seattle’s petition challenging the scope of the Remand Order. Any decision by the 9th Circuit adverse to the Company could only result in a further remand to FERC to conduct further proceedings, the scope of which cannot be predicted at this time. The Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

Sierra Club and Montana Environmental Information Center Complaint Against the Owners of Colstrip

On March 6, 2013, the Sierra Club and Montana Environmental Information Center (MEIC) (collectively "Plaintiffs"), filed a Complaint in the United States District Court for the District of Montana, Billings Division, against the Owners of the Colstrip Generating Project ("Colstrip"). Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The other Colstrip co-Owners are PPL Montana, Puget Sound Energy, Portland General Electric Company, NorthWestern Energy and PacifiCorp. The Complaint alleges certain violations of the Clean Air Act, including the New Source Review, Title V and opacity requirements. The Plaintiffs request that the Court grant injunctive and declaratory relief, impose civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require payment of Plaintiffs' costs of litigation and attorney fees.

On September 12, 2013, the Plaintiffs filed Plaintiffs’ First Motion for Partial Summary Judgment on the Applicable Method for Calculating Emission Increases from Modifications Made to Colstrip.

On September 27, 2013, the Plaintiffs filed an Amended Complaint. The Amended Complaint withdrew from the original Complaint fifteen claims related to seven pre-January 1, 2001 Colstrip maintenance projects, upgrade projects and work projects and claims alleging violations of Title V and opacity requirements. The Amended Complaint alleges certain violations of the Clean Air Act and the New Source Review and adds claims with respect to post-January 1, 2001 Colstrip projects. The Plaintiffs request that the Court grant injunctive and declaratory relief, order remediation of alleged environmental damage, impose civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require payment of Plaintiffs’ costs of litigation and attorney fees. The Colstrip Owners filed a Motion to Dismiss, seeking dismissal of all of Plaintiffs' claims contained in the Amended Complaint.

On May 22, 2014, the Magistrate Judge filed his Findings and Recommendations as to the motions and recommended that 1) the Colstrip Owners' Motion to Dismiss be granted as to the Plaintiffs' Best Available Control Technology claims and the injunctive relief sought regarding two of the claims, but denied the Motion in all other respects; and 2) the Plaintiffs' Motion for Partial Summary Judgment be denied. Plaintiffs' filed Objections to Findings and Recommendations of Magistrate Judge and the Colstrip Owners filed their response to Plaintiffs' objections.

On August 27, 2014, the Plaintiffs filed a Second Amended Complaint. The Second Amended Complaint withdraws from the Amended Complaint five claims and adds one new claim. The Second Amended Complaint alleges certain violations of the Clean Air Act and the New Source Review. The Plaintiffs request that the Court grant injunctive and declaratory relief, order remediation of alleged environmental damages, impose civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require payment of Plaintiffs' costs of litigation and attorney fees.

The Court has set the trial date for November 2015.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to uncertainties concerning this matter, Avista Corp. cannot estimate the outcome or determine whether it would have a material impact on the Company.

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 began implementing this plan in 2013, 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. On February 19, 2015, the Court dismissed the case as stipulated to by all parties.

During 2013, through a collaborative process with key stakeholders, a decision was reached to not move forward with a specific capital project to add oxygen to Lake Spokane. At the time of such decision, the Company had expended $1.3 million on the discontinued project. The Company obtained regulatory Orders from the UTC and IPUC during the second half of 2013, allowing regulatory treatment of the costs from the discontinued project.

The UTC and IPUC 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. Based on testing in 2013, the modification appears to provide significant Total Dissolved Gas reduction. Ongoing design improvements have been made, and the Company expects to continue spill crest modifications over the next several years, in ongoing consultation with key stakeholders. 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 United States Fish and Wildlife Service (USFWS) listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company evaluated the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. Fishway designs for Cabinet Gorge are still being finalized. Construction cost estimates and schedules will be developed after several remaining issues are resolved, related to Montana's approval of fish transport from Idaho and expected minimum discharge requirements. 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.

Kettle Falls Generation Station - Diesel Spill Investigation and Remediation

In December 2013, the Company's operations staff at the Kettle Falls Generation Station discovered that approximately 10,000 gallons of diesel fuel had leaked underground from the piping system used to fuel heavy equipment. Avista Corp. made all proper agency notifications and worked closely with Ecology during the spill response and investigation phase. The Company installed ground water monitoring wells and there is no indication that ground or surface water is threatened by the spill.

There is no indication that Ecology is considering any enforcement action and the Company initiated a voluntary cleanup action with the installation of a recovery system.

As of December 31, 2014, the Company has recorded an estimated remediation liability and the Company will continue to monitor the remediation activities and will adjust any estimated remediation liability if necessary as new information is obtained. The Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows.

Collective Bargaining Agreements

The Company’s collective bargaining agreements with the IBEW 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 Avista Utilities' bargaining unit employees expired in March 2014. A new two-year agreement with this group was approved in January 2015 and has an expiration of March 2016. A new three-year agreement in Oregon, which covers approximately 50 employees, was approved in April 2014.

A new collective bargaining agreement with the local union of the IBEW in Alaska was signed in May 2013 and expires in March 2017. The collective bargaining agreement with the IBEW in Alaska represents approximately 54 percent of all AERC employees.

Investment Commitments

In October 2014, an indirect subsidiary of Avista Corp. entered into an agreement to fund a limited liability company in exchange for equity ownership in the limited liability company. This represents an unconditional commitment for $3.1 million, and the payments began in October 2014. As of December 31, 2014, the remaining commitment under the agreement was $2.8 million.

As of December 31, 2014, another indirect subsidiary of Avista Corp. also has an unconditional commitment to make investments in other companies for a total of $0.9 million. These investments will occur over a two-year period.

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’ or AEL&P's 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 21. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2017. The largest of these contracts provides for increases due to changes in the cost of living index and further provides flexibility in the annual obligation from year-to-year. Total payments under these contracts were as follows for the years ended December 31 (dollars in thousands):

	2014	2013	2012
Information service contract payments	$ 13,045	$ 12,647	$ 13,221

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):

	2015	2016	2017	2018	2019	Thereafter	Total
Contractual obligations	$ 9,047	$ 9,141	$ 9,237	$ —	$ —	$ —	$ 27,425

NOTE 22. REGULATORY MATTERS

Regulatory Assets and Liabilities

The following table presents the Company's regulatory assets and liabilities as of December 31, 2014 (dollars in thousands):

	Remaining Amortization Period	Receiving Regulatory Treatment (1) Earning A Return	Receiving Regulatory Treatment Not Earning A Return	(2) Expected Recovery or Refund	Total 2014	Total 2013
Regulatory Assets:						
Investment in exchange power-net	2019	$ 11,433	$ —	$ —	$ 11,433	$ 13,883
Regulatory assets for deferred income tax	(3)	100,412	—	—	100,412	71,421
Regulatory assets for pensions and other postretirement benefit plans	(4)	—	235,758	—	235,758	156,984
Current regulatory asset for utility derivatives	(5)	—	29,640	—	29,640	10,829
Unamortized debt repurchase costs	(6)	17,357	—	—	17,357	19,417
Regulatory asset for settlement with Coeur d'Alene Tribe	2059	47,887	—	—	47,887	49,198
Demand side management programs	(3)	—	4,603	—	4,603	9,576
Montana lease payments	(3)	1,984	—	—	1,984	3,022
Lancaster Plant 2010 net costs	2015	1,247	—	—	1,247	2,607
Deferred maintenance costs	2017	—	5,804	—	5,804	5,813
Power deferrals	(3)	8,291	—	—	8,291	5,065
Regulatory asset for interest rate swaps	(9)	—	77,063	—	77,063	—
Non-current regulatory asset for utility derivatives	(5)	—	24,483	—	24,483	23,258
Other regulatory assets	(3)	2,879	5,663	4,496	13,038	13,282
Total regulatory assets		$ 191,490	$ 383,014	$ 4,496	$ 579,000	$ 384,355
Regulatory Liabilities:						
Natural gas deferrals	(3)	$ 3,921	$ —	$ —	$ 3,921	$ 12,075
Power deferrals	(3)	14,186	—	—	14,186	17,904
Regulatory liability for utility plant retirement costs	(7)	254,140	—	—	254,140	242,850
Income tax related liabilities	(3)	—	14,534	—	14,534	9,203
Regulatory liability for interest rate swaps	(9)	—	460	—	460	33,543
Regulatory liability for Spokane Energy	(8)	—	—	29,028	29,028	25,046
Regulatory liability for rate refunds	(3)	—	4,275	5,856	10,131	2,490
Other regulatory liabilities	(3)	5,919	1,309	—	7,228	11,170
Total regulatory liabilities		$ 278,166	$ 20,578	$ 34,884	$ 333,628	$ 354,281

(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 with 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 Corp. 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 Corp. 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.

(9) For interest rate swap agreements, each period Avista Utilities records all mark-to-market gains and losses as assets and liabilities and records offsetting regulatory assets and liabilities, such that there is no income statement impact. This is similar to the treatment of energy commodity derivatives described above. Upon settlement of 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 term of the associated debt.

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 and availability of hydroelectric generation,
- the level and availability of thermal generation (including changes in fuel prices), and
- retail loads.

In Washington, the ERM allows Avista Utilities to periodically increase or decrease electric rates with UTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers. Total net deferred power costs under the ERM were a liability of $14.2 million as of December 31, 2014, and these deferred power cost balances represent amounts due to customers. As part of the approved Washington general rate case settlement in December 2012, during 2013 there was a one-year credit designed to return to customers $4.4 million from the existing ERM deferral balance which reduced the net average electric rate increase impact to customers in 2013. Additionally, during 2014 there was a one-year credit designed to return $9.0 million to electric customers from the ERM deferral balance, so the net average electric rate increase impact to customers effective January 1, 2014 was also reduced. The credits to customers from the ERM balances do 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 $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 customers. There is a 50 percent customers/50 percent Company sharing ratio when actual power supply expenses are higher (surcharge to customers) than the amount included in base retail rates within this band. There is a 75 percent customers/25 percent Company sharing ratio when actual power supply expenses are lower (rebate to customers) than the amount included in base retail rates within this band. To the extent that the annual power supply cost variance from the amount included in base rates exceeds $10.0 million, there is a 90 percent customers/10 percent Company share 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%

Avista Utilities has a PCA mechanism in Idaho that allows it to modify electric rates on October 1 of each year with 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 asset of $8.3 million as of December 31, 2014 compared to a regulatory asset of $5.1 million as of December 31, 2013.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Utilities files a 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 $3.9 million as of December 31, 2014 compared to a liability of $12.1 million as of December 31, 2013.

Washington General Rate Cases

2012 General Rate Cases

In December 2012, the UTC approved a settlement agreement in the Company's electric and natural gas general rate cases filed in April 2012. The settlement, effective January 1, 2013, provided that 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). Under the settlement, there was a one-year credit designed to return $4.4 million to electric customers from the ERM deferral balance so the net average electric rate increase impact to the Company's customers in 2013 was 2.0 percent. The credit to customers from the ERM balance did not impact the Company's earnings.

The approved settlement also provided that, effective January 1, 2014, base rates increased 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 settlement provided for a one-year credit designed to return $9.0 million to electric customers from the ERM deferral balance, so the net average electric rate increase to customers effective January 1, 2014 was 2.0 percent. The credit to customers from the ERM balance did not impact the Company's earnings. The ERM balance as of December 31, 2014 was a liability of $14.2 million.

The settlement agreement provided for an authorized return on equity of 9.8 percent and an equity ratio of 47.0 percent, resulting in an overall rate of return on rate base of 7.64 percent.

The December 2012 UTC Order approving the settlement agreement included certain conditions.

(1) The new retail rates that became effective on January 1, 2014 were temporary rates, and on January 1, 2015, electric and natural gas base rates were scheduled to revert back to 2013 levels absent any intervening action from the UTC. The original settlement agreement had a provision that the Company would not file a general rate case in Washington seeking new rates to take effect before January 1, 2015. In November 2014, the UTC approved a settlement agreement to the Company's Washington general rate cases which were originally filed in February 2014 with rates effective on January 1, 2015 (see further discussion below).

(2) In its Order, the UTC found that much of the approved base rate increase was 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 settlement agreement, this could result in base rates which are considered too high by the UTC. The Company is required to 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. Total utility capital expenditures among all jurisdictions were $294.4 million and $323.9 million for 2013 and 2014 respectively. The Company expects utility capital expenditures to be about $375 million for 2015 and $350 million in 2016, which are above the capital expenditures contemplated in the settlement agreement.

2014 General Rate Cases

In November 2014, the UTC approved an all-party settlement agreement related to the Company's electric and natural gas general rate cases filed in February 2014 and new rates became effective on January 1, 2015. The settlement is designed to increase annual electric base revenues by $12.3 million, or 2.5 percent, inclusive of a $5.3 million power supply update as required in the settlement agreement (explained below). The settlement is designed to increase annual natural gas base revenues by $8.5 million, or 5.6 percent.

Expiring and New Rebates and ERM

The parties agreed in the settlement that a credit of $8.3 million (including the $5.3 million power supply update) from the ERM deferral balance will be returned to electric customers to help offset the 2015 rate increase. This ERM balance represents lower net power supply costs in recent years than the costs embedded in base retail rates, which are being returned to customers in the form of a rebate. This rebate will not increase or decrease the Company's net income. Total net deferred power costs under the ERM were a liability of $14.2 million as of December 31, 2014, compared to a liability of $17.9 million as of December 31, 2013, and these deferred power cost balances represent amounts due to customers.

In addition, the Company's electric customers were receiving benefits from two rebates that expired at the end of 2014 and which reduced monthly energy bills by 2.8 percent during 2014. The parties agreed in the settlement that the Company will provide a rebate to customers of $8.6 million over an 18 month period related to the sale of renewable energy credits, which will partially replace the expiring rebates and reduce customers' monthly bills by 1.2 percent, beginning January 1, 2015. The net effect of the expiring rebates and the new rebate will result in an increase of approximately 1.6 percent beginning January 1, 2015. These rebates are passed through to customers and do not increase or decrease the Company's net income.

The overall change in customer billing rates from the approved settlement agreement, including the expiring and new rebates, is 2.5 percent for electric customers and 5.6 percent for natural gas customers effective January 1, 2015.

Power Supply Update and Customer Information and Work Management Systems Deferral

The settlement agreement included a provision that required the Company to update base power supply costs on November 1, 2014. This update to power supply costs was reflected in the overall electric revenue increase effective January 1, 2015, and reset the base power supply costs for the ERM calculations effective January 1, 2015. The amount of the updated power supply costs was a $5.3 million increase. The increase to customers from the power supply update was offset with the available ERM deferral balance for the calendar year 2015. The use of the ERM deferral balance for the offset will not increase or decrease the Company's net income.

The parties also agreed that the natural gas revenue requirement associated with the Company's investment in the Customer Information and Work Management Systems capital project (Project Compass) for 2015 will be deferred for regulatory purposes for recovery in retail rates through a future general rate case, based on the actual costs of the project at the time it goes into service. Project Compass went into service in February 2015. The future recovery of these costs and return on investment, estimated to be $2.0 million on a pre-tax basis, will be recognized in the future recovery period.

Decoupling

The parties agreed that the Company will implement electric and natural gas decoupling mechanisms for a five-year period beginning January 1, 2015. Decoupling is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. The Company's actual revenue, based on kilowatt hour and therm sales will vary, up or down, from the level established in a general rate case. This could be due to changes in weather, conservation or the economy. Per the terms of the settlement agreement and the decoupling mechanisms included therein, generally, electric and natural gas revenues will be adjusted each month to be based on the number of customers, rather than kilowatt hour and therm sales. The difference between revenues based on sales, and revenues based on the number of customers will be deferred and either surcharged or rebated to customers beginning in the following year. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to 3 percent on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

The decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations will be made for the prior calendar year. These earnings tests will reflect actual decoupled revenues, normalized power supply costs, and other normalizing adjustments.

- If there is a decoupling rebate balance for the prior year and Avista Corp. earns in excess of a 7.32 percent rate of return (ROR), the rebate to customers would be increased by 50 percent of the earnings in excess of the 7.32 percent ROR.
- If there is a decoupling rebate balance for the prior year and Avista Corp. earns a 7.32 percent ROR or less, only the base amount of the rebate to customers would be made.
- If there is a decoupling surcharge balance for the prior year and Avista Corp. earns in excess of a 7.32 percent ROR, the surcharge to customers would be reduced by 50 percent of the earnings in excess of the 7.32 percent ROR (or eliminated).
- If there is a decoupling surcharge balance for the prior year and Avista Corp. earns a 7.32 percent ROR or less, the base amount of the surcharge to customers would be made.

Original Request

The Company's original request filed with the UTC in February 2014 included a base electric rate increase of 3.8 percent (designed to increase annual electric revenues by $18.2 million). The Company also requested a base natural gas rate increase of 8.1 percent (designed to increase annual natural gas revenues by $12.1 million). Specific capital structure ratios and the cost of capital components were not agreed to in the settlement agreement, and the revenue increases in the settlement were not tied to the 7.32 percent ROR referenced above. The electric and natural gas revenue increases were negotiated numbers, with each party using its own set of assumptions underlying its agreement to the revenue increases. The parties agreed that the 7.32 percent ROR will be used to calculate the Allowance for Funds Used During Construction (AFUDC) and other purposes.

2015 General Rate Cases

In February 2015, the Company filed electric and natural gas general rates cases with the UTC. The Company has requested an overall increase in base electric rates of 6.6 percent (designed to increase annual electric revenues by $33.2 million) and an overall increase in base natural gas rates of 7.0 percent (designed to increase annual natural gas revenues by $12.0 million). The Company's requests are based on a proposed ROR on rate base of 7.46 percent with a common equity ratio of 48 percent and a 9.9 percent return on equity.

The major driver of these general rate case requests is to recover the costs associated with the ongoing need to maintain, replace and invest in the Company's facilities and equipment. Several significant capital investments the Company has made and is currently making, that are included in the filing are:

- the ongoing and multi-year redevelopment of the Little Falls Powerhouse on the Spokane River,
- the continuing rehabilitation of the Nine Mile Powerhouse on the Spokane River,
- information technology upgrades that include the replacement of the Company's customer information and work management systems (which were implemented in February 2015),
- the ongoing project to systematically replace portions of Aldyl-A natural gas distribution pipe, and
- technology investments for deploying Advanced Metering Infrastructure in Washington, including installation of advanced meters, beginning in 2016.

The UTC has up to 11 months to review the filings and issue a decision.

Idaho General Rate Cases

2012 General Rate Cases

In March 2013, the IPUC approved a settlement agreement in the Company's electric and natural gas general rate cases filed in October 2012. As agreed to in the settlement, new rates were implemented in two phases: April 1, 2013 and October 1, 2013. Effective April 1, 2013, base rates increased for the Company's Idaho natural gas customers by an overall 4.9 percent (designed to increase annual revenues by $3.1 million). There was no change in base electric rates on April 1, 2013. However, the settlement agreement provided for the recovery of the costs of the Palouse Wind Project, subject to the 90 percent customers/10 percent Company sharing ratio, through the PCA mechanism until these costs are reflected in base retail rates in the next general rate case.

The settlement also provided that, effective October 1, 2013, base rates increased for Idaho natural gas customers by an overall 2.0 percent (designed to increase annual revenues by $1.3 million). A credit resulting from deferred natural gas costs of $1.6 million was 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 was 0.3 percent.

Further, the settlement provided that, effective October 1, 2013, base rates increased for Idaho electric customers by an overall 3.1 percent (designed to increase annual revenues by $7.8 million). A $3.9 million credit resulting from a payment to be made to Avista Corp. by the Bonneville Power Administration relating to its prior use of Avista Corp.'s transmission system was 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 was 1.9 percent.

The $1.6 million credit to Idaho natural gas customers and the $3.9 million credit to Idaho electric customers did not impact the Company's net income.

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

The settlement also included 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. will share with customers 50 percent of any earnings above the 9.8 percent. In 2013, the Company's returns exceeded this level and $3.9 million was deferred for future ratemaking treatment for Idaho electric customers and $0.4 million for Idaho natural gas customers. Of the electric deferral amount, $2.0 million was recorded in 2013 and $1.9 million was recorded in the first quarter of 2014 based on a revision of the allocation of costs between Idaho and Washington for regulatory purposes. The ratemaking treatment for these deferrals is addressed in the 2014 rate plan extension request explained below.

In 2014, the Company's returns exceeded a 9.8 percent return on equity and the Company deferred for future ratemaking treatment $7.5 million (including the $1.9 million related to 2013 that was recorded in 2014) for Idaho electric customers and $0.2 million for Idaho natural gas customers. The period over which these amounts will be returned to customers has not yet been determined by the IPUC.

2014 Rate Plan Extension

The Company did not file new general rate cases in Idaho in 2014, instead, it developed an extension to the 2013 and 2014 rate plan and reached a settlement agreement with all interested parties.

In September 2014, the IPUC approved the settlement, which reflects agreement among all interested parties, for a one-year extension to the current rate plan, which was set to expire on December 31, 2014. Under the approved extension, base retail rates will remain unchanged through December 31, 2015.

The settlement will provide an estimated $3.7 million increase in pre-tax income by reducing planned expenses in 2015 for Idaho operations, resulting from:

- the delay of the beginning of the amortization of the 2013 previously deferred operations and maintenance costs pertaining to the Colstrip and Coyote Springs 2 thermal generating facilities from 2015 to 2016, and
- deferred accounting, for later review and recovery, of the majority of the costs associated with Project Compass, which was implemented in February 2015.

The settlement agreement establishes an ROE deadband between the currently authorized ROE of 9.8 percent and a 9.5 percent ROE. Under the settlement agreement, the Company will be allowed to use any 2014 Idaho after-the-fact earnings test deferral (described above under "2012 General Rate Cases") to support an actual earned ROE in 2015 up to 9.5 percent. For 2014, the Company deferred a total of $7.7 million for the 2014 after-the-fact earnings test, which includes the $1.9 million recorded in 2014 related to the 2013 earnings test. During 2015, if the Company earns more than the 9.8 percent ROE, 50 percent of the earnings above 9.8 percent will be shared with customers through future ratemaking.

As part of the settlement, the Company agreed not to file a general rate case in 2014, and would file no earlier than May 31, 2015 for new electric or natural gas base retail rates to become effective on or after January 1, 2016. In addition, the settlement replaced two rebates, which expired on January 1, 2015, that were reducing customers' monthly energy bills by 1.3 percent for electric and 1.7 percent for natural gas. The rebates were replaced for a one-year period, through December 31, 2015, using existing deferral balances due to customers, which will have no impact on the Company's net income. This provision does not preclude the filing of other rate adjustments such as the PGA.

Oregon General Rate Cases

2013 General Rate Case

In January 2014, the OPUC approved a settlement agreement to the Company's natural gas general rate case (originally filed in August 2013). As agreed to in the settlement, new rates were implemented in two phases: February 1, 2014 and November 1, 2014. Effective February 1, 2014, rates increased for Oregon natural gas customers on a billed basis by an overall 4.4 percent (designed to increase annual revenues by $3.8 million). Effective November 1, 2014, rates for Oregon natural gas customers were to increase on a billed basis by an overall 1.6 percent (designed to increase annual revenues by $1.4 million).

The billed rate increase on November 1, 2014 was dependent upon the completion of Project Compass and the actual costs incurred through September 30, 2014, and the actual costs incurred through June 30, 2014 related to the Company's Aldyl A distribution pipeline replacement program. As noted elsewhere, Project Compass was completed in February 2015. The November 1, 2014 rate increase was reduced from $1.4 million to $0.3 million due to the delay of Project Compass.

The approved settlement agreement provides for an overall authorized rate of return of 7.47 percent, with a common equity ratio of 48 percent and a 9.65 percent return on equity.

2014 General Rate Case

In January 2015, the Company filed an all-party settlement agreement with the OPUC related to the Company's natural gas general rate case, which was originally filed in September 2014. The settlement agreement was designed to increase base natural gas revenues by 6.1 percent or $6.1 million. This base rate increase was offset by $0.3 million for a separate rate adjustment that the Company is already receiving from customers and it was offset by a $0.8 million credit to customers related to having an early implementation date for the revenue increase (prior to the full 10 months allowed in Oregon for the OPUC to make a decision on the case and new rates to take effect). The net increase to the Company after the two offsets was $5.0 million. The parties to the settlement agreement had requested a decision from the OPUC prior to March 1, 2015, such that new retail rates could be effective on March 1, 2015.

This settlement agreement provided for an overall authorized rate of return of 7.52 percent with a common equity ratio of 51 percent and a 9.5 percent return on equity.

The original request was for an overall increase in base natural gas rates of 9.3 percent (designed to increase annual natural gas revenues by $9.1 million) and it was based on a proposed rate of return of 7.77 percent with a common equity ratio of 51 percent and a 9.9 percent return on equity.

On February 23, 2015, the OPUC issued an order rejecting the all-party settlement agreement filed with the OPUC by the parties on January 21, 2015. The OPUC expressed concerns related to three issues: 1) the proposed early rate implementation credit; 2) the combination of proposed rate increases and rate decreases across the customer classes (rate spread); and 3) the customer count tracking mechanism. With regard to the early rate implementation credit, the order stated, among other things, that there was no evidence in the record that explains the derivation of the rate credit amount, or why the credit would be applied to all customer classes. On rate spread, the OPUC's order expressed concern about proposed increases to rates for some customer classes, and decreases for other customer classes, absent more compelling evidence. And finally, the OPUC expressed concern that the customer count tracking mechanism is contrary to standard ratemaking.

The OPUC's order directed the Administrative Law Judge to convene a prehearing conference to schedule further proceedings in a manner that will allow for the timely completion of the case. The OPUC's order also encouraged the parties to come back with a partial stipulation that encompasses these issues. Furthermore, the OPUC stated that its order does not preclude the parties from reaching a global settlement of all issues that addresses the concerns identified by the OPUC.

Bonneville Power Administration Reimbursement and Reardan Wind Generation Project

In May 2013, the UTC approved the Company's Petition for an order authorizing certain accounting and ratemaking treatment related to two issues. The first issue relates to transmission revenues associated with a settlement between Avista Corp. and the BPA, whereby the BPA reimbursed the Company $11.7 million for Bonneville's past use of Avista Corp.'s transmission system. The second issue relates to $4.3 million of costs the Company incurred over the past several years for the development of a wind generation project site near Reardan, Washington, which has been terminated. The UTC authorized the Company to retain $7.6 million of the BPA settlement payment, representing the entire portion of the settlement allocable to the Washington business. However, this amount was deemed to first reimburse the Company for the $2.5 million of Reardan project costs that were allocable to the Washington business, leaving $5.1 million to be retained for the benefit of shareholders.

The BPA agreed to pay $3.2 million annually for the future use of Avista Corp.'s transmission system. The Company separately tracked and deferred for the customers' benefit, the Washington portion of these revenue payments in 2013 and 2014 ($2.1 million annually). The Company implemented a one-year $4.2 million rate decrease for customers effective January 1, 2014 to partially offset the electric general rate increase effective January 1, 2014. To the extent actual revenues from the BPA in 2013 and 2014 differ from those refunded to customers in 2014, the difference will be added to or subtracted from the ERM balance. In Idaho, under the terms of the approved rate case settlement, 90 percent of the portion of the BPA settlement allocable to the Idaho business ($4.1 million) was credited back to customers over 15 months, beginning October 2013, and the Company is amortizing the Idaho portion of Reardan costs ($1.7 million) over a two-year period, beginning April 2013.

NOTE 23. 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; therefore, it is considered one segment. Ecova was a provider of facility information and cost management services for multi-site customers throughout North America. The Ecova business segment was disposed of as of June 30, 2014. All income statement amounts were reclassified to discontinued operations on the Consolidated Statements of Income for all periods presented. 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. On July 1, 2014, the Company completed its acquisition of AERC. Based on the way AERC is managed and the financial reports that are reviewed by the Chief Operating Decision Maker, AEL&P, the primary subsidiary of AERC is considered a separate reportable business segment and the remaining activities of AERC are included in the Other category. All goodwill associated with the AERC acquisition was assigned to the AEL&P reportable business segment.

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

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the year ended December 31, 2014:						
Operating revenues	$ 1,413,499	$ 21,644	$ 1,435,143	$ 39,219	$ (1,800)	$ 1,472,562
Resource costs	672,344	5,900	678,244	—	—	678,244
Other operating expenses	280,964	5,868	286,832	32,218	(1,800)	317,250
Depreciation and amortization	126,987	2,583	129,570	610	—	130,180
Income from operations	239,976	6,221	246,197	6,391	—	252,588
Interest expense (2)	73,750	1,382	75,132	1,004	(384)	75,752
Income taxes	67,634	1,816	69,450	2,790	—	72,240
Net income from continuing operations attributable to Avista Corp. shareholders	113,263	3,152	116,415	3,236	166	119,817
Capital expenditures (3)	323,931	1,585	325,516	406	—	325,922
For the year ended December 31, 2013:						
Operating revenues	$ 1,403,995	$ —	$ 1,403,995	$ 39,549	$ (1,800)	$ 1,441,744
Resource costs	689,586	—	689,586	—	—	689,586
Other operating expenses	276,228	—	276,228	40,451	(1,800)	314,879
Depreciation and amortization	117,174	—	117,174	581	—	117,755
Income (loss) from operations	232,572	—	232,572	(1,483)	—	231,089
Interest expense (2)	75,663	—	75,663	2,247	(325)	77,585
Income taxes	60,472	—	60,472	(2,458)	—	58,014
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	108,598	—	108,598	(4,650)	325	104,273
Capital expenditures (3)	294,363	—	294,363	371	—	294,734

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the year ended December 31, 2012:						
Operating revenues	$ 1,354,185	$ —	$ 1,354,185	$ 38,953	$ (1,800)	$ 1,391,338
Resource costs	693,127	—	693,127	—	—	693,127
Other operating expenses	276,780	—	276,780	39,841	(1,800)	314,821
Depreciation and amortization	112,091	—	112,091	792	—	112,883
Income (loss) from operations	188,778	—	188,778	(1,680)	—	187,098
Interest expense (2)	72,552	—	72,552	3,437	(344)	75,645
Income taxes	42,842	—	42,842	(3,078)	—	39,764
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	81,704	—	81,704	(5,319)	334	76,719
Capital expenditures (3)	271,187	—	271,187	666	—	271,853
Total Assets:						
As of December 31, 2014	$ 4,367,926	$ 264,195	$ 4,632,121	$ 80,210	$ —	$ 4,712,331
As of December 31, 2013 (4)	$ 3,940,998	$ —	$ 3,940,998	$ 81,282	$ —	$ 4,022,280

(1) Intersegment eliminations reported as operating revenues and resource costs represent intercompany purchases and sales of electric capacity and energy between Avista Utilities and Spokane Energy (included in other). Intersegment eliminations reported as interest expense and net income (loss) attributable to Avista Corp. shareholders represent intercompany interest.

(2) Including interest expense to affiliated trusts.

(3) The capital expenditures for the other businesses are included as other capital expenditures on the Consolidated Statements of Cash Flows. The remainder of the balance included in other capital expenditures on the Consolidated Statements of Cash Flows are related to Ecova.

(4) The consolidated total assets presented here as of December 31, 2013 exclude total assets at Ecova of $339.6 million.

NOTE 24. 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. During the second quarter of 2014, Avista Corp. reported Ecova as discontinued operations (see Note 5). Accordingly, periods prior to the second quarter of 2014 were restated to reflect Ecova as discontinued operations.

A summary of quarterly operations (in thousands, except per share amounts) for 2014 and 2013 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2014				
Operating revenues from continuing operations	$ 446,578	$ 312,580	$ 301,558	$ 411,846
Operating expenses from continuing operations	356,236	249,849	268,796	345,093
Income from continuing operations	$ 90,342	$ 62,731	$ 32,762	$ 66,753
Net income from continuing operations	$ 47,466	$ 31,270	$ 10,526	$ 30,604
Net income (loss) from discontinued operations	1,515	69,312	(55)	1,639
Net income	48,981	100,582	10,471	32,243
Net loss (income) attributable to noncontrolling interests	(482)	289	(20)	(23)
Net income attributable to Avista Corporation shareholders	$ 48,499	$ 100,871	$ 10,451	$ 32,220
Amounts attributable to Avista Corp. shareholders:				
Net income from continuing operations attributable to Avista Corp. shareholders	$ 47,476	$ 31,254	$ 10,506	$ 30,581
Net income (loss) from discontinued operations attributable to Avista Corp. shareholders	1,023	69,617	(55)	1,639
Net income attributable to Avista Corp. shareholders	$ 48,499	$ 100,871	$ 10,451	$ 32,220
Outstanding common stock:				
Weighted average, basic	60,122	60,184	63,934	62,290
Weighted average, diluted	60,168	60,463	64,244	62,671
Earnings per common share attributable to Avista Corp. shareholders, diluted:				
Earnings per common share from continuing operations	$ 0.79	$ 0.52	$ 0.16	$ 0.48
Earnings per common share from discontinued operations	0.02	1.15	—	0.03
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 0.81	$ 1.67	$ 0.16	$ 0.51

	Three Months Ended			
	March 31	June 30	September 30	December 31
2013				
Operating revenues from continuing operations	$ 440,499	$ 307,488	$ 289,477	$ 404,280
Operating expenses from continuing operations	358,361	252,518	259,650	340,126
Income from continuing operations	$ 82,138	$ 54,970	$ 29,827	$ 64,154
Net income from continuing operations	$ 41,219	$ 24,239	$ 8,483	$ 30,392
Net income from discontinued operations	1,882	1,491	3,448	1,140
Net income	43,101	25,730	11,931	31,532
Net loss (income) attributable to noncontrolling interests	(760)	(73)	(518)	134
Net income attributable to Avista Corporation shareholders	$ 42,341	$ 25,657	$ 11,413	$ 31,666
Amounts attributable to Avista Corp. shareholders:				
Net income from continuing operations attributable to Avista Corp. shareholders	$ 41,220	$ 24,212	$ 8,450	$ 30,391
Net income from discontinued operations attributable to Avista Corp. shareholders	1,121	1,445	2,963	1,275
Net income attributable to Avista Corp. shareholders	$ 42,341	$ 25,657	$ 11,413	$ 31,666
Outstanding common stock:				
Weighted average, basic	59,866	59,937	59,994	60,037
Weighted average, diluted	59,898	59,962	60,032	60,087
Earnings per common share attributable to Avista Corp. shareholders, diluted:				
Earnings per common share from continuing operations	$ 0.69	$ 0.40	$ 0.14	$ 0.51
Earnings per common share from discontinued operations	0.02	0.03	0.05	0.02
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 0.71	$ 0.43	$ 0.19	$ 0.53

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, 2014.

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 (2013) 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, 2014 is effective at a reasonable assurance level.

The Company acquired AERC on July 1, 2014 and as of December 31, 2014, the Company's management is still in the process of integrating AERC into the overall control environment. As such, AERC has been excluded from Management's Report on Internal Control Over Financial Reporting as of December 31, 2014. AERC's financial results constitute 6% of net and total assets, respectively, 1% of revenues, and 2% of net income of the consolidated financial statement amounts as of and for the year ended December 31, 2014. See Note 4 of the Notes to Consolidated Financial Statements for further discussion regarding the acquisition of AERC.

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, 2014.

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 Shareholders 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, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in *Management's Report on Internal Control Over Financial Reporting*, management excluded from its assessment the internal control over financial reporting at Alaska Energy and Resources Company, which was acquired on July 1, 2014 and whose financial statements constitute 6% and 6% of net and total assets, respectively, 1% of revenues, and 2% of net income of the consolidated financial statement amounts as of and for the year ended December 31, 2014. Accordingly, our audit did not include the internal control over financial reporting at Alaska Energy and Resources Company. 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, 2014, based on the criteria established in *Internal Control - Integrated Framework (2013)* 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, 2014 of the Company and our report dated February 25, 2015 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 25, 2015

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 7, 2015, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 28, 2014, relating to its Annual Meeting of Shareholders held on May 8, 2014.

Executive Officers of the Registrant

Name	Age	Business Experience
Scott L. Morris	57	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	51	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	61	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	59	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	53	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.
Jason R. Thackston	44	Senior Vice President since January 2014; 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.
Christy M. Burmeister-Smith	58	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	56	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	59	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.

Executive Officers of the Registrant

Name	Age	Business Experience
David J. Meyer	61	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	56	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.
Roger D. Woodworth	58	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.
Kevin J. Christie	47	Vice President since February 2015; Vice President of Customer Solutions since February 2015; various other management and staff positions with the Company since 2005.

All of the Company's executive officers, with the exception of James M. Kensok, Don F. Kopczynski, David J. Meyer, Kelly O. Norwood and Kevin J. Christie, were officers or directors of one or more of the Company's subsidiaries in 2014. 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 7, 2015, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 28, 2014, relating to its Annual Meeting of Shareholders held on May 8, 2014.

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 SEC in connection with the Registrant's annual meeting of shareholders to be held on May 7, 2015.

(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 7, 2015, from such Proxy Statement; and

- prior to such date, from the Registrant's definitive Proxy Statement, dated March 28, 2014, relating to its Annual Meeting of Shareholders held on May 8, 2014.

(c) Changes in control:

None.

(d) Securities authorized for issuance under equity compensation plans as of December 31, 2014:

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)	—	$ —	373,023

(1) Excludes unvested restricted shares and performance share awards granted under Avista Corp.'s Long Term Incentive Plan. At December 31, 2014, 112,042 Restricted Share awards were outstanding. Performance and market-based share awards may be paid out at zero shares at a minimum achievement level; 345,851 shares at target level; or 691,702 shares at a maximum level. Because there is no exercise price associated with restricted shares or performance and market-based 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 7, 2015, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 28, 2014, relating to its Annual Meeting of Shareholders held on May 8, 2014.

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 7, 2015, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 28, 2014, relating to its Annual Meeting of Shareholders held on May 8, 2014.

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, 2014, 2013 and 2012

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2014, 2013 and 2012

Consolidated Balance Sheets as of December 31, 2014 and 2013

Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013 and 2012

Consolidated Statements of Equity and Redeemable Noncontrolling Interests for the Years Ended December 31, 2014, 2013 and 2012

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules:

None

(a) 3. Exhibits:

Reference is made to the Exhibit Index commencing on page 155. 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 25, 2015	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 25, 2015
/s/ Mark T. Thies Mark T. Thies (Senior Vice President, Chief Financial Officer, and Treasurer)	Principal Financial Officer	February 25, 2015
/s/ Christy M. Burmeister-Smith Christy M. Burmeister-Smith (Vice President, Controller and Principal Accounting Officer)	Principal Accounting Officer	February 25, 2015
/s/ Erik J. Anderson Erik J. Anderson	Director	February 25, 2015
/s/ Kristianne Blake Kristianne Blake	Director	February 25, 2015
/s/ Donald C. Burke Donald C. Burke	Director	February 25, 2015
/s/ John F. Kelly John F. Kelly	Director	February 25, 2015
/s/ Rebecca A. Klein Rebecca A. Klein	Director	February 25, 2015
/s/ Marc F. Racicot Marc F. Racicot	Director	February 25, 2015

/s/ Heidi B. Stanley Heidi B. Stanley	Director	February 25, 2015
/s/ R. John Taylor R. John Taylor	Director	February 25, 2015
/s/ Janet D. Widmann Janet D. Widmann	Director	February 25, 2015

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 filed as of November 14, 2014)	3.2	Bylaws of Avista Corporation, as amended November 14, 2014.
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.
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.

	Previously Filed (1)		
Exhibit	With Registration Number	As Exhibit	
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.
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.

Exhibit	Previously Filed (1) With Registration Number	As Exhibit	
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.
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 August 14, 2013)	4.1	Fifty-Fifth Supplemental Indenture, dated as of August 1, 2013.
4.57	1-3701 (with Form 8-K dated as of April 18, 2014)	4.1	Fifty-Sixth Supplemental Indenture, dated as of April 1, 2014.
4.58	1-3701 (with Form 8-K dated as of December 18, 2014)	4.1	Fifty-Seventh Supplemental Indenture, dated as of December 1, 2014.
4.59	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.
4.60	333-82165	4(a)	Indenture dated as of April 1, 1998 between Avista Corporation and The Bank of New York, as Successor Trustee.
4.61	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.
4.62	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.
4.63	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.
4.64	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.

	Previously Filed (1)		
Exhibit	With Registration Number	As Exhibit	
10.3	1-3701 (with Form 8-K dated as of April 18, 2014)	10.1	Second Amendment to Credit Agreement, dated as of April 18, 2014, among Avista Corporation, Wells Fargo Bank, National Association, as an Issuing Bank, Union Bank, N.A. as Administrative Agent and an Issuing Bank, and the financial institutions identified hereof as Continuing Lenders and Exiting Lender.
10.4	1-3701 (with Form 8-K dated as of April 18, 2014)	10.2	Bond Delivery Agreement, dated as of April 18, 2014, between Avista Corporation and Union Bank, N.A.
10.5	1-3701 (with Form 8-K dated as of August 14, 2013)	10.1	Term Loan Agreement, dated as of August 14, 2013, among Avista Corporation, the Lenders Party hereto and Union Bank N.A. as Administrative Agent.
10.6	1-3701 (with Form 8-K dated as of August 14, 2013)	10.2	Bond Delivery Agreement, dated as of August 14, 2013, between Avista Corporation and Union Bank, N.A.
10.7	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.
10.8	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).
10.9	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).
10.10	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).
10.11	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.
10.12	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.
10.13	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.
10.14	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.
10.15	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.
10.16	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.
10.17	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.

Exhibit	Previously Filed (1) With Registration Number	As Exhibit	
10.18	1-3701 (with 2011 Form 10-K)	10.15	Avista Corporation Executive Deferral Plan. (3)
10.19	1-3701 (with 2011 Form 10-K)	10.16	Avista Corporation Executive Deferral Plan. (3)(8)
10.20	1-3701 (with 2011 Form 10-K)	10.17	Avista Corporation Supplemental Executive Retirement Plan. (3)(8)
10.21	1-3701 (with 2011 Form 10-K)	10.18	Avista Corporation Supplemental Executive Retirement Plan. (3)(8)
10.22	1-3701 (with 1992 Form 10-K)	10(t)-11	The Company's Unfunded Supplemental Executive Disability Plan. (3)
10.23	1-3701 (with 2007 Form 10-K)	10.34	Income Continuation Plan of the Company. (3)
10.24	1-3701 (with 2010 Definitive Proxy Statement filed March 31, 2010)	Appendix A	Avista Corporation Long-Term Incentive Plan. (3)
10.25	1-3701 (with 2010 Form 10-K)	10.23	Avista Corporation Performance Award Plan Summary. (3)
10.26	1-3701 (with 2010 Form 10-K)	10.24	Avista Corporation Performance Award Agreement 2010. (3)
10.27	1-3701 (with 2011 Form 10-K)	10.24	Avista Corporation Performance Award Agreement 2011. (3)
10.28	1-3701 (with 2012 Form 10-K)	10.25	Avista Corporation Performance Award Agreement 2012. (3)
10.29	1-3701 (with 2013 Form 10-K)	10.27	Avista Corporation Performance Award Agreement 2013. (3)
10.30	(2)		Avista Corporation Performance Award Agreement 2014. (3)
10.31	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)
10.32	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)
10.33	333-47290	99.1	Non-Officer Employee Long-Term Incentive Plan.
10.34	1-3701 (with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. (3)(5)
10.35	1-3701 (with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. (3)(6)
10.36	1-3701 (with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. (3)(7)
10.37	1-3701 (with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. (3)(7)
10.38	(2)		Avista Corporation Non-Employee Director Compensation.
12	(2)		Statement Re: computation of ratio of earnings to fixed charges.
21	(2)		Subsidiaries of Registrant.
23	(2)		Consent of Independent Registered Public Accounting Firm.
31.1	(2)		Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002).
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).

	Previously Filed (1)		
Exhibit	With Registration Number	As Exhibit	
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, 2014, 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. This only applies to Kevin J. Christie.
(8) Applies to executive officers appointed after February 4, 2011. This only applies to Kevin J. Christie.

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") as designated by the Avista Corporation Compensation and Organization 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 **(Participant's name)**

   (b) The "Grant Date" is February 6, 2014.

   (c) The total target number of eligible "Performance Awards" shall be **(# of)** 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, 2014 and ending on December 31, 2016.

2. **Conditions to Award**. Pursuant to this Award, the number of Performance Awards earned will depend upon the Company's performance against specific performance metrics. The performance metrics are (i) Relative Total Shareholder Return, which accounts for **(# of)** units of the total target award as set forth in section 1(c), and (ii) Cumulative Earnings Per Share ("CEPS") which accounts for **(# of)** units of the total target award set forth in section 1(c). The total number of shares of Stock that will be issued in the settlement of this Award, based upon the Company's satisfaction of the metrics, will be determined by multiplying the Target Number of units allocated for each metric set forth in this section 2 by the applicable Payout Factor in accordance with the provisions of Exhibit 1 and Exhibit 2, which is attached to and forms a part of this Agreement.

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 and Exhibit 2, 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 the date the Plan Administrator certifies the attainment of the

performance goals), 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. The Dividend Equivalent Rights in respect of any Performance Awards that are not earned as of the end of a Performance Cycle, shall be forfeited as of the end of the Performance Cycle.

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 and Exhibit 2, 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 Cycle, such Participant will be deemed to have terminated after the end of such Performance Cycle. 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 and Exhibit 2, 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 and Exhibit 2 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 Performance

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.

11. **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.

12. **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 for the eastern district of Washington.

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 effective 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
Relative Total Shareholder Return Measures and Goals 2014 - 2016 Performance Cycle

The following graph and table represent the relationship between the Company's relative three-year Total Shareholder Return ("TSR") commencing January 1, 2014 and ending December 31, 2016 and the award opportunity. The number of shares delivered at the end of the three-year Performance Cycle can range from zero to 200% of the target number of units allocated under this metric. The actual payment depends on Avista's three-year TSR compared to the returns reported in the S&P 400 Utilities Index. To receive
100% of the Award allocated under this metric, Avista must perform at the 50th percentile among the S&P 400 Utilities Index. To receive 200% of the Award allocated to this metric, Avista must perform at the 100th percentile ranking. If Avista performs below the 40th percentile ranking, no awards or Dividend
Equivalents Rights will be received. Dividend Equivalent Rights are calculated and paid out in cash when
and to the extent the Performance Awards are paid. The following graph demonstrates the relationship between TSR ranking and various payout factors. Performance Awards are interpolated on a straight line for performance results between the figures shown.

	Relative TSR Percentile	Payout Factor
Maximum	100th	200%
	85th	150%
	70th	125%
Target	50th	100%
	45th	70%
Threshold	40th	40%
	<40th	No Award

TSR is calculated using S&P Research Insight and reflects share price appreciation plus the impact of dividend distributions and the reinvestment of such dividends. To compute the TSR, an adjusted price is calculated by applying a monthly return factor to the average closing share prices on the last trading day of November and December for the start and end of the Performance Cycle.

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.

Settlement Formula Example:
Assuming that 1,100 Performance Awards were allocated under this metric at the beginning of the Performance Cycle and Avista's TSR ranked at the 45th percentile after the three-year Performance Cycle, the Participant would receive 70% of 1,100 or 770 Shares of Common Stock plus Dividend Equivalent Rights.

Payout Factor (% of Target)		Target # of Performance Awards		Final # of Common Stocks Awarded
70%	X	1,100	=	770 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%
56	(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 Performance Cycle. Below are additional assumptions used in Avista's calculation for TSR.

General Assumptions:
The starting and ending prices are determined by averaging the closing price on the last trading day of November and the last trading day of December at the beginning and the end of the Performance Cycle.

For example, the stock price for the start of the Performance Cycle for Avista is $21.46, the average of $21.54 (12/31/2007) and $21.38 (11/30/2007). Dividends are reinvested on a daily basis. The ex-date dividends per share is used. Returns will be calculated over the applicable Performance Cycle.

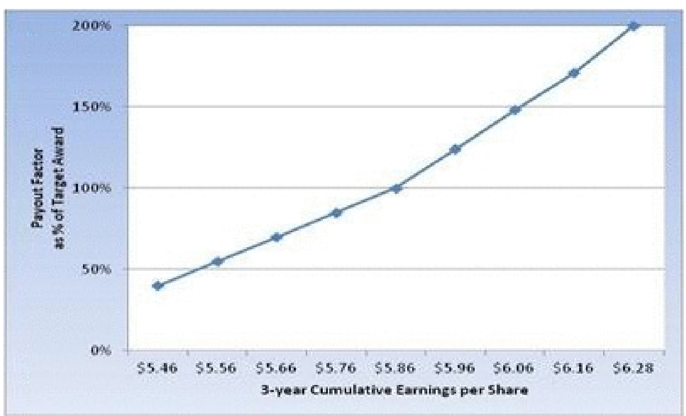
Date	Closing Price	Dividend	Daily TSR
11/23/2007	21.08	—	NA
11/26/2007	20.90	—	(0.8539)%
11/27/2007	21.09	0.15	1.6268%*
11/28/2007	21.54	—	2.1337%
11/29/2007	21.38	—	(0.7428)%
11/30/2007	21.38	—	—%
Cumulative TSR 11/23/2007 to 11/30/2007			2.1347%

* [(21.09 + 0.15) / 20.90] -1

EXHIBIT 2

Performance Award Plan
Cumulative Earnings Per Share Measures and Goals 2014 - 2016 Performance Period

The following graph and table represent the relationship between the Company's Cumulative Earnings Per Share ("CEPS") commencing January 1, 2014 and ending December 31, 2016 and the Performance Award opportunity. The number of shares delivered at the end of the three-year Performance Cycle can range from zero to 200% of the target number of units allocated under this metric. The actual payment depends on Avista's CEPS over the three-year Performance Cycle. To receive 100% of the Performance Award allocated under this metric, Avista must achieve CEPS compounded growth of 4.50% or $5.86 based on 2014 earnings guidance. To receive 200% of the Award, Avista must achieve CEPS compounded growth of 6.00% or $6.28; if CEPS compounded growth is less than 3.00% or is below $5.46, no Performance Awards or Dividend Equivalent Rights will be earned. Dividend Equivalent Rights are calculated and paid out in cash when and to the extent the Performance Awards are paid. The following graph demonstrates the relationship between CEPS and various payout factors. Performance Awards are interpolated on a straight line for performance results between the figures shown.



	Cumulative EPS	Payout Factor
Maximum	$6.28	200%
	$6.16	171%
	$6.06	148%
	$5.96	124%
Target	$5.86	100%
	$5.76	85%
	$5.66	70%
	$5.56	50%
Threshold	$5.46	40%
	<$5.46	No Award

Performance is tracked over a three-year Performance Cycle thereby focusing on sustainability.

The performance metric CEPS provides for Performance Awards if the Company's cumulative EPS grows at a certain rate on a compounded annual basis. Cumulative EPS is fully diluted earnings per share determined in accordance with generally accepted accounting principles, and may be adjusted to remove the effects of such items as regulatory charges, income tax legislative changes and/or items of a non- routine or an extraordinary nature as determined by the Plan Administrator.

Settlement Formula Example:
Assuming that 550 Performance Awards were allocated under this metric at the beginning of the Performance Cycle and Avista's cumulative growth was 4.875% and CEPS was $5.96 after the three- year Performance Cycle, the Participant would receive 124% of 550 or 682 Shares of Common Stock plus Dividend Equivalent Rights.

Payout Factor (% of Target)		Target # of Performance Awards		Final # of Common Stocks Awarded
124%	X	550	=	682 plus Dividends

Using the example formulas in Exhibit 1 and Exhibit 2, the Participant would receive 88% of 1,650 (total target # of Performance Awards granted) or 1,452 Shares of Common Stock plus Dividend Equivalent Rights.

	Payout Factor (% of Target)		Target # of Performance Awards		Final # of Common Stocks Awarded
TSR	70%	X	1,100	=	770
CEPS	124%	X	550	=	682
Total	**88%**	**X**	**1,650**	**=**	**1,452**

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 10.38

Avista Corporation
Non-Employee Director Compensation - 2014

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 $7,500 annual retainer, with the exception of the Audit Committee Chair, who received an additional $13,000 annual retainer and the Compensation Committee Chair, who received an additional $10,000 annual retainer. The Lead Director received an additional annual retainer of $20,000.

In addition, any non-employee director who served as a director of a subsidiary of the Company received from the Company a $15,000 annual retainer and a meeting fee of $1,500 for each subsidiary Board meeting and Committee meeting the director attended. The Audit Committee Chair of a subsidiary received an additional annual chair retainer of $10,000. Directors Anderson, Blake, Burke and Kelly hold Board positions with a subsidiary of the Company.

Each year, the Governance Committee reviews all components of director compensation. During 2014, the Governance Committee engaged Meridian to assist in this review. The information provided by Meridian was 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 400 Utilities Index, as well as NorthWestern Energy, Northwest Natural Gas Company, and Portland General Electric Company.

At its September 3, 2014 meeting, the Board reviewed survey results from Meridian regarding current pay practices for director compensation. The Board approved an increase in the annual retainer of an additional 9,000, effective September 12, 2014. The total annual retainer will now be $125,000 with $50,000 of the total retainer to be paid in stock each year. Directors will have the option of taking the remaining $75,000 in cash, stock or a combination of both cash and stock.

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. Outside directors are expected to achieve a minimum investment of five times their equity retainer in Company common stock within five years of becoming a Board member, and retain at least that level of investment during his/her tenure as a Board member. 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.

There were no annual stock option grants or non-stock incentive plan compensation payments to directors for services in 2014 and none are currently contemplated under the current compensation structure. The Company also does not provide a retirement plan or deferred compensation plan to its directors.

Exhibit 12

AVISTA CORPORATION

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

	Years Ended December 31				
	2014	2013	2012	2011	2010
Fixed charges, as defined:					
Interest charges	$ 74,025	$ 73,772	$ 71,843	$ 69,536	$ 71,734
Amortization of debt expense and premium - net	3,635	3,813	3,803	4,617	4,414
Interest portion of rentals	1,187	1,146	1,294	1,139	1,248
Total fixed charges	$ 78,847	$ 78,731	$ 76,940	$ 75,292	$ 77,396
Earnings, as defined:					
Pre-tax income from continuing operations	$ 192,106	$ 162,347	$ 116,567	$ 139,438	$ 130,536
Add (deduct):					
Capitalized interest	(3,924)	(3,676)	(2,401)	(2,942)	(298)
Total fixed charges above	78,847	78,731	76,940	75,292	77,396
Total earnings	$ 267,029	$ 237,402	$ 191,106	$ 211,788	$ 207,634
Ratio of earnings to fixed charges	3.39	3.02	2.48	2.81	2.68

Exhibit 21

AVISTA CORPORATION

SUBSIDIARIES OF REGISTRANT

Subsidiary	State or Country of Incorporation
Avista Capital, 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
Alaska Energy and Resources Company	Alaska
Alaska Electric Light and Power Company	Alaska
AJT Mining Properties, Inc.	Alaska
Snettisham Electric Company	Alaska
Salix, Inc.	Washington

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-33790, 333-126577 and 333-179042 on Form S-8 and in Registration Statement No. 333-187306 on Form S-3, relating to the consolidated financial statements of Avista Corporation and subsidiaries, 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, 2014.

/s/ Deloitte & Touche LLP

Seattle, Washington

February 25, 2015

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 25, 2015

/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 25, 2015

/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, 2014 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 25, 2015

/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