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

Form 10-Q

(Mark One)

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE QUARTERLY PERIOD ENDED June 30, 2016 OR

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

Commission file number 1-3701

AVISTA CORPORATION

(Exact name of Registrant as specified in its charter)

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

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

None

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

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

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

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

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

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

As of July 31, 2016, 63,706,037 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

AVISTA CORPORATION
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Forward-Looking Statements

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

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

These statements are based upon underlying assumptions (many of which are based, in turn, upon further assumptions). Such statements are made both in our reports filed under the Securities Exchange Act of 1934, as amended (including this Quarterly Report on Form 10-Q), and elsewhere. Forward-looking statements are all statements except those of historical fact including, without limitation, those that are identified by the use of words that include "will," "may," "could," "should," "intends," "plans," "seeks," "anticipates," "estimates," "expects," "forecasts," "projects," "predicts," and similar expressions.

Forward-looking statements (including those made in this Quarterly Report on Form 10-Q) are subject to a variety of risks, 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:

Financial Risk

- 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;
- 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;
- 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 to which we recover interest costs through retail rates collected from customers;
- 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;
- external pressure to meet financial goals that can lead to short-term or expedient decisions that reduce the likelihood of long-term objectives being met;
- deterioration in the creditworthiness of our customers;
- 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;
- 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;
- 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;

Utility Regulatory Risk

- state and federal regulatory decisions or related judicial 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, operating costs and commodity costs and discretion over allowed return on investment;
- possibility that our integrated resource plans for electric and natural gas will not be acknowledged by the state commissions;

Energy Commodity Risk

- 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 in wholesale energy transactions and credit risk to us from such transactions, and the market value of derivative assets and liabilities;
- default or nonperformance on the part of any parties from whom we purchase and/or sell capacity or energy;
- potential obsolescence of our power supply resources;

Operational Risk

- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, snow and ice storms, that can disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies and support services;
- explosions, fires, accidents, mechanical breakdowns or other incidents that may impair assets and may disrupt operations of any of our generation facilities, transmission and distribution systems or other operations and may require us to purchase replacement power;
- public injuries or damage arising from or allegedly arising from our operations;
- blackouts or disruptions of interconnected transmission systems (the regional power grid);
- 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;
- 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;
- increasing costs of insurance, more restrictive coverage terms and our ability to obtain insurance;
- delays or changes in construction costs, and/or our ability to obtain required permits and materials for present or prospective facilities;
- third party construction of buildings, billboard signs or towers within our rights of way, or placement of fuel receptacles within close proximity to our transformers or other equipment, including overbuild atop natural gas distribution lines;
- the loss of key suppliers for materials or services or disruptions to the supply chain;
- increasing health care costs and health insurance provided to our employees and retirees;
- adverse impacts to our Alaska operations that could result from an extended outage of its hydroelectric generating resources or its inability to deliver energy, due to its lack of interconnectivity to any other electrical grids and the extensive cost of replacement power (diesel);

Compliance Risk

- compliance with extensive federal, state and local legislation and regulation, including numerous environmental, health, safety, infrastructure protection, reliability and other laws and regulations that affect our operations and costs;
- the ability to comply with the terms of the licenses and permits for our hydroelectric or thermal generating facilities at cost-effective levels;

Technology Risk

- cyber attacks on us or our vendors 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;
- disruption to or breakdowns of information systems, automated controls and other technologies that we rely on for our operations, communications and customer service;
- changes in the costs to operate and maintain current production technology or to implement new information technology systems that impede our ability to complete such projects timely and effectively;
- changes in technologies, possibly making some of the current technology we utilize obsolete or the introduction of new technology that may create new cyber security related risk;
- insufficient technology skills, which could lead to the inability to develop, modify or maintain our information systems;

Strategic Risk

- growth or decline of our customer base and the extent to which new uses for our services may materialize or existing uses may decline, including, but not limited to, the effect of the trend toward distributed generation at customer sites;
- 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;
- 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 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;

External Mandates Risk

- changes in environmental laws, regulations, decisions and policies, including present and potential environmental remediation costs and our compliance with these matters;
- the potential effects of legislation or administrative rulemaking at the federal, state or local levels, 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 distribution systems through accelerated adoption of distributed generation or electric-powered transportation or 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;
- 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;
- failure to identify changes in legislation, taxation and regulatory issues which are detrimental or beneficial to our overall business; and
- the risk of municipalization in any of our service territories.

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

PART I. Financial Information

Item 1. Condensed Consolidated Financial Statements

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

Dollars in thousands, except per share amounts
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Operating Revenues:				
Utility revenues	$ 312,888	$ 330,830	$ 725,681	$ 767,237
Non-utility revenues	5,950	6,502	11,330	16,585
Total operating revenues	318,838	337,332	737,011	783,822
Operating Expenses:				
Utility operating expenses:				
Resource costs	109,815	141,116	271,534	350,676
Other operating expenses	78,666	73,112	154,445	146,284
Depreciation and amortization	39,678	35,676	78,870	69,976
Taxes other than income taxes	22,615	23,257	52,000	53,155
Non-utility operating expenses:				
Other operating expenses	6,281	6,646	12,106	16,462
Depreciation and amortization	192	165	380	334
Total operating expenses	257,247	279,972	569,335	636,887
Income from operations	61,591	57,360	167,676	146,935
Interest expense	21,318	19,866	42,591	39,768
Interest expense to affiliated trusts	154	115	292	227
Capitalized interest	(837)	(879)	(1,751)	(1,796)
Other income-net	(3,041)	(1,836)	(5,463)	(4,067)
Income from continuing operations before income taxes	43,997	40,094	132,007	112,803
Income tax expense	16,710	15,016	47,055	41,263
Net income from continuing operations	27,287	25,078	84,952	71,540
Net income from discontinued operations (Note 3)	—	196	—	196
Net income	27,287	25,274	84,952	71,736
Net income attributable to noncontrolling interests	(33)	(28)	(49)	(41)
Net income attributable to Avista Corp. shareholders	$ 27,254	$ 25,246	$ 84,903	$ 71,695

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (continued)

Avista Corporation

Dollars in thousands, except per share amounts
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Amounts attributable to Avista Corp. shareholders:				
Net income from continuing operations attributable to Avista Corp. shareholders	$ 27,254	$ 25,050	$ 84,903	$ 71,499
Net income from discontinued operations attributable to Avista Corp. shareholders	—	196	—	196
Net income attributable to Avista Corp. shareholders	$ 27,254	$ 25,246	$ 84,903	$ 71,695
Weighted-average common shares outstanding (thousands), basic	63,386	62,281	62,995	62,299
Weighted-average common shares outstanding (thousands), diluted	63,783	62,600	63,368	62,744
Earnings per common share attributable to Avista Corp. shareholders, basic:				
Earnings per common share from continuing operations	$ 0.43	$ 0.41	$ 1.35	$ 1.15
Earnings per common share from discontinued operations	—	—	—	—
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 0.43	$ 0.41	$ 1.35	$ 1.15
Earnings per common share attributable to Avista Corp. shareholders, diluted:				
Earnings per common share from continuing operations	$ 0.43	$ 0.40	$ 1.34	$ 1.14
Earnings per common share from discontinued operations	—	—	—	—
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 0.43	$ 0.40	$ 1.34	$ 1.14
Dividends declared per common share	$ 0.3425	$ 0.3300	$ 0.6850	$ 0.6600

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

Dollars in thousands
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Net income	$ 27,287	$ 25,274	$ 84,952	$ 71,736
Other Comprehensive Income (Loss):				
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $76, $132, $(587) and $264 respectively	140	245	(1,089)	491
Total other comprehensive income (loss)	140	245	(1,089)	491
Comprehensive income	27,427	25,519	83,863	72,227
Comprehensive income attributable to noncontrolling interests	(33)	(28)	(49)	(41)
Comprehensive income attributable to Avista Corporation shareholders	$ 27,394	$ 25,491	$ 83,814	$ 72,186

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands
(Unaudited)

	June 30, 2016	December 31, 2015
Assets:		
Current Assets:		
Cash and cash equivalents	$ 13,522	$ 10,484
Accounts and notes receivable-less allowances of $4,507 and $4,530, respectively	121,277	169,413
Utility energy commodity derivative assets	1,730	683
Regulatory asset for utility derivatives	15,194	17,260
Materials and supplies, fuel stock and stored natural gas	51,639	54,148
Income taxes receivable	25,571	24,121
Other current assets	39,786	29,937
Total current assets	268,719	306,046
Net Utility Property:		
Utility plant in service	5,303,883	5,129,192
Construction work in progress	187,946	202,683
Total	5,491,829	5,331,875
Less: Accumulated depreciation and amortization	1,501,130	1,433,286
Total net utility property	3,990,699	3,898,589
Other Non-current Assets:		
Investment in exchange power-net	7,758	8,983
Investment in affiliated trusts	11,547	11,547
Goodwill	57,672	57,672
Long-term energy contract receivable	7,502	14,694
Other property and investments-net and other non-current assets	64,343	50,750
Total other non-current assets	148,822	143,646
Deferred Charges:		
Regulatory assets for deferred income tax	99,325	101,240
Regulatory assets for pensions and other postretirement benefits	226,737	235,009
Other regulatory assets	111,488	99,798
Regulatory asset for unsettled interest rate swaps	191,959	83,973
Non-current regulatory asset for utility commodity derivatives	24,598	32,420
Other deferred charges	6,674	5,928
Total deferred charges	660,781	558,368
Total assets	$ 5,069,021	$ 4,906,649

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

Dollars in thousands
(Unaudited)

	June 30, 2016	December 31, 2015
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 63,056	$ 114,349
Current portion of long-term debt and capital leases	93,227	93,167
Short-term borrowings	160,000	105,000
Utility energy commodity derivative liabilities	7,981	14,268
Other current liabilities	177,450	147,896
Total current liabilities	501,714	474,680
Long-term debt and capital leases	1,479,668	1,480,111
Long-term debt to affiliated trusts	51,547	51,547
Regulatory liability for utility plant retirement costs	267,918	261,594
Pensions and other postretirement benefits	202,063	201,453
Deferred income taxes	783,955	747,477
Other non-current liabilities and deferred credits	165,419	161,500
Total liabilities	3,452,284	3,378,362
Commitments and Contingencies (See Notes to Condensed Consolidated Financial Statements)		
Equity:		
Avista Corporation Shareholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 63,704,295 and 62,312,651 shares issued and outstanding as of June 30, 2016 and December 31, 2015, respectively	1,052,190	1,004,336
Accumulated other comprehensive loss	(7,739)	(6,650)
Retained earnings	572,576	530,940
Total Avista Corporation shareholders' equity	1,617,027	1,528,626
Noncontrolling Interests	(290)	(339)
Total equity	1,616,737	1,528,287
Total liabilities and equity	$ 5,069,021	$ 4,906,649

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

For the Six Months Ended June 30
Dollars in thousands
(Unaudited)

	2016	2015
Operating Activities:		
Net income	$ 84,952	$ 71,736
Non-cash items included in net income:		
Depreciation and amortization	81,071	72,131
Deferred income tax provision and investment tax credits	56,652	6,161
Power and natural gas cost amortizations, net	9,958	11,414
Amortization of debt expense	1,742	1,774
Amortization of investment in exchange power	1,225	1,225
Stock-based compensation expense	4,236	3,441
Equity-related AFUDC	(4,368)	(3,874)
Pension and other postretirement benefit expense	19,315	18,786
Amortization of Spokane Energy contract	7,192	6,612
Gain on sale of Ecova	—	(163)
Decoupling regulatory deferral	(24,787)	(6,813)
Other	(8,137)	1,597
Contributions to defined benefit pension plan	(8,000)	(8,000)
Changes in certain current assets and liabilities:		
Accounts and notes receivable	50,062	25,460
Materials and supplies, fuel stock and stored natural gas	2,510	15,484
Increase in collateral posted for derivative instruments	(83,499)	(908)
Income taxes receivable	(1,450)	42,951
Other current assets	(4,436)	2,609
Accounts payable	(31,484)	(26,396)
Income taxes payable	860	1,055
Other current liabilities	2,337	(4,170)
Net cash provided by operating activities	155,951	232,112
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(182,815)	(177,752)
Other capital expenditures	(165)	(504)
Cash paid in acquisition, net	—	(95)
Proceeds from sale of Ecova, net of cash sold	—	1,022
Other	(23,644)	1,740
Net cash used in investing activities	(206,624)	(175,589)

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

For the Six Months Ended June 30
Dollars in thousands
(Unaudited)

	2016	2015
Financing Activities:		
Net increase (decrease) in short-term borrowings	$ 55,000	$ (15,000)
Redemption and maturity of long-term debt	(1,583)	(1,414)
Maturity of nonrecourse long-term debt of Spokane Energy	—	(1,431)
Issuance of common stock, net of issuance costs	47,173	1,080
Repurchase of common stock	—	(2,920)
Cash dividends paid	(43,267)	(41,268)
Other	(3,612)	(1,471)
Net cash provided by (used in) financing activities	53,711	(62,424)
Net increase (decrease) in cash and cash equivalents	3,038	(5,901)
Cash and cash equivalents at beginning of period	10,484	22,143
Cash and cash equivalents at end of period	$ 13,522	$ 16,242

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

Avista Corporation

For the Six Months Ended June 30
Dollars in thousands
(Unaudited)

	2016	2015
Common Stock, Shares:		
Shares outstanding at beginning of period	62,312,651	62,243,374
Shares issued	1,391,644	139,962
Shares repurchased	—	(89,400)
Shares outstanding at end of period	63,704,295	62,293,936
Common Stock, Amount:		
Balance at beginning of period	$ 1,004,336	$ 999,960
Equity compensation expense	3,708	3,081
Issuance of common stock, net of issuance costs	47,173	1,080
Payment of minimum tax withholdings for share-based payment awards	(3,027)	(1,480)
Repurchase of common stock	—	(1,431)
Excess tax benefits	—	43
Balance at end of period	1,052,190	1,001,253
Accumulated Other Comprehensive Loss:		
Balance at beginning of period	(6,650)	(7,888)
Other comprehensive income (loss)	(1,089)	491
Balance at end of period	(7,739)	(7,397)
Retained Earnings:		
Balance at beginning of period	530,940	491,599
Net income attributable to Avista Corporation shareholders	84,903	71,695
Cash dividends paid (common stock)	(43,267)	(41,268)
Repurchase of common stock	—	(1,489)
Balance at end of period	572,576	520,537
Total Avista Corporation shareholders’ equity	1,617,027	1,514,393
Noncontrolling Interests:		
Balance at beginning of period	(339)	(429)
Net income attributable to noncontrolling interests	49	41
Balance at end of period	(290)	(388)
Total equity	$ 1,616,737	$ 1,514,005

The Accompanying Notes are an Integral Part of These Statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

The accompanying condensed consolidated financial statements of Avista Corporation (Avista Corp. or the Company) for the interim periods ended June 30, 2016 and 2015 are unaudited; however, in the opinion of management, the statements reflect all adjustments necessary for a fair statement of the results for the interim periods. The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. The Condensed Consolidated Statements of Income for the interim periods are not necessarily indicative of the results to be expected for the full year. These condensed consolidated financial statements do not contain the detail or footnote disclosure concerning accounting policies and other matters which would be included in full fiscal year consolidated financial statements; therefore, they should be read in conjunction with the Company's audited consolidated financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2015 (2015 Form 10-K). Please refer to the section “Acronyms and Terms” in the 2015 Form 10-K for definitions of terms. The acronyms and terms are an integral part of these condensed consolidated financial statements.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corp. is 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.

Alaska Energy and Resources Company (AERC) is a wholly-owned subsidiary of Avista Corp. The primary subsidiary of AERC is Alaska Electric Light and Power Company (AEL&P), comprising Avista Corp.'s regulated utility operations in Alaska. Avista Capital, Inc. (Avista Capital), a wholly owned non-regulated subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility businesses, with the exception of AJT Mining Properties, Inc. in Alaska.

Basis of Reporting

The condensed 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. Intercompany balances were eliminated in consolidation. The accompanying condensed consolidated financial statements include the Company’s proportionate share of utility plant and related operations resulting from its interests in jointly owned plants.

Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on 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. Taxes other than income taxes consisted of the following items for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Utility related taxes	$ 12,573	$ 12,941	$ 30,938	$ 32,439
Property taxes	9,290	9,535	19,710	19,221
Other taxes	752	781	1,352	1,495
Total	$ 22,615	$ 23,257	$ 52,000	$ 53,155

Materials and Supplies, Fuel Stock and Stored Natural Gas

Inventories of materials and supplies, fuel stock and stored natural gas are recorded at average cost for our regulated operations and the lower of cost or net realizable value for our non-regulated operations and consisted of the following as of June 30, 2016 and December 31, 2015 (dollars in thousands):

	June 30, 2016	December 31, 2015
Materials and supplies	$ 38,037	$ 37,101
Fuel stock	5,800	4,273
Stored natural gas	7,802	12,774
Total	$ 51,639	$ 54,148

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Condensed Consolidated Balance Sheets measured at estimated fair value.

The Washington Utilities and Transportation Commission (UTC) and the Idaho Public Utilities Commission (IPUC) issued accounting orders authorizing Avista Corp. 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 Corp. to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Condensed Consolidated Statements of Income. Realized gains or losses are recognized in the periods of delivery, subject to approval for recovery through retail rates. Realized gains and losses, result in adjustments to retail rates through purchased gas cost adjustments, the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rates cases. Regulatory assets are assessed regularly and are probable for recovery through future rates.

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

For interest rate swap derivatives, each period Avista Corp. 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. 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. While the Company has not received any formal accounting orders from the various state commissions providing for the offset of interest rate swap assets and liabilities with regulatory assets and liabilities, the interest rate swap derivatives are risk management tools similar to energy commodity derivatives and the Company believes that the prior practice of the commissions to provide recovery through the ratemaking process justifies this accounting treatment.

As of June 30, 2016, the Company has multiple master netting agreements with a variety of entities that allow for cross-commodity netting of derivative agreements with the same counterparty (i.e. power derivatives can be netted with natural gas derivatives) under Accounting Standards Codification (ASC) 815-10-45. In addition, some master netting agreements allow for the netting of commodity derivatives and interest rate swap derivatives for the same counterparty. The Company does not have any agreements which allow for cross-affiliate netting among multiple affiliated legal entities. The Company nets all derivative instruments when allowed by the agreement for presentation in the Condensed Consolidated Balance Sheets.

Fair Value Measurements

Fair value represents the price that would be received when selling 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, deferred compensation assets, as well as derivatives related to interest rate swap derivatives and foreign currency exchange derivatives, are reported at estimated fair value on the Condensed Consolidated Balance Sheets. See Note 8 for the Company’s fair value disclosures.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax, consisted of the following as of June 30, 2016 and December 31, 2015 (dollars in thousands):

	June 30, 2016	December 31, 2015
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $4,167 and $3,580, respectively	$ 7,739	$ 6,650

The following table details the reclassifications out of accumulated other comprehensive loss by component for the three and six months ended June 30 (dollars in thousands). Items in parenthesis indicate reductions to net income.

	Amounts Reclassified from Accumulated Other Comprehensive Loss				
	Three months ended June 30,		Six months ended June 30,		
Details about Accumulated Other Comprehensive Loss Components	2016	2015	2016	2015	Affected Line Item in Statement of Income
Amortization of defined benefit pension items					
Amortization of net prior service cost	$ (311)	$ (273)	$ (622)	$ (546)	(a)
Amortization of net loss	3,642	3,687	$ 7,284	$ 7,375	(a)
Adjustment due to effects of regulation	(3,115)	(3,037)	(8,338)	(6,074)	(a) (b)
	216	377	(1,676)	755	Total before tax
	(76)	(132)	587	(264)	Tax benefit (expense)
	$ 140	$ 245	$ (1,089)	$ 491	Net of tax

(a) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 5 for additional details).

(b) The adjustment for the effects of regulation during the six months ended June 30, 2016 includes approximately $2.1 million related to the reclassification of a pension regulatory asset associated with one of our jurisdictions into accumulated other comprehensive loss.

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses losses that do not meet these conditions for accrual if there is a reasonable possibility that a loss may be incurred. As of June 30, 2016, the Company has not recorded any significant amounts related to unresolved contingencies.

NOTE 2. NEW ACCOUNTING STANDARDS

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (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 was originally effective for periods beginning after December 15, 2016 and early adoption is not permitted. In August 2015, the FASB issued ASU 2015-14, "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," which deferred the effective date of ASU 2014-09 for one year, with adoption as of the original date permitted. However, while this ASU is not effective until 2018, it may require retroactive application to all periods presented in the financial statements. As such, at adoption, amounts from the two preceding years 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 on its future financial condition, results of operations and cash flows.

In February 2015, the FASB issued ASU No. 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis." This ASU changes the consolidation analysis required under GAAP, including the identification of variable interest entities (VIE). The ASU also removes the deferral of the VIE analysis related to investments in certain investment funds, which results in a different consolidation evaluation for these types of investments. The Company adopted this standard effective January 1, 2016. The adoption of this standard resulted in the identification of several Avista Corp. investments in limited partnerships (or a functional equivalent) that are now considered VIEs under the new standard. Consolidation of these VIEs by Avista Corp. is not required because the Company does not have majority ownership in any of the entities, it does not have the power to direct any activities of the entities and it does not have the power to appoint executive leadership (including the board of directors). Avista Corp.'s total investment in these entities is not material and it does not have any additional commitments to these VIEs beyond the initial investment.

In February 2016, the FASB issued ASU No. 2016-02 "Leases (Topic 842)." This ASU introduces a new lessee model that brings most leases onto the balance sheet. The standard also aligns certain of the underlying principles of the new lessor model with those in Topic 606, the FASB's new revenue recognition standard. Furthermore, this ASU addresses other concerns related to the current leases model; for example, eliminating the required use of bright-line tests in current GAAP for determining lease classification (operating leases versus capital leases). This ASU also includes enhanced disclosures surrounding leases. This ASU is effective for periods beginning on or after December 15, 2018; however, early adoption is permitted. Upon adoption, this ASU must be applied using a modified retrospective approach. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. The Company evaluated this standard and determined that it will not early adopt this standard as of June 30, 2016. The Company is evaluating this standard and cannot, at this time, estimate the potential impact on its future financial condition, results of operations and cash flows.

In March 2016, the FASB issued ASU 2016-09 "Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting." This ASU simplifies several aspects of the accounting for employee share-based payment transactions including:

- allowing excess tax benefits or tax deficiencies to be recognized as income tax benefits or expenses in the Statements of Income rather than in Additional Paid in Capital (APIC),
- excess tax benefits no longer represent a financing cash inflow on the Statements of Cash Flows and instead will be included as an operating activity,
- excess tax benefits and tax deficiencies will be excluded from the calculation of diluted earnings per share, whereas under current accounting guidance, these amounts must be estimated and included in the calculation,
- allowing forfeitures to be accounted for as they occur, instead of estimating forfeitures, and
- changing the statutory tax withholding requirements for share-based payments.

This ASU is effective for periods beginning after December 15, 2016 and early adoption is permitted. The Company early adopted this standard during the second quarter of 2016, with a retrospective effective date of January 1, 2016. Because this standard was adopted in the second quarter of 2016, but has a retrospective effective date of January 1, 2016, the effects from the adoption on 2016 results appear in the six months ended June 30, 2016, but are not included in the second quarter of 2016. The adoption of this standard resulted in a recognized income tax benefit of $1.6 million in 2016 associated with excess tax benefits on settled share-based employee payments. In all future reports which include the first quarter of 2016, the results for that quarter will be restated to include the effects of the excess tax benefits recognized. Periods prior to 2016 were not restated for the adoption of this accounting standard as the Company has adopted this standard on a prospective basis beginning January 1, 2016.

NOTE 3. DISCONTINUED OPERATIONS

On June 30, 2014, Avista Capital, completed the sale of 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 price was $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 has not had and will not have any 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, option holders and a warrant holder, pro rata based on ownership. A portion of the proceeds from the transaction was held in escrow for 15 months from the closing of the transaction to satisfy certain indemnification obligations under the merger agreement (Escrow) and there was also a portion withheld pending resolution of adjustments to working capital.

No claims were made against the Escrow and all Escrow amounts were released in October 2015 and the Company received its full portion of the Escrow proceeds together with the remainder of the working capital adjustment escrow for a total amount of $13.8 million. After consideration of all escrow amounts received, the sales transaction provided cash proceeds to Avista Corp., net of debt, payment to option and minority holders, income taxes and transaction expenses, of $143.7 million and resulted in a net gain of $74.8 million. Almost all of the net gain was recognized in 2014 with some true-ups during 2015.

Prior to the completion of the sales transaction, Ecova was a reportable business segment. The following table presents amounts that were included in discontinued operations for the three and six months ended June 30, 2015 (there were no amounts recorded in 2016) (dollars in thousands):

	Three months ended June 30, 2015:	Six months ended June 30, 2015:
Gain on sale of Ecova (1)	$ 163	$ 163
Income before income taxes	163	163
Income tax benefit (2)	(33)	(33)
Net income from discontinued operations attributable to Avista Corp. shareholders	$ 196	$ 196

(1) The gain recognized during the second quarter of 2015 related to the resolution of the working capital adjustment and the release of the associated escrow funds.

(2) The tax benefit in the second quarter of 2015 resulted from a state tax true-up, partially offset by tax expense associated with the gain on sale recognized during the second quarter of 2015.

NOTE 4. DERIVATIVES AND RISK MANAGEMENT

The disclosures below in Note 4 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.

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 a portion of the related financial risks. These transactions range from terms of intra-hour up to multiple years.

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 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.

The Company is required to plan for sufficient natural gas delivery capacity to serve its retail customers for a theoretical peak day event, the Company generally has more pipeline and storage capacity than what is needed during periods other than a peak day. The Company optimizes its natural gas resources by using market opportunities to generate economic value that helps mitigate fixed costs. Avista Utilities also optimizes its natural gas storage capacity by purchasing and storing natural gas when prices are traditionally lower, typically in the summer, and withdrawing during higher priced months, typically during the winter. However, if market conditions and prices indicate that the Company should buy or sell natural gas during other times in the year, the Company engages in optimization transactions to capture value in the marketplace. Natural gas 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.

The following table presents the underlying energy commodity derivative volumes as of June 30, 2016 that are expected to be delivered 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
2016	186	1,360	12,096	95,043	200	1,665	1,395	69,463
2017	403	97	1,265	78,600	255	881	1,360	51,135
2018	397	—	—	27,553	286	192	1,360	9,093
2019	235	—	610	10,245	158	—	1,345	—
2020	—	—	910	1,815	—	—	1,430	—
Thereafter	—	—	—	—	—	—	1,060	—

The following table presents the underlying energy commodity derivative volumes as of December 31, 2015 that are expected to be delivered 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
2016	407	1,954	17,252	142,693	280	2,656	3,182	112,233
2017	397	97	675	49,200	255	483	1,360	26,965
2018	397	—	—	15,118	286	—	1,360	2,738
2019	235	—	305	6,935	158	—	1,345	—
2020	—	—	455	905	—	—	1,430	—
Thereafter	—	—	—	—	—	—	1,060	—

(1) Physical transactions represent commodity transactions in which Avista Utilities will take or make delivery of either electricity or natural gas; financial transactions represent derivative instruments with delivery of cash in the amount of the benefit or cost but with no physical delivery of the commodity, such as futures, swaps, options, or forward contracts.

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 delivered and will be included in the various recovery mechanisms (ERM, PCA, and Purchased Gas Adjustments (PGA)), or in the general rate case process, and are expected to be collected through retail rates from customers.

Foreign Currency Exchange Derivatives

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 derivatives when such commodity transactions are initiated. The foreign currency exchange derivatives and the unhedged foreign currency risk have 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 are included with natural gas supply costs for ratemaking.

The following table summarizes the foreign currency derivatives that the Company has outstanding as of June 30, 2016 and December 31, 2015 (dollars in thousands):

	June 30, 2016	December 31, 2015
Number of contracts	25	24
Notional amount (in United States currency)	$ 4,427	$ 1,463
Notional amount (in Canadian currency)	5,699	2,002

Interest Rate Derivatives

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt, and future borrowing requirements. The Company 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 outstanding unsettled interest rate swaps as of June 30, 2016 and December 31, 2015 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
June 30, 2016	6	$ 115,000	2016
	4	55,000	2017
	13	265,000	2018
	4	50,000	2019
	1	10,000	2020
	5	60,000	2022
December 31, 2015	6	$ 115,000	2016
	3	45,000	2017
	11	245,000	2018
	2	30,000	2019
	1	20,000	2022

The fair value of outstanding interest rate swaps can vary significantly from period to period depending on the total notional amount of swaps outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. 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

The amounts recorded on the Condensed Consolidated Balance Sheet as of June 30, 2016 and December 31, 2015 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 Condensed Consolidated Balance Sheet as of June 30, 2016 (in thousands):

	Fair Value as of June 30, 2016			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netted	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Other current liabilities	$ 11	$ (34)	$ —	$ (23)
Interest rate swap derivatives				
Other current liabilities	—	(49,244)	16,402	(32,842)
Other non-current liabilities and deferred credits	187	(142,902)	100,598	(42,117)
Energy commodity derivatives				
Current utility energy commodity derivative assets	2,389	(659)	—	1,730
Current utility energy commodity derivative liabilities	43,089	(60,018)	8,948	(7,981)
Other non-current liabilities and deferred credits	6,712	(31,310)	9,876	(14,722)
Total derivative instruments recorded on the balance sheet	$ 52,388	$ (284,167)	$ 135,824	$ (95,955)

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of December 31, 2015 (in thousands):

	Fair Value as of December 31, 2015			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netted	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Other current liabilities	$ 2	$ (19)	$ —	$ (17)
Interest rate swap derivatives				
Other property and investments-net and other non-current assets	23	—	—	23
Other current liabilities	118	(23,262)	3,880	(19,264)
Other non-current liabilities and deferred credits	1,407	(62,236)	30,150	(30,679)
Energy commodity derivatives				
Current utility energy commodity derivative assets	1,236	(553)	—	683
Current utility energy commodity derivative liabilities	67,466	(85,409)	3,675	(14,268)
Other non-current liabilities and deferred credits	6,613	(39,033)	10,851	(21,569)
Total derivative instruments recorded on the balance sheet	$ 76,865	$ (210,512)	$ 48,556	$ (85,091)

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.

The following table presents the Company's collateral outstanding related to its derivative instruments as of June 30, 2016 and December 31, 2015 (in thousands):

	June 30, 2016	December 31, 2015
Energy commodity derivatives		
Cash collateral posted	$ 29,245	$ 28,716
Letters of credit outstanding	17,500	28,200
Balance sheet offsetting (cash collateral against net derivative positions)	18,824	14,526
Interest rate swap derivatives		
Cash collateral posted	117,000	34,030
Letters of credit outstanding	22,000	9,600
Balance sheet offsetting (cash collateral against net derivative positions)	117,000	34,030

There was no cash collateral or letters of credit outstanding as of June 30, 2016 and December 31, 2015 related to foreign currency exchange derivatives.

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 following table presents the aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position and the amount of additional collateral the Company could be required to post as of June 30, 2016 and December 31, 2015 (in thousands):

	June 30, 2016	December 31, 2015
Energy commodity derivatives		
Liabilities with credit-risk-related contingent features	$ 1,142	$ 7,090
Additional collateral to post	1,088	6,980
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	192,146	85,498
Additional collateral to post	18,520	18,750

NOTE 5. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

Avista Utilities

The Company's pension and other postretirement plans have not changed during the six months ended June 30, 2016. 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 $8.0 million in cash to the pension plan for the six months ended June 30, 2016 and expects to contribute $12.0 million total in 2016. The Company contributed $12.0 million in cash to the pension plan in 2015.

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

	Pension Benefits		Other Post-retirement Benefits	
	2016	2015	2016	2015
Three months ended June 30:				
Service cost	$ 4,569	$ 4,984	$ 804	$ 721
Interest cost	6,900	6,531	1,534	1,292
Expected return on plan assets	(6,875)	(7,075)	(475)	(500)
Amortization of prior service cost	—	6	(312)	(287)
Net loss recognition	2,201	2,634	1,494	1,263
Net periodic benefit cost	$ 6,795	$ 7,080	$ 3,045	$ 2,489
Six months ended June 30:				
Service cost	$ 9,088	$ 9,933	$ 1,583	$ 1,420
Interest cost	13,800	13,203	3,093	2,623
Expected return on plan assets	(13,625)	(14,491)	(950)	(931)
Amortization of prior service cost	—	12	(624)	(566)
Net loss recognition	4,091	5,028	2,859	2,555
Net periodic benefit cost	$ 13,354	$ 13,685	$ 5,961	$ 5,101

NOTE 6. 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. A two-year option was exercised by the Company in May 2016 to extend the maturity of the facility agreement to April 2021.

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 June 30, 2016 and December 31, 2015 (dollars in thousands):

	June 30, 2016	December 31, 2015
Borrowings outstanding at end of period	$ 160,000	$ 105,000
Letters of credit outstanding at end of period	$ 45,795	$ 44,595
Average interest rate on borrowings at end of period	1.22%	1.18%

AEL&P

AEL&P has a committed line of credit in the amount of $25.0 million that expires in November 2019. As of June 30, 2016 and December 31, 2015, there were no borrowings or letters of credit outstanding under this committed line of credit.

NOTE 7. 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 six months ended June 30, 2016 and the year ended December 31, 2015:

	June 30, 2016	December 31, 2015
Low distribution rate	1.29%	1.11%
High distribution rate	1.55%	1.29%
Distribution rate at the end of the period	1.55%	1.29%

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 Condensed Consolidated Balance Sheets as of June 30, 2016 and December 31, 2015. Interest expense to affiliated trusts in the Condensed Consolidated Statements of Income represents interest expense on these debentures.

NOTE 8. 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) and long-term debt to affiliated trusts are reported at carrying value on the Condensed 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 Condensed Consolidated Balance Sheets as of June 30, 2016 and December 31, 2015 (dollars in thousands):

	June 30, 2016		December 31, 2015	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 951,000	$ 1,098,661	$ 951,000	$ 1,055,797
Long-term debt (Level 3)	592,000	664,467	592,000	595,018
Snettisham capital lease obligation (Level 3)	63,308	65,708	64,455	63,150
Long-term debt to affiliated trusts (Level 3)	51,547	37,114	51,547	36,083

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 72.00 to 133.81, where a par value of 100.0 represents the carrying value recorded on the Condensed Consolidated Balance Sheets. Level 2 long-term debt represents publicly issued bonds with quoted market prices; however, due to their limited trading activity, they are classified as Level 2 because brokers must generate quotes and make estimates if there is no trading activity near a period end. Level 3 long-term debt consists of private placement bonds and debt to affiliated trusts, which typically have no secondary trading activity. Fair values in Level 3 are estimated based on market prices from third party brokers using secondary market quotes for debt with similar risk and terms to generate quotes for Avista Corp. bonds. Due to 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 Snettisham capital lease obligation was discounted to present value using the Moody's Aaa Corporate discount rate as published by the Federal Reserve on June 30, 2016.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Condensed Consolidated Balance Sheets as of June 30, 2016 and December 31, 2015 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
June 30, 2016					
Assets:					
Energy commodity derivatives	$ —	$ 52,178	$ —	$ (50,448)	$ 1,730
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	12	(12)	—
Foreign currency derivatives	—	11	—	(11)	—
Interest rate swaps	—	187	—	(187)	—
Deferred compensation assets:					
Fixed income securities (2)	1,896	—	—	—	1,896
Equity securities (2)	5,461	—	—	—	5,461
Total	$ 7,357	$ 52,376	$ 12	$ (50,658)	$ 9,087
Liabilities:					
Energy commodity derivatives	$ —	$ 70,399	$ —	$ (69,272)	$ 1,127
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	6,869	(12)	6,857
Power exchange agreement	—	—	14,614	—	14,614
Power option agreement	—	—	105	—	105
Foreign currency derivatives	—	34	—	(11)	23
Interest rate swaps	—	192,146	—	(117,187)	74,959
Total	$ —	$ 262,579	$ 21,588	$ (186,482)	$ 97,685

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2015					
Assets:					
Energy commodity derivatives	$ —	$ 74,637	$ —	$ (73,954)	$ 683
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	678	(678)	—
Foreign currency derivatives	—	2	—	(2)	—
Interest rate swaps	—	1,548	—	—	1,548
Deferred compensation assets:					
Fixed income securities (2)	1,727	—	—	—	1,727
Equity securities (2)	5,761	—	—	—	5,761
Total	$ 7,488	$ 76,187	$ 678	$ (74,634)	$ 9,719
Liabilities:					
Energy commodity derivatives	$ —	$ 97,193	$ —	$ (88,480)	$ 8,713
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	5,717	(678)	5,039
Power exchange agreement	—	—	21,961	—	21,961
Power option agreement	—	—	124	—	124
Foreign currency derivatives	—	19	—	(2)	17
Interest rate swaps	—	85,498	—	—	85,498
Total	$ —	$ 182,710	$ 27,802	$ (89,160)	$ 121,352

(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 and other non-current assets on the Condensed Consolidated Balance Sheets.

The difference between the amount of derivative assets and liabilities disclosed in respective levels in the table above and the amount of derivative assets and liabilities disclosed on the Condensed Consolidated Balance Sheets is due to netting arrangements with certain counterparties.

To establish fair value for commodity derivatives, 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 market 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 market quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

To establish fair values for interest rate swaps, the Company uses forward market curves for interest rates for the term of the swaps and discounts the cash flows back to present value using an appropriate discount rate. The discount rate is calculated by third party brokers according to the terms of the swap derivatives and evaluated by the Company for reasonableness, with consideration given to the potential non-performance risk by the Company. Future cash flows of the interest rate swaps are equal to the fixed interest rate in the swap compared to the floating market interest rate multiplied by the notional amount for each period.

To establish fair value for foreign currency derivatives, the Company uses forward market curves for Canadian dollars against the US dollar and multiplies the difference between the locked-in price and the market price by the notional amount of the derivative. Forward foreign currency market curves are provided by third party brokers. The Company's credit spread is factored into the locked-in price of the foreign exchange contracts.

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 $0.5 million as of June 30, 2016 and $0.6 million as of December 31, 2015.

Level 3 Fair Value

Under the power exchange agreement the Company purchases power at a price that is based on the average operating and maintenance (O&M) charges from three surrogate nuclear power plants around the country. To estimate the fair value of this agreement the Company estimates the difference between the purchase price based on the future O&M charges and forward prices for energy. 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 O&M charges from the three surrogate nuclear power plants 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, and 3) volatility rates for periods beyond June 2018. 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 June 30, 2016 (dollars in thousands):

	Fair Value (Net) at June 30, 2016	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (14,614)	Surrogate facility pricing	O&M charges	$34.91-$49.15/MWh (1)
			Escalation factor	3% - 2017 to 2019
			Transaction volumes	396,984 - 406,909 MWhs
Power option agreement	$ (105)	Black-Scholes-Merton	Strike price	$41.81/MWh - 2018
				$52.59/MWh - 2017
			Delivery volumes	128,403 - 285,979 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreement	$ (6,857)	Internally derived weighted average cost of gas	Forward purchase prices	$2.10 - $2.77/mmBTU
			Forward sales prices	$2.21 - $3.68/mmBTU
			Purchase volumes	115,000 - 310,000 mmBTUs
			Sales volumes	60,000 - 310,000 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2016 are $39.22 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 2016 are $44.33 for Washington and $39.22 for Idaho.

(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.37 for 2016 to 0.26 in June 2018.

The valuation methods, significant inputs and resulting fair values described above were developed by the Company's management and are reviewed on at least a quarterly basis 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 three and six months ended June 30 (dollars in thousands):

	Natural Gas Exchange Agreement	Power Exchange Agreement	Power Option Agreement	Total
Three months ended June 30, 2016:				
Balance as of April 1, 2016	$ (6,006)	$ (20,193)	$ (97)	$ (26,296)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	(1,551)	4,400	(8)	2,841
Settlements	700	1,179	—	1,879
Ending balance as of June 30, 2016 (2)	$ (6,857)	$ (14,614)	$ (105)	$ (21,576)
Three months ended June 30, 2015:				
Balance as of April 1, 2015	$ 817	$ (25,903)	$ (251)	$ (25,337)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	(8,163)	6,551	106	(1,506)
Settlements	521	736	—	1,257
Ending balance as of June 30, 2015 (2)	$ (6,825)	$ (18,616)	$ (145)	$ (25,586)
Six months ended June 30, 2016:				
Balance as of January 1, 2016	$ (5,039)	$ (21,961)	$ (124)	$ (27,124)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	(3,296)	1,968	19	(1,309)
Settlements	1,478	5,379	—	6,857
Ending balance as of June 30, 2016 (2)	$ (6,857)	$ (14,614)	$ (105)	$ (21,576)
Six months ended June 30, 2015:				
Balance as of January 1, 2015	$ (35)	$ (23,299)	$ (424)	$ (23,758)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	(7,386)	170	279	(6,937)
Settlements	596	4,513	—	5,109
Ending balance as of June 30, 2015 (2)	$ (6,825)	$ (18,616)	$ (145)	$ (25,586)

(1) All gains and losses are included in other regulatory assets and liabilities. There were no gains and losses included in either net income or other comprehensive income during any of the periods presented in the table above.
(2) There were no purchases, issuances or transfers from other categories of any derivatives instruments during the periods presented in the table above.

NOTE 9. COMMON STOCK

In March 2016, the Company entered into four separate sales agency agreements under which the sales agents, as Avista Corp.'s agents, may offer and sell up to 3.8 million new shares of Avista Corp.'s common stock, no par value, from time to time. The sales agency agreements expire on February 29, 2020. As of June 30, 2016, 1.2 million shares have been issued under these agreements resulting in total net proceeds of $46.3 million, leaving 2.6 million shares remaining to be issued.

In the six months ended June 30, 2016, Avista Corp. also issued $0.9 million of common stock in share-based compensation.

NOTE 10. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORP. SHAREHOLDERS

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corp. shareholders for the three and six months ended June 30 (in thousands, except per share amounts):

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Numerator:				
Net income from continuing operations attributable to Avista Corp. shareholders	$ 27,254	$ 25,050	$ 84,903	$ 71,499
Net income from discontinued operations attributable to Avista Corp. shareholders	—	196	—	196
Denominator:				
Weighted-average number of common shares outstanding-basic	63,386	62,281	62,995	62,299
Effect of dilutive securities:				
Performance and restricted stock awards	397	319	373	445
Weighted-average number of common shares outstanding-diluted	63,783	62,600	63,368	62,744
Earnings per common share attributable to Avista Corp. shareholders, basic:				
Earnings per common share from continuing operations	$ 0.43	$ 0.41	$ 1.35	$ 1.15
Earnings per common share from discontinued operations	$ —	$ —	$ —	$ —
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 0.43	$ 0.41	$ 1.35	$ 1.15
Earnings per common share attributable to Avista Corp. shareholders, diluted:				
Earnings per common share from continuing operations	$ 0.43	$ 0.40	$ 1.34	$ 1.14
Earnings per common share from discontinued operations	$ —	$ —	$ —	$ —
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 0.43	$ 0.40	$ 1.34	$ 1.14

There were no shares excluded from the calculation because they were antidilutive.

NOTE 11. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For all such matters, the Company intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista Utilities’ or AEL&P's operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

California Refund Proceeding

In February 2016, APX, a market maker in the California Refund Proceedings in whose markets Avista Energy participated in the summer of 2000, asserted that Avista Energy and its other customer/participants may be responsible for a share of the disgorgement penalty APX may be found to owe to the California parties. The penalty arises as a result of the Federal Energy and Regulatory Commission's (FERC) finding that APX committed violations in the California market in the summer of 2000. APX is making these assertions despite Avista Energy having been dismissed in FERC Opinion No. 536 from the on-going administrative proceeding at the FERC regarding potential wrongdoing in the California markets in the summer of 2000. APX has identified Avista Energy’s share of APX’s exposure to be as much as $16.0 million even though no wrongdoing allegations are specifically attributable to Avista Energy. Avista Energy believes its settlement insulates it from any such liability and that as a dismissed party it cannot be drawn back into the litigation. Avista Energy intends to vigorously dispute APX’s assertions of indirect liability, but cannot at this time predict the eventual outcome.

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. In August 2007, the Ninth Circuit found that the FERC 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 (Order) and on April 5, 2013 expanded 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 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 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.

On July 11, 2012 and March 28, 2013, Avista Energy and Avista Corp. 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 the California Department of Water Resources). The FERC approved the settlements and they are final. The remaining direct claimant against Avista Corp. and Avista Energy in this proceeding is the City of Seattle, Washington (Seattle).

With regard to the Seattle claims, on March 28, 2014, the Presiding ALJ issued an Initial Decision finding that: 1) Seattle failed to demonstrate that either Avista Corp. 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 Corp. 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 Corp. or Avista Energy engaged in any specific violations of substantive provisions of the FPA 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 FPA. On May 22, 2015, the FERC issued its Order on Initial Decision in which it upheld the ALJ’s Initial Decision denying all of Seattle’s claims against Avista Corp. and Avista Energy. Seattle filed a Request for Rehearing of the FERC’s Order on Initial Decision which was denied on December 31, 2015. Seattle appealed the FERC’s decision to the Ninth Circuit. 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 Litigation

In 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 Talen (formerly PPL Montana), Puget Sound Energy, Portland General Electric Company, NorthWestern Energy and PacifiCorp. The Complaint alleged certain violations of the Clean Air Act, including the New Source Review, Title V and opacity requirements.

The Complaint alleged certain violations of the Clean Air Act and the New Source Review with respect to post-January 1, 2001 Colstrip projects. The Plaintiffs requested 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 liability trial was scheduled to start on May 31, 2016. The parties engaged in settlement discussions with the Plaintiffs to resolve the claims raised in the litigation. On July 12, 2016, the parties filed a proposed consent decree with the court which contained the terms of the settlement of the matter with respect to all four units at Colstrip. The settlement does not include any monetary payments by any party, dismisses all claims against all four units, and provides for the shut-down of units 1 and 2 (which are owned solely by Talen Montana and Puget Sound Energy) no later than July, 2022. The Environmental Protection Agency (EPA) and the Department of Justice have 45 days to comment on the proposed Consent Decree or intervene as a matter of right. Following the 45-day period the parties will seek approval and entry of the Consent Decree or will take other appropriate actions should there be any material comments or if the United States intervenes. The Consent Decree permits the parties to petition the Court for costs and attorneys’ fees within 30 days after the Court enters the Consent Decree.

The Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels (referred to as "Total Dissolved Gas" or "TDG") in the Clark Fork River exceed state of Idaho and federal water quality numeric standards downstream of 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. Under the terms of a gas supersaturation mitigation plan, Avista is reducing TDG by constructing spill crest modifications on spill gates at the dam, and the Company expects to continue spill crest modifications over the next several years, in ongoing consultation with key stakeholders. Avista Corp. cannot at this time predict the outcome or estimate a range of costs associated with this contingency; however, 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. In 2010, the USFWS issued a revised designation of critical habitat for bull trout, which includes the lower Clark Fork River. The USFWS issued a final recovery plan in October 2015.

The Clark Fork Settlement Agreement (CFSA) 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. Parties to the CFSA are working to resolve several technical issues, including screening for fish pathogens prior to transport and several other issues of concern between the states of Montana and Idaho as well as to the USFWS and Avista. Fishway designs for Cabinet Gorge have been completed, and the Company is currently developing construction cost estimates. The Company believes its ongoing efforts through the Clark Fork Settlement Agreement continue to effectively address issues related to bull trout. Avista Corp. cannot at this time predict the outcome or estimate a range of costs associated with this contingency; however, 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.

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.

NOTE 12. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. 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. AEL&P is a separate reportable business segment as it has separate financial reports that are reviewed in detail by the Chief Operating Decision Maker and its operations and risks are sufficiently different from Avista Utilities and the other businesses at AERC that it cannot be aggregated with any other operating segments. The Other category, which is not a reportable segment, includes other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital.

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

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the three months ended June 30, 2016:						
Operating revenues	$ 302,641	$ 10,247	$ 312,888	$ 5,950	$ —	$ 318,838
Resource costs	106,607	3,208	109,815	—	—	109,815
Other operating expenses	75,790	2,876	78,666	6,281	—	84,947
Depreciation and amortization	38,351	1,327	39,678	192	—	39,870
Income (loss) from operations	59,862	2,252	62,114	(523)	—	61,591
Interest expense (2)	20,462	895	21,357	149	(34)	21,472
Income taxes (4)	16,349	676	17,025	(315)	—	16,710
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	26,771	1,058	27,829	(575)	—	27,254
Capital expenditures (3)	88,048	5,889	93,937	46	—	93,983
For the three months ended June 30, 2015:						
Operating revenues	$ 320,698	$ 10,232	$ 330,930	$ 6,502	$ (100)	$ 337,332
Resource costs	137,896	3,220	141,116	—	—	141,116
Other operating expenses	70,348	2,764	73,112	6,746	(100)	79,758
Depreciation and amortization	34,351	1,325	35,676	165	—	35,841
Income (loss) from operations	55,415	2,354	57,769	(409)	—	57,360
Interest expense (2)	18,969	895	19,864	147	(30)	19,981
Income taxes	14,632	591	15,223	(207)	—	15,016
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	24,478	925	25,403	(353)	—	25,050
Capital expenditures (3)	90,800	5,355	96,155	92	—	96,247
For the six months ended June 30, 2016:						
Operating revenues	$ 702,788	$ 22,893	$ 725,681	$ 11,330	$ —	$ 737,011
Resource costs	265,685	5,849	271,534	—	—	271,534
Other operating expenses	149,046	5,399	154,445	12,106	—	166,551
Depreciation and amortization	76,217	2,653	78,870	380	—	79,250
Income (loss) from operations	161,107	7,725	168,832	(1,156)	—	167,676
Interest expense (2)	40,880	1,790	42,670	310	(97)	42,883
Income taxes (4)	45,021	2,571	47,592	(537)	—	47,055
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	81,758	4,019	85,777	(874)	—	84,903
Capital expenditures (3)	172,483	10,332	182,815	165	—	182,980

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the six months ended June 30, 2015:						
Operating revenues	$ 744,781	$ 23,006	$ 767,787	$ 16,585	$ (550)	$ 783,822
Resource costs	344,556	6,120	350,676	—	—	350,676
Other operating expenses	140,757	5,527	146,284	17,012	(550)	162,746
Depreciation and amortization	67,348	2,628	69,976	334	—	70,310
Income (loss) from operations	140,203	7,493	147,696	(761)	—	146,935
Interest expense (2)	37,937	1,799	39,736	311	(52)	39,995
Income taxes	39,520	2,275	41,795	(532)	—	41,263
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	68,862	3,559	72,421	(922)	—	71,499
Capital expenditures (3)	172,012	5,740	177,752	504	—	178,256
Total Assets:						
As of June 30, 2016:	$ 4,742,362	$ 272,344	$ 5,014,706	$ 54,315	$ —	$ 5,069,021
As of December 31, 2015:	$ 4,601,708	$ 265,735	$ 4,867,443	$ 39,206	$ —	$ 4,906,649

(1) Intersegment eliminations reported as operating revenues and resource costs represent intercompany purchases and sales of electric capacity and energy. Intersegment eliminations reported as interest expense 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 Condensed Consolidated Statements of Cash Flows.

(4) Income tax expense for the six months ended June 30, 2016 includes excess tax benefits of $1.6 million related to the adoption of ASU 2016-09 during the second quarter of 2016. The excess tax benefits are not included in the second quarter 2016 results as they were applied retroactively to January 1, 2016. See Note 2 of the Notes to Condensed Consolidated Financial Statements for further discussion.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have reviewed the accompanying condensed consolidated balance sheet of Avista Corporation and subsidiaries (the “Company”) as of June 30, 2016, and the related condensed consolidated statements of income and comprehensive income for the three-month and six-month periods ended June 30, 2016 and 2015 and the related condensed consolidated statements of equity and cash flows for the six-month periods ended June 30, 2016 and 2015. These interim financial statements are the responsibility of the Company’s management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our reviews, we are not aware of any material modifications that should be made to such condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Avista Corporation and subsidiaries as of December 31, 2015, and the related consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for the year then ended (not presented herein); and in our report dated February 23, 2016, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2015 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP

Seattle, Washington
August 2, 2016

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

Management’s Discussion and Analysis of Financial Condition and Results of Operations has been prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. The interim Management’s Discussion and Analysis of Financial Condition and Results of Operations does not contain the full detail or analysis which would be included in a full fiscal year Form 10-K; therefore, it should be read in conjunction with the Company's 2015 Form 10-K.

Business Segments

Our business segments have not changed during the six months ended June 30, 2016. See the 2015 Form 10-K as well as “Note 12 of the Notes to Condensed Consolidated Financial Statements” for further information regarding 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 three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Avista Utilities	$ 26,771	$ 24,478	$ 81,758	$ 68,862
AEL&P	1,058	925	4,019	3,559
Ecova - Discontinued operations	—	196	—	196
Other	(575)	(353)	(874)	(922)
Net income attributable to Avista Corporation shareholders	$ 27,254	$ 25,246	$ 84,903	$ 71,695

Executive Level Summary

Overall Results

Net income attributable to Avista Corp. shareholders was $27.3 million for the three months ended June 30, 2016, an increase from $25.2 million for the three months ended June 30, 2015. Avista Utilities' earnings increased primarily due to an increase in gross margin (operating revenues less resource costs) as a result of general rate increases (net of an electric general rate decrease in Washington) and the implementation of decoupling mechanisms in Idaho and Oregon. The increases to gross margin were partially offset by weather that was warmer than the prior year in April and May (which reduced both electric and natural gas heating loads) and cooler than the prior year during June (which reduced electric cooling loads). Also, we had increases in other operating expenses and depreciation and amortization, all of which were expected. There was also a slight increase in earnings at AEL&P offset by a slight increase in the net loss at the other businesses.

Net income attributable to Avista Corp. shareholders was $84.9 million for the six months ended June 30, 2016, an increase from $71.7 million for the six months ended June 30, 2015. Avista Utilities' earnings increased primarily due to an increase in gross margin as a result of general rate increases (net of an electric general rate decrease in Washington), colder weather in the first quarter of 2016 as compared to the first quarter of 2015 (which increased retail electric and natural gas volumes) and the implementation of decoupling mechanisms in Idaho and Oregon. The increases to gross margin were partially offset by weather which was warmer than the prior year in April and May (which reduced electric and natural gas heating loads) and cooler than the prior year during June (which reduced electric cooling loads). Also, there were increases in other operating expenses and depreciation and amortization, all of which were expected. There was also a slight increase in earnings at AEL&P and a slight decrease in the net loss at the other businesses.

More detailed explanations of the fluctuations are provided in the results of operations and business segment discussions (Avista Utilities, AEL&P, and the other businesses) that follow this section.

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

2015 General Rate Cases

In January 2016, we received an order (Order 05) that concluded our electric and natural gas general rate cases that were originally filed with the UTC in February 2015. New electric and natural gas rates were effective on January 11, 2016.

The UTC-approved rates are designed to provide a 1.6 percent, or $8.1 million decrease in electric base revenue, and a 7.4 percent, or $10.8 million increase in natural gas base revenue. The UTC also approved a rate of return (ROR) on rate base of 7.29 percent, with a common equity ratio of 48.5 percent and a 9.5 percent return on equity (ROE).

UTC Order denying Industrial Customers of Northwest Utilities / Public Counsel Joint Motion for Clarification, UTC Staff Motion to Reconsider and UTC Staff Motion to Reopen Record

On January 19, 2016, the Industrial Customers of Northwest Utilities (ICNU) and the Public Counsel Unit of the Washington State Office of the Attorney General (PC) filed a Joint Motion for Clarification with the UTC. In its Motion for Clarification, ICNU and PC requested that the UTC clarify the calculation of the electric attrition adjustment and the end-result revenue decrease of $8.1 million. ICNU and PC provided their own calculations in their Motion, and suggested that the revenue decrease should have been $19.8 million based on their reading of the UTC’s Order.

On January 19, 2016, the UTC Staff, which is a separate party in the general rate case proceedings from the UTC Advisory Staff, filed a Motion to Reconsider with the UTC. In its Motion to Reconsider, the Staff provided calculations and explanations that suggested that the electric revenue decrease should have been a revenue decrease of $27.4 million instead of $8.1 million, based on its reading of the UTC's Order. Further, on February 4, 2016, the UTC Staff filed a Motion to Reopen Record for the Limited Purpose of Receiving into Evidence Instruction on Use and Application of Staff’s Attrition Model, and sought to supplement the record “to incorporate all aspects of the Company’ Power Cost Update.” Within this Motion, UTC Staff updated its suggested electric revenue decrease to $19.6 million.

None of the parties in their Motions raised issues with the UTC’s decision on the natural gas revenue increase of $10.8 million.

On February 19, 2016, the UTC issued an order (Order 06) denying the Motions summarized above and affirmed Order 05 including an $8.1 million decrease in electric base revenue.

PC Petition for Judicial Review

On March 18, 2016, PC filed in Thurston County Superior Court a Petition for Judicial Review of the UTC's Order 05 and Order 06 described above that concluded our electric and natural gas general rate cases. In its Petition for Judicial Review, PC seeks judicial review of five aspects of Order 05 and Order 06, alleging, among other things, that (1) the UTC exceeded its statutory authority by setting rates for our natural gas and electric services based on amounts for utility plant and facilities that are not "used and useful" in providing utility service to customers; (2) the UTC acted arbitrarily and capriciously in granting an attrition adjustment for our electric operations after finding that the we did not meet the newly articulated standard regarding attrition adjustments; (3) the UTC erred in applying the "end results test" to set rates for our electric operations that are not supported by the record; (4) the UTC did not correct its calculation of our electric rates after significant errors were brought to its attention; and (5) the UTC's calculation of our electric rates lacks substantial evidence.

PC is requesting that the Court (1) vacate or set aside portions of the UTC’s orders; (2) identify the errors contained in the UTC’s orders; (3) find that the rates approved in Order 05 and reaffirmed in Order 06 are unlawful and not fair, just and reasonable; (4) remand the matter to the UTC for further proceedings consistent with these rulings, including a determination of our revenue requirement for electric and natural gas services; and (5) find the customers are entitled to a refund.

On April 18, 2016, PC filed an application with the Thurston County Superior Court to certify this matter for review directly by the Court of Appeals, an intermediate appellate court in the State of Washington. After briefing and argument, the matter was certified on April 29, 2016 and accepted by the Court of Appeals on July 29, 2016.

The new rates established by Order 05 will continue in effect while the Petition for Judicial Review is being considered. We believe the UTC's Order 05 and Order 06 finalizing the electric and natural gas general rate cases provide a reasonable end result for all parties. If the outcome of the judicial review were to result in an electric rate reduction greater than the decrease ordered by the UTC, it may not provide us with a reasonable opportunity to earn the rate of return authorized by the UTC.

2016 General Rate Cases

On February 19, 2016, we filed electric and natural gas general rates cases with the UTC. Our proposal includes an 18-month rate plan, with new rates taking effect on January 1, 2017 and January 1, 2018. Under this plan, we would not file a future rate case for new rates to be effective prior to July 1, 2018. Capital investments in infrastructure, technology and system maintenance are the main drivers in our electric and natural gas rate requests.

The 2017 increase, if approved, would increase overall base electric rates 7.8 percent (designed to increase annual electric revenues by $38.6 million) and overall base natural gas rates 5.0 percent (designed to increase annual natural gas revenues by $4.4 million).

In addition, we have requested a second step increase effective January 1, 2018, which would increase overall base electric rates by 3.9 percent (designed to increase electric revenues by $10.3 million for the January through June 2018 period) and overall base natural gas rates by 1.8 percent (designed to increase natural gas revenues by $0.9 million for the January through June 2018 period). We have proposed to offset the electric increase, for the period January through June 2018, with available ERM deferrals. As a result, customers would not see an electric general rate case bill increase in 2018 prior to July 1, 2018.

Our requests are based on a proposed ROR on rate base of 7.64 percent with a common equity ratio of 48.5 percent and a 9.9 percent ROE.

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

Idaho General Rate Cases

2015 General Rate Cases

In December 2015, the IPUC approved a settlement agreement between Avista Utilities and all interested parties related to our electric and natural gas general rate cases, which were originally filed with the IPUC on June 1, 2015. New rates were effective on January 1, 2016.

The settlement agreement is designed to increase annual electric base revenues by $1.7 million or 0.7 percent and annual natural gas base revenues by $2.5 million or 3.5 percent. The settlement is based on a ROR of 7.42 percent with a common equity ratio of 50 percent and a 9.5 percent ROE.

The settlement agreement also reflects the following:

- the discontinuation of the after-the-fact earnings test (provision for earnings sharing) that was originally agreed to as part of the settlement of our 2012 electric and natural gas general rate cases, and
- the implementation of electric and natural gas Fixed Cost Adjustment mechanisms, as discussed below.

2016 General Rate Case

On May 26, 2016, we filed an electric general rate case with the IPUC. We did not request a change in natural gas rates. Capital investments in infrastructure and system maintenance are the main drivers in our electric rate request.

We have requested an overall increase in billed electric rates of 6.3 percent (designed to increase annual electric revenues by $15.4 million), effective January 1, 2017.

Our request is based on a proposed rate of return on rate base of 7.78 percent with a common equity ratio of 50 percent and a 9.9 percent return on equity.

The IPUC has up to nine months to review the filings and issue a decision.

Oregon General Rate Cases

2015 General Rate Case

On February 29, 2016, the OPUC issued a preliminary order (and a final order on March 15, 2016) concluding our natural gas general rate case, which was originally filed with OPUC in May 2015. The OPUC order approved rates designed to increase overall billed natural gas rates by 4.9 percent (designed to increase annual natural gas revenues by $4.5 million). New rates went into effect on March 1, 2016. The final OPUC order incorporated two partial settlement agreements which were entered into during November 2015 and January 2016.

The OPUC order provides for an overall authorized ROR of 7.46 percent with a common equity ratio of 50 percent and a 9.4 percent ROE.

The November 2015 partial settlement agreement, approved by the OPUC, included a provision for the implementation of a decoupling mechanism, similar to the Washington and Idaho mechanisms described below. See further description and a summary of the balances recorded under this mechanism below.

During the general rate case process, the OPUC staff filed testimony that included a recommendation to disallow $1.2 million (Oregon's share) of Project Compass costs primarily related to the delay in the full completion of the project. The OPUC approved the full recovery of Oregon’s portion of Project Compass costs, as well as all other capital investment included in our case.

2016 General Rate Cases

We expect to file a natural gas general rate case with the OPUC in the second half of 2016.

Alaska General Rate Case

AEL&P's last general rate case was filed in 2010 and the final order approving retail rates was issued by the Regulatory Commission of Alaska (RCA) in 2011. We expect to file an electric general rate case with the RCA during the second half of 2016, based largely on the addition to rate base of a new backup generation plant.

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to Avista Utilities' customers with no change in gross margin 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 $27.7 million as of June 30, 2016 and a liability of $17.9 million as of December 31, 2015. These balances represent amounts due to customers.

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 and defer these differences (to the extent of the excess, if any, over a $4.0 million deadband) for future surcharge or rebate to customers. Total net deferred power costs under the ERM were a liability of $18.4 million as of June 30, 2016, compared to a liability of $18.0 million as of December 31, 2015. These deferred power cost balances represent amounts due to customers.

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 for future surcharge or rebate to customers. The October 1 rate adjustments recover or rebate power supply costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a liability of $0.8 million as of June 30, 2016 compared to an asset of $0.2 million as of December 31, 2015.

Decoupling and Earnings Sharing Mechanisms

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, which could be caused by changes in weather, energy conservation or the economy. Under decoupling, our electric and natural gas revenues will be adjusted each month to be based on the number of customers in certain customer rate classes, 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. Only the residential and commercial customer classes are included in our decoupling mechanisms described below.

Washington Decoupling and Earnings Sharing Mechanisms

In Washington, the UTC approved our decoupling mechanisms for electric and natural gas for a five-year period that commenced January 1, 2015. 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 are made to accrue for any earnings which occurred during that year that were above the established threshold. These earnings tests will reflect actual decoupled revenues, normalized power supply costs and other normalizing adjustments. The operation of the Washington decoupling and earnings sharing mechanisms have not changed for the six months ended June 30, 2016. These decoupling and earnings sharing mechanisms are more fully described in the 2015 Form 10-K.

Idaho Fixed Cost Adjustment (FCA) and Earnings Sharing Mechanisms

In Idaho, the IPUC approved the implementation of FCAs for electric and natural gas (similar in operation and effect to the Washington decoupling mechanisms) for an initial term of three years, commencing on January 1, 2016.

For the period 2013 through 2015, we had an after-the-fact earnings test, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earned more than a 9.8 percent ROE, we were required to share with customers 50 percent of any earnings above the 9.8 percent. This after-the-fact earnings test was discontinued as part of the settlement of our 2015 Idaho electric and natural gas general rates cases (discussed in further detail above).

Oregon Decoupling Mechanism

In February 2016, the OPUC approved the implementation of a decoupling mechanism for natural gas, similar to the Washington and Idaho mechanisms described above. The decoupling mechanism became effective on March 1, 2016 and there will be an opportunity for interested parties to review the mechanism and recommend changes, if any, by September 2019. The OPUC rules require that an earnings review be conducted on an annual basis, which is filed by us with the OPUC on or before June 1st of each year for the prior calendar year. In the annual earnings review, if we earn more than 100 basis points above our allowed return on equity, one-third of the earnings above the 100 basis points would be deferred and later returned to customers.

Cumulative Decoupling and Earnings Sharing Mechanism Balances

As of June 30, 2016 and December 31, 2015, we had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in our various jurisdictions (dollars in thousands):

	June 30, 2016	December 31, 2015
Washington		
Decoupling surcharge	$ 26,662	$ 10,933
Provision for earnings sharing rebate	(1,790)	(3,422)
Idaho		
Decoupling surcharge	$ 7,177	n/a
Provision for earnings sharing rebate	(6,578)	(8,814)
Oregon		
Decoupling surcharge	$ 1,881	n/a
Provision for earnings sharing rebate	—	—

(n/a) This mechanism did not exist during this time period.

See "Results of Operations - Avista Utilities" for further discussion of the amounts recorded to operating revenues in 2015 and 2016 related to the decoupling and earnings sharing mechanisms.

Results of Operations - Overall

The following provides an overview of changes in our Condensed Consolidated Statements of Income. More detailed explanations are provided in the business segment discussions (Avista Utilities, AEL&P, and the other businesses) that follow this section.

The balances included below for utility operations reconcile to the Condensed Consolidated Statements of Income.

Three months ended June 30, 2016 compared to the three months ended June 30, 2015

Utility revenues decreased $17.9 million, after elimination of intracompany revenues (within Avista Utilities) of $13.1 million for the second quarter of 2016 and $26.6 million for the second quarter of 2015. The entire decrease in utility revenues was attributable to Avista Utilities as AEL&P's revenues were flat compared to the prior year. Including intracompany revenues, Avista Utilities' electric revenues decreased $1.4 million and natural gas revenues decreased $30.0 million.

Utility resource costs decreased $31.3 million, after elimination of intracompany resource costs of $13.1 million for the second quarter of 2016 and $26.6 million for second quarter of 2015. The entire decrease in resource costs was attributable to Avista Utilities as AEL&P's electric resource costs were flat compared to the prior year. Including intracompany resource costs, Avista Utilities' electric resource costs decreased $11.0 million and natural gas resource costs decreased $33.7 million.

Utility other operating expenses increased $5.6 million, all attributable to Avista Utilities. Avista Utilities' other operating expenses increased due to an increase in medical costs, electric generation operating and maintenance expenses, natural gas distribution expenses and pension and other postretirement benefit expenses.

Utility depreciation and amortization increased $4.0 million, driven by additions to utility plant.

Income taxes increased $1.7 million and our effective tax rate was 38.0 percent for the second quarter of 2016 compared to 37.5 percent for the second quarter of 2015. The increase in tax expense is consistent with an increase in income before income taxes.

Six months ended June 30, 2016 compared to the six months ended June 30, 2015

Utility revenues decreased $41.6 million, after elimination of intracompany revenues of $31.2 million for the six months ended June 30, 2016 and $44.4 million for the six months ended June 30, 2015. Avista Utilities' portion of utility revenues decreased $41.5 million for the six months ended June 30, 2016 and AEL&P electric revenues decreased $0.1 million. Including intracompany revenues, Avista Utilities' electric revenues decreased $5.5 million and natural gas revenues decreased $49.6 million.

Non-utility revenues decreased $5.3 million due to the long-term fixed rate electric capacity contract that was previously held by Spokane Energy being transferred to Avista Corp. during the second quarter of 2015. The capacity revenue from this contract was included in non-utility revenues when it was held by Spokane Energy in 2015.

Utility resource costs decreased $79.1 million, after elimination of intracompany resource costs of $31.2 million for the six months ended June 30, 2016 and $44.4 million for the six months ended June 30, 2015. Avista Utilities' portion of resource costs decreased $78.8 million and AEL&P electric resource costs decreased $0.3 million. Including intracompany resource costs, Avista Utilities' electric resource costs decreased $27.5 million and natural gas resource costs decreased $64.5 million.

Utility other operating expenses increased $8.2 million. Avista Utilities' portion of other operating expenses increased $8.3 million due to an increase in medical costs, electric generation operating and maintenance expenses, natural gas distribution expenses and pension and other postretirement benefit expenses.

Utility depreciation and amortization increased $8.9 million, driven by additions to utility plant.

Other non-utility operating expenses decreased $4.4 million due to the long-term fixed rate electric capacity contract that was previously held by Spokane Energy being transferred to Avista Corp. during the second quarter of 2015. The amortization of this contract was included in non-utility operating expenses when it was held by Spokane Energy in 2015.

Income taxes increased $5.8 million and our effective tax rate was 35.6 percent for the first six months of 2016 compared to 36.6 percent for the first six months of 2015. The increase in income tax expense was primarily due to an increase in income before income taxes, partially offset by excess tax benefits of $1.6 million during 2016 for the settlement of share-based payment awards. See Note 2 of the Notes to Condensed Consolidated Financial Statements for further discussion of the excess tax benefits. The decrease in the effective tax rate was primarily related to the excess tax benefits recognized in 2016.

Results of Operations - Avista Utilities

Non-GAAP Financial Measures

The following discussion for Avista Utilities includes two financial measures that are considered “non-GAAP financial measures,” electric gross margin and natural gas gross margin. In the AEL&P section, we include a discussion of electric gross margin. Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included (excluded) in the most directly comparable measure calculated and presented in accordance with GAAP. The presentation of electric gross margin and natural gas gross margin for Avista Utilities 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. In addition, we present electric and natural gas gross margin separately below as each business has slightly different cost sources, cost recovery mechanisms and jurisdictions, where separate analysis is beneficial. 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.

Three months ended June 30, 2016 compared to the three months ended June 30, 2015

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

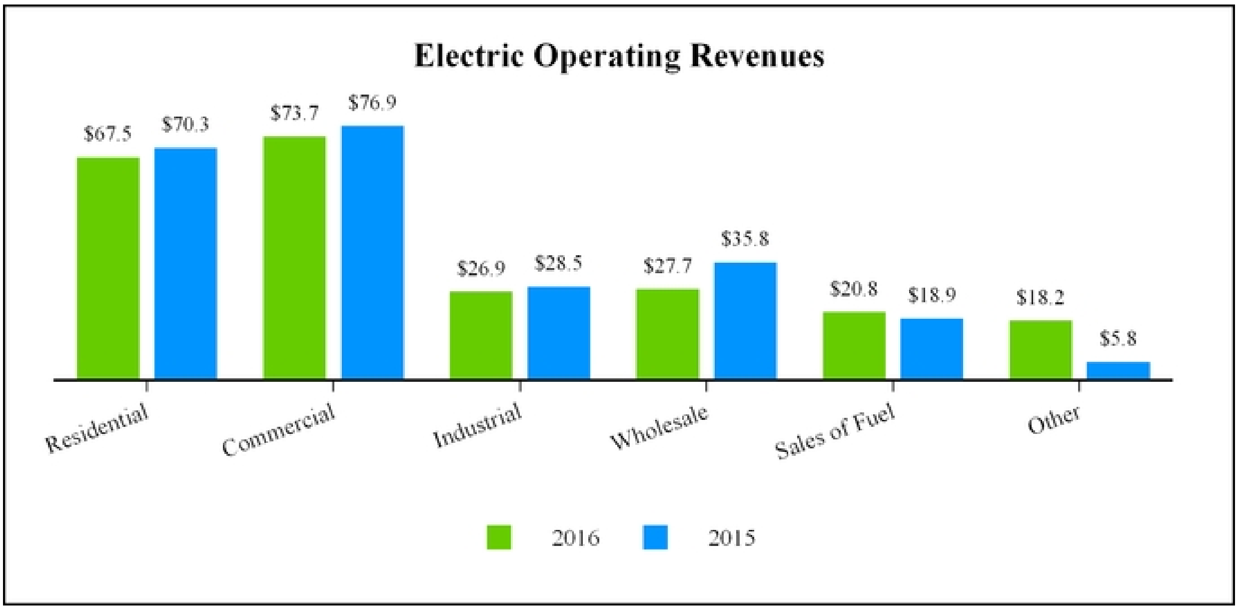
	Electric		Natural Gas		Intracompany		Total	
	2016	2015	2016	2015	2016	2015	2016	2015
Operating revenues	$ 234,791	$ 236,254	$ 80,955	$ 111,002	$ (13,105)	$ (26,558)	$ 302,641	$ 320,698
Resource costs	73,350	84,326	46,362	80,128	(13,105)	(26,558)	106,607	137,896
Gross margin	$ 161,441	$ 151,928	$ 34,593	$ 30,874	$ —	$ —	$ 196,034	$ 182,802

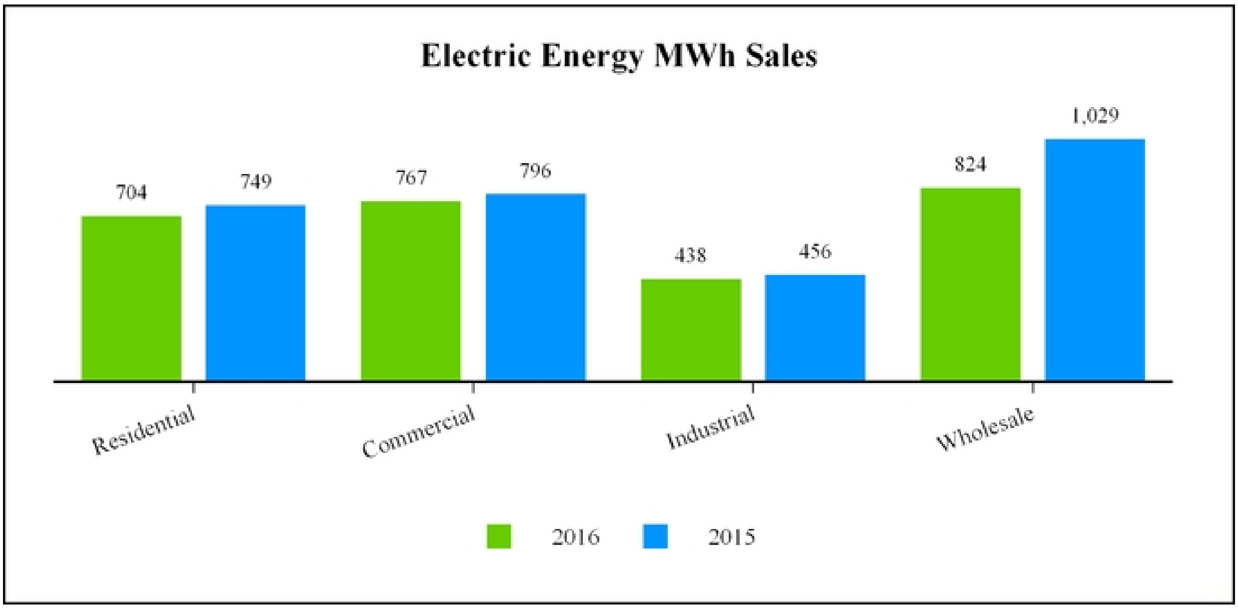
The gross margin on electric sales increased $9.5 million and the gross margin on natural gas sales increased $3.7 million in the second quarter of 2016 compared to the second quarter of 2015. The increase in electric gross margin was primarily due to a general rate increase in Idaho, lower resource costs and the implementation of decoupling in Idaho, partially offset by a general rate decrease in Washington and lower retail loads. Weather was warmer than the prior year in April and May (which reduced heating loads) and cooler than the prior year in June (which reduced cooling loads) but significantly warmer than normal. As such, retail electric loads decreased as compared to prior year and the impact as compared to normal was mostly offset by decoupling mechanisms. See the table below for a comparison of the amounts recorded for decoupling by jurisdiction. For the second quarter of 2016, we had a $0.2 million pre-tax expense under the ERM in Washington. We did not have any pre-tax benefit or expense under the ERM for the second quarter of 2015.

The increase in natural gas gross margin was primarily due to general rate cases in each of our jurisdictions, lower natural gas resource costs and the implementation of decoupling mechanisms in Idaho and Oregon, partially offset by lower retail loads. Weather was warmer than the prior year in April and May (which reduced heating loads) but significantly warmer than normal. As such, retail natural gas loads decreased as compared to prior year and the impact as compared to normal was mostly offset by decoupling mechanisms. See the table below for a comparison of the amounts recorded for decoupling by jurisdiction.

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 condensed consolidated financial statements but are included in the separate results for electric and natural gas presented below.

The following graphs present our utility electric operating revenues and megawatt-hour (MWh) sales for the three months ended June 30 (dollars in millions and MWhs in thousands):





The following table presents Avista Utilities' decoupling and customer earnings sharing mechanisms by jurisdiction that are included in utility electric operating revenues for the three months ended June 30 (dollars in thousands):

	Electric Operating Revenues	
	2016	2015
Washington		
Decoupling surcharge (rebate)	$ 4,553	$ (2,036)
Provision for earnings sharing (1)	1,119	(560)
Idaho		
Decoupling surcharge	$ 2,651	n/a
Provision for earnings sharing (2)	711	—

(1) The provision for earnings sharing in Washington in the second quarter of 2016 resulted from a $1.2 million reduction in the 2015 provision for earnings sharing (which increased 2016 revenues), partially offset by a $0.1 million provision for the second quarter of 2016.

(2) The provision for earnings sharing in Idaho in the second quarter of 2016 resulted from a reduction in the 2015 provision for earnings sharing (which increased 2016 revenues). Beginning in 2016 there is no longer an earnings sharing mechanism in Idaho.

(n/a) This mechanism did not exist during this time period.

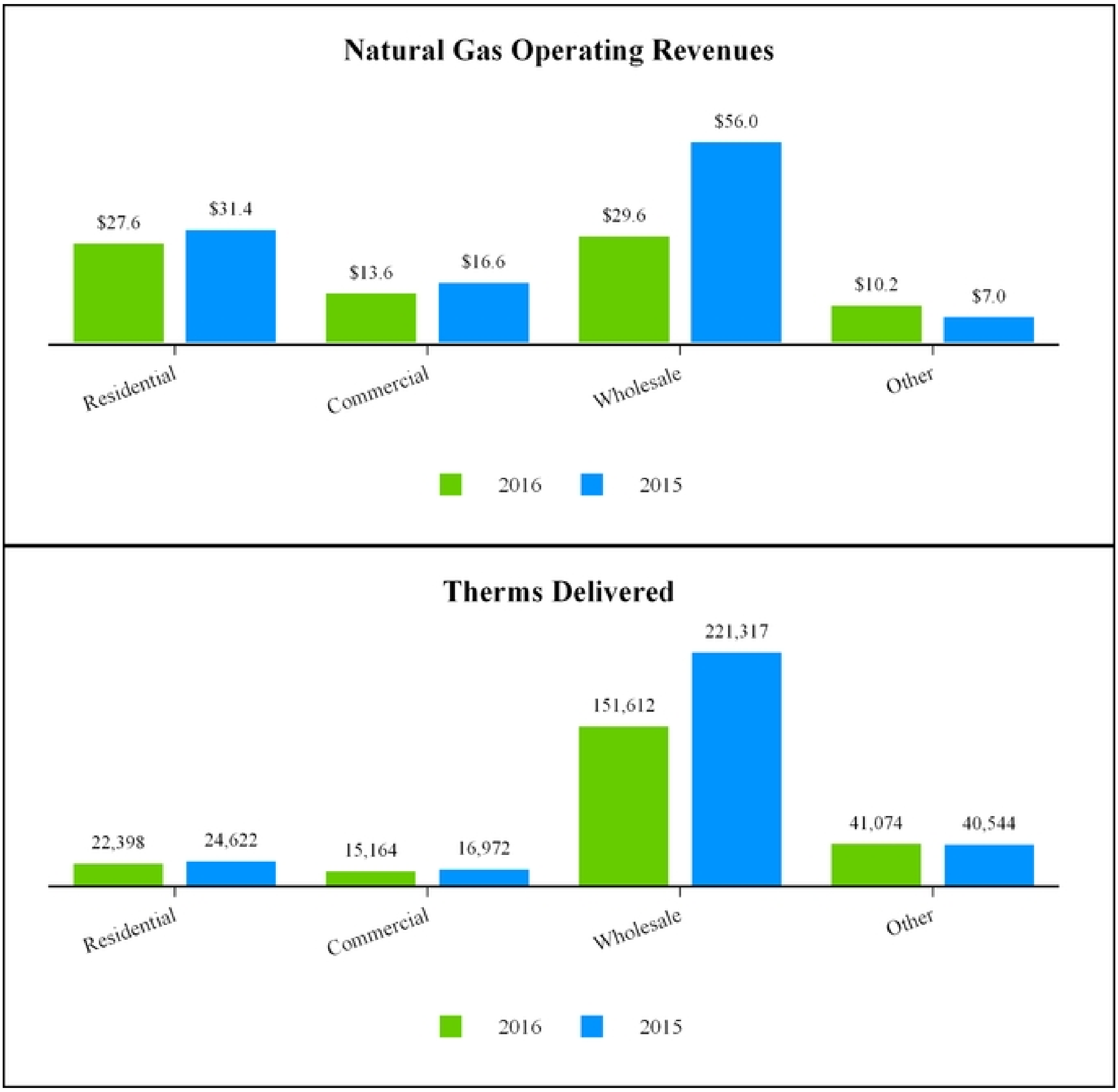
Total electric revenues decreased $1.4 million for the second quarter of 2016 as compared to the second quarter of 2015 due to the following:

- a $7.5 million decrease in retail electric revenue due to a decrease in total MWhs sold (decreased revenues $8.2 million), partially offset by an increase in revenue per MWh (increased revenues $0.7 million).
  - The increase in revenue per MWh was primarily due to a general rate increase in Idaho and the expiration of the ERM rebate in Washington, partially offset by a general rate decrease in Washington.
  - The decrease in total retail MWhs sold was the result of weather that was warmer than the prior year in April and May (which reduced heating loads) and cooler than the prior year in June (which reduced cooling loads), partially offset by customer growth. Compared to the second quarter of 2015, residential electric use per customer decreased 7 percent and commercial use per customer decreased 5 percent.
- an $8.1 million decrease in wholesale electric revenues due to a decrease in sales volumes (decreased revenues $6.8 million) and a decrease in sales prices (decreased revenues $1.3 million). The fluctuation in volumes and prices was

primarily the result of our optimization activities during the quarter.

- a $1.9 million increase in sales of fuel due to an increase in sales of natural gas fuel as part of thermal generation resource optimization activities. For the second quarter of 2016, $8.0 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For the second quarter of 2015, $13.0 million of these sales were made to our natural gas operations.
- a $2.4 million decrease in the electric provision for earnings sharing (which increases revenues) primarily due to a $1.2 million reduction in the 2015 provision for earnings sharing in Washington and a $0.7 million reduction in the 2015 provision for earnings sharing in Idaho recorded in the second quarter of 2016.
- a $9.2 million increase in electric revenue due to decoupling, which reflected the implementation of a decoupling mechanism in Idaho effective January 1, 2016 and lower retail revenues (as a result of warmer weather in April and May and cooler weather in June) in the second quarter of 2016.

The following graphs present our utility natural gas operating revenues and therms delivered for the three months ended June 30 (dollars in millions and therms in thousands):



The following table presents Avista Utilities' decoupling and customer earnings sharing mechanisms by jurisdiction that are included in utility natural gas operating revenues for the three months ended June 30 (dollars in thousands):

	Natural Gas Operating Revenues	
	2016	2015
Washington		
Decoupling surcharge	$ 3,595	$ 2,231
Provision for earnings sharing	(320)	—
Idaho		
Decoupling surcharge	$ 589	n/a
Provision for earnings sharing	n/a	—
Oregon		
Decoupling surcharge	$ 1,690	n/a
Provision for earnings sharing	—	—

(n/a) This mechanism did not exist during this time period.

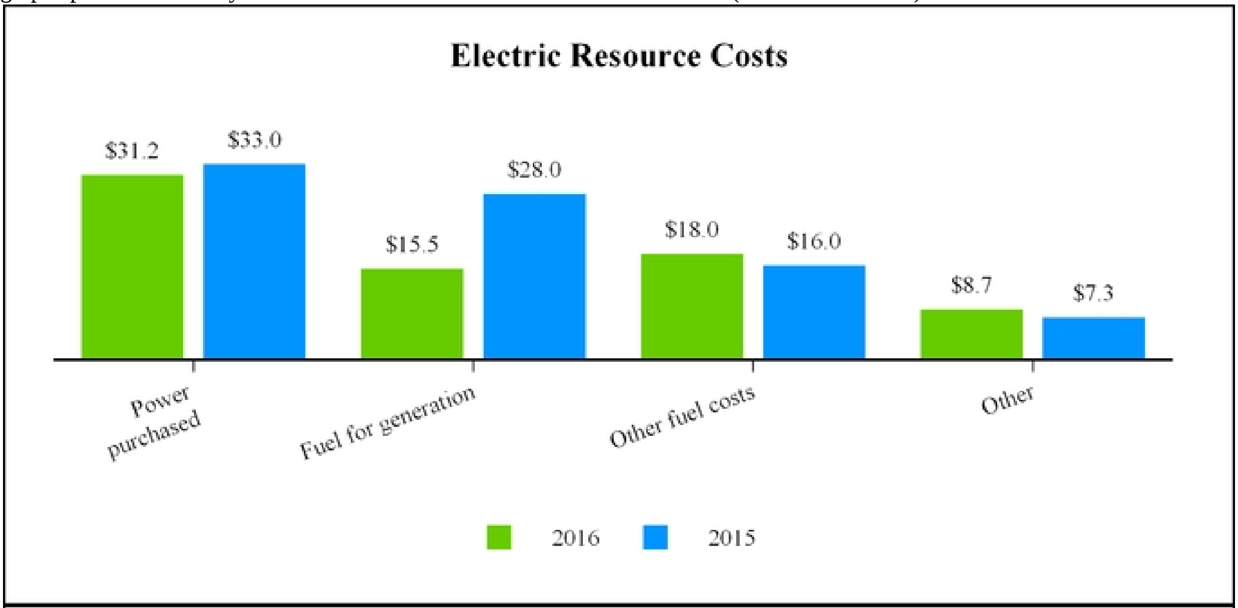
Total natural gas revenues decreased $30.0 million for the second quarter of 2016 as compared to the second quarter of 2015 due to the following:

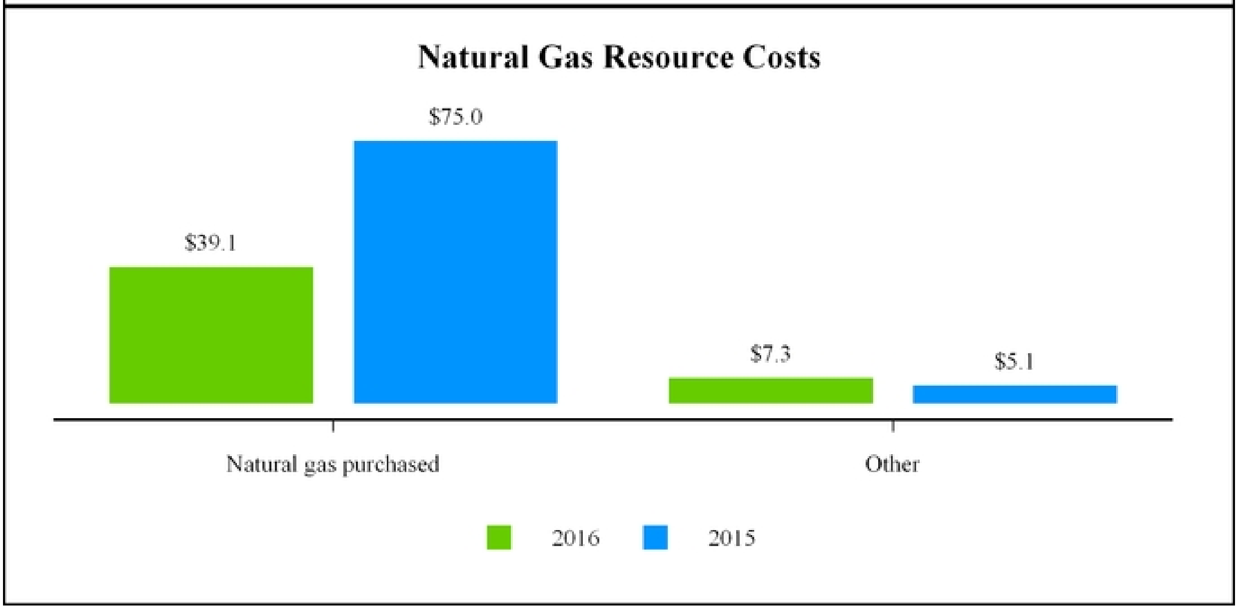
- a $7.1 million decrease in natural gas retail revenues due to lower retail rates (decreased revenues $2.8 million), and a decrease in volumes (decreased revenues $4.3 million).
  - Lower retail rates were due to PGAs, partially offset by general rate cases.
  - We sold less retail natural gas in the second quarter of 2016 as compared to the second quarter of 2015 due to weather that was warmer than the prior year in April and May. Compared to the second quarter of 2015, residential natural gas use per customer decreased 12 percent and commercial use per customer decreased 14 percent. Heating degree days in Spokane were 37 percent below normal and 12 percent below the second quarter of 2015. Heating degree days in Medford were 35 percent below normal and 23 percent below the second quarter of 2015.
- a $26.4 million decrease in wholesale natural gas revenues due to a decrease in prices (decreased revenues $12.9 million) and a decrease in volumes (decreased revenues $13.5 million). In the second quarter of 2016, $5.1 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In the second quarter of 2015, $13.5 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.
- a $3.5 million increase for natural gas decoupling revenues due primarily to the implementation of decoupling mechanisms in Idaho and Oregon, as well as the impact of weather that was warmer than the prior year in the second quarter of 2016.

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

	Electric Customers		Natural Gas Customers	
	2016	2015	2016	2015
Residential	329,551	325,710	299,860	295,398
Commercial	41,732	41,203	34,867	34,178
Interruptible	—	—	37	35
Industrial	1,346	1,371	255	263
Public street and highway lighting	559	525	—	—
Total retail customers	373,188	368,809	335,019	329,874

The following graphs present our utility resource costs for the three months ended June 30 (dollars in millions):





Total resource costs in the graphs above include intracompany resource costs of $13.1 million and $26.6 million for the three months ended June 30, 2016 and June 30, 2015, respectively.

Total electric resource costs decreased $11.0 million for the second quarter of 2016 as compared to the second quarter of 2015 due to the following:

- a $1.8 million decrease in purchased power due to a decrease in the volume of power purchases (decreased costs $2.5 million), partially offset by an increase in wholesale prices (increased costs $0.7 million). The fluctuation in volumes and prices was primarily the result of our optimization activities during the quarter.
- a $0.5 million decrease from amortizations and deferrals of power costs.
- a $12.5 million decrease in fuel for generation primarily due to a decrease in thermal generation and a decrease in natural gas fuel prices.
- a $2.0 million increase in other fuel costs. This represents fuel and the related derivative instruments that were

purchased for generation but were later sold when conditions indicated that it was more economical to sell the fuel as part of the resource optimization process. When the fuel or related derivative instruments are sold, that revenue is included in sales of fuel.

- a $0.9 million increase in other electric resource costs primarily due to a benefit that was recorded during the second quarter of 2015 related to a capacity contract of Spokane Energy. This benefit was mostly deferred for probable future benefit to customers through the ERM and PCA in 2015.
- a $0.9 million increase in other regulatory amortizations.

Total natural gas resource costs decreased $33.7 million for the second quarter of 2016 as compared to the second quarter of 2015 due to following:

- a $35.9 million decrease in natural gas purchased due to a decrease in the price of natural gas (decreased costs $20.9 million) and a decrease in total therms purchased (decreased costs $15.0 million). Total therms purchased decreased due to a decrease in wholesale and retail sales.
- a $1.7 million increase from amortizations and deferrals of natural gas costs. This reflects lower natural gas prices and the deferral of lower costs which occurred in the current year for future rebate to customers.
- a $0.5 million increase in other regulatory amortizations.

Six months ended June 30, 2016 compared to the six months ended June 30, 2015

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

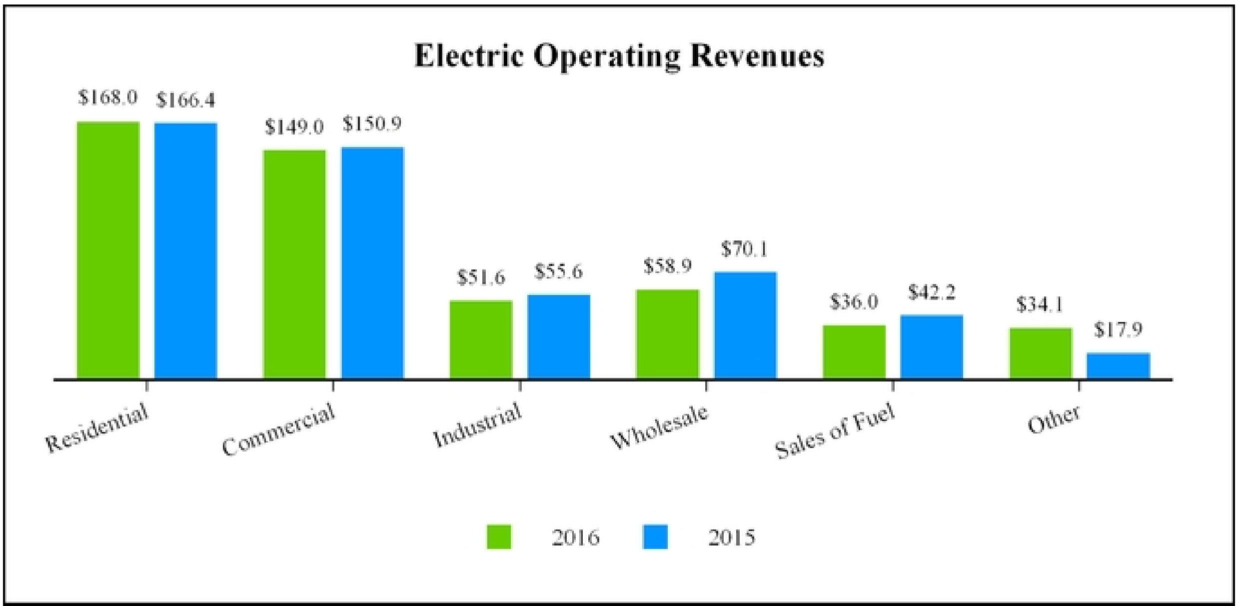
	Electric		Natural Gas		Intracompany		Total	
	2016	2015	2016	2015	2016	2015	2016	2015
Operating revenues	$ 497,593	$ 503,148	$ 236,365	$ 285,985	$ (31,170)	$ (44,352)	$ 702,788	$ 744,781
Resource costs	167,702	195,171	129,153	193,737	(31,170)	(44,352)	265,685	344,556
Gross margin	$ 329,891	$ 307,977	$ 107,212	$ 92,248	$ —	$ —	$ 437,103	$ 400,225

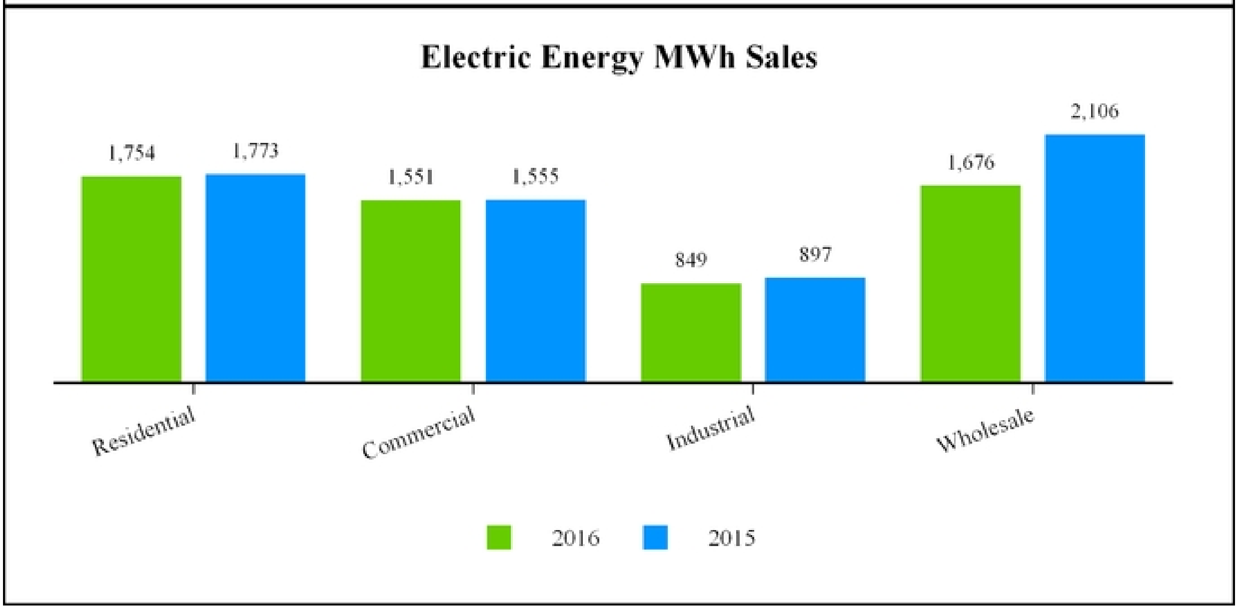
The gross margin on electric sales increased $21.9 million and the gross margin on natural gas sales increased $15.0 million. The increase in electric gross margin was primarily due to a general rate increase in Idaho, lower resource costs and the implementation of decoupling in Idaho, partially offset by a general rate decrease in Washington and lower retail loads. Weather was cooler than the prior year in the first quarter (which increased heating loads), warmer than the prior year in April and May (which reduced heating loads) and cooler than the prior year in June (which reduced cooling loads) but significantly warmer than normal for all periods. Retail electric loads decreased slightly as compared to prior year and the impact as compared to normal was mostly offset by decoupling mechanisms. See the table below for a comparison of the amounts recorded for decoupling by jurisdiction. For the six months ended June 30, 2016, we recognized a pre-tax benefit of $4.2 million under the ERM in Washington compared to a benefit of $5.7 million for the six months ended June 30, 2015.

The increase in natural gas gross margin was primarily due to general rate cases in each of our jurisdictions, lower natural gas resources costs, the implementation of decoupling mechanisms in Idaho and Oregon, and higher retail loads. Weather was cooler in the first quarter (which increased heating loads) and warmer in April and May (which reduced heating loads) as compared to the prior year, (overall increasing heating loads for the year-to-date) but warmer than normal. As such, retail natural gas loads increased as compared to prior year and the impact as compared to normal was mostly offset by decoupling mechanisms. See the table below for a comparison of the amounts recorded for decoupling by jurisdiction.

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 condensed consolidated financial statements but are included in the separate results for electric and natural gas presented below.

The following graphs present our utility electric operating revenues and megawatt-hour (MWh) sales for the six months ended June 30 (dollars in millions and MWhs in thousands):





The following table presents Avista Utilities' decoupling and customer earnings sharing mechanisms by jurisdiction that are included in utility electric operating revenues for the six months ended June 30 (dollars in thousands):

	Electric Operating Revenues	
	2016	2015
Washington		
Decoupling surcharge	$ 8,634	$ 1,832
Provision for earnings sharing (1)	2,169	(560)
Idaho		
Decoupling surcharge	$ 5,031	n/a
Provision for earnings sharing (2)	711	—

(1) The provision for earnings sharing in Washington in the six months ended June 30, 2016 resulted from a $2.5 million reduction in the 2015 provision for earnings sharing (which increased 2016 revenues), partially offset by a $0.3 million provision for the six months ended June 30, 2016.

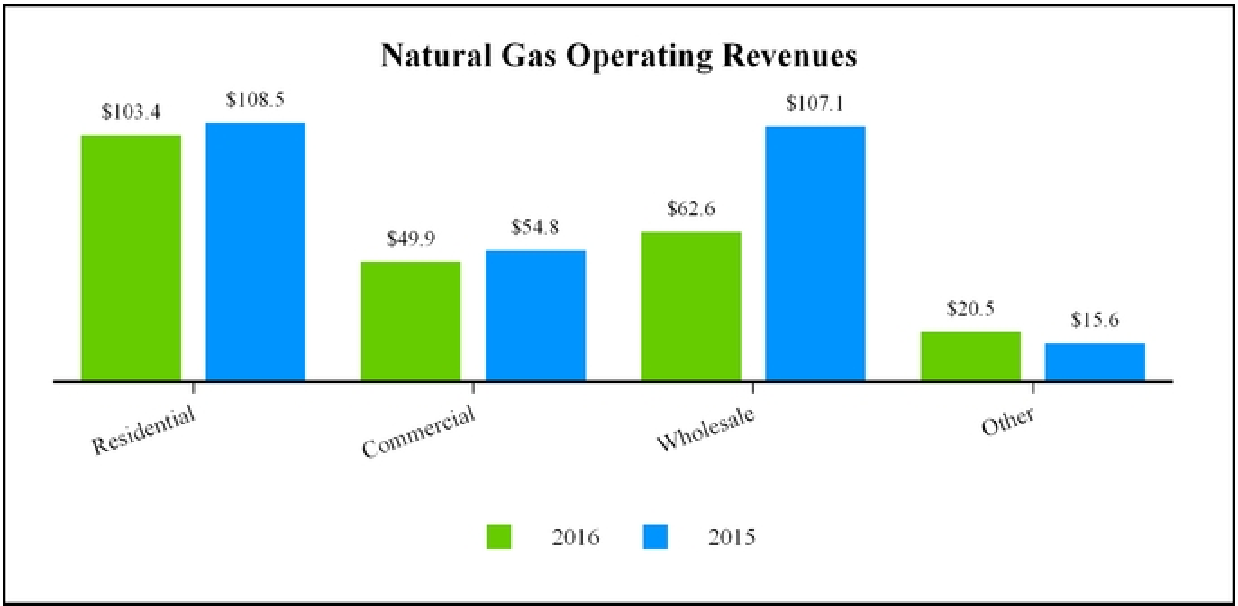
(2) The provision for earnings sharing in Idaho in the six months ended June 30, 2016 resulted from a reduction in the 2015 provision for earnings sharing (which increased 2016 revenues). Beginning in 2016 there is no longer an earning sharing mechanism in Idaho.

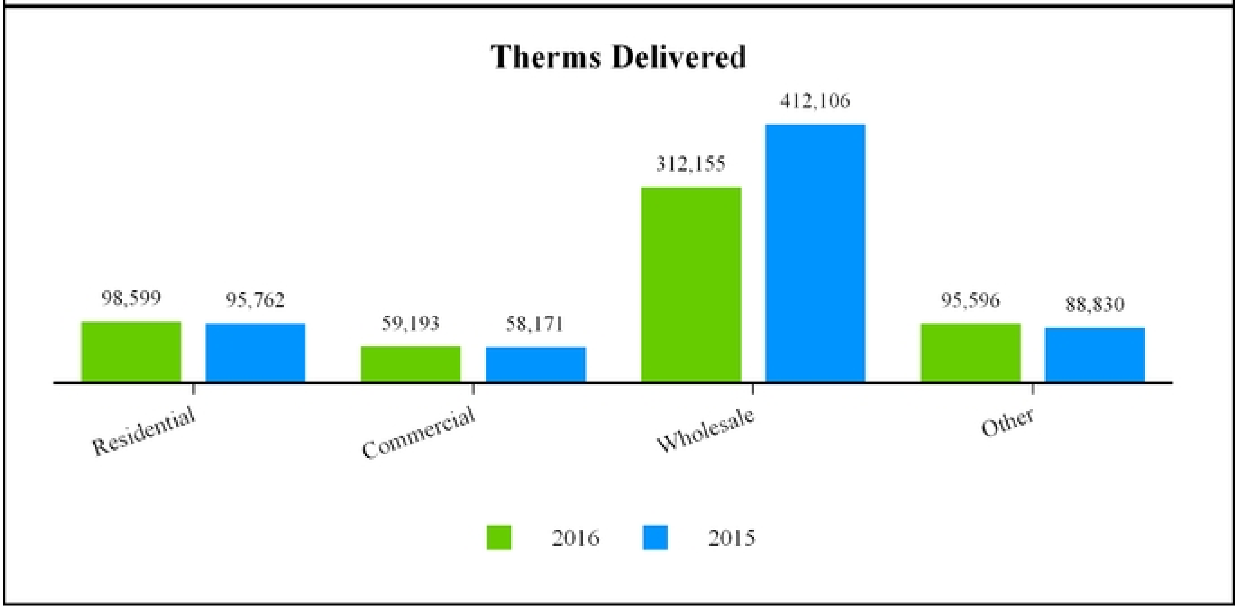
(n/a) This mechanism did not exist during this time period.

Total electric revenues decreased $5.5 million for the six months ended June 30, 2016 as compared to the six months ended June 30, 2015 due to the following:

- a $3.9 million decrease in retail electric revenue due to a decrease in total MWhs sold (decreased revenues $6.3 million), partially offset by an increase in revenue per MWh (increased revenues $2.4 million).
  - The increase in revenue per MWh was primarily due to a general rate increase in Idaho and the expiration of the ERM rebate in Washington, partially offset by a general rate decrease in Washington.
  - The decrease in total retail MWhs sold was the result of weather that was cooler in the first quarter (higher heating loads), warmer in April and May (lower heating loads) and cooler in June (lower cooling loads) as compared to the prior year (which overall decreased loads), partially offset by customer growth. Compared to the six months ended June 30, 2015, residential electric use per customer decreased 0.5 percent and commercial use per customer increased 0.7 percent. Heating degree days in Spokane were 18 percent below normal and 1 percent above the first six months of 2015. Year-to-date 2016 cooling degree days were 117, compared to 10 for the historical normal. However, cooling degree days were 54 percent below the prior year.
- an $11.2 million decrease in wholesale electric revenues due to a decrease in sales volumes (decreased revenues $15.1 million), partially offset by an increase in sales prices (increased revenues $3.9 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $6.2 million decrease in sales of fuel due to a decrease in sales of natural gas fuel as part of thermal generation resource optimization activities. For the six months ended June 30, 2016, $16.3 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For the six months ended June 30, 2015, $23.7 million of these sales were made to our natural gas operations.
- a $3.4 million decrease in the electric provision for earnings sharing (which increases revenues) primarily due to a $2.5 million reduction in the 2015 provision for earnings sharing in Washington and a $0.7 million reduction in the 2015 provision for earnings sharing in Idaho recorded in 2016.
- an $11.8 million increase in electric revenue due to decoupling, which reflected the implementation of a decoupling (FCA) mechanism in Idaho effective January 1, 2016 and lower retail revenues.

The following graphs present our utility natural gas operating revenues and therms delivered for the six months ended June 30 (dollars in millions and therms in thousands):





The following table presents Avista Utilities' decoupling and customer earnings sharing mechanisms by jurisdiction that are included in utility natural gas operating revenues for the six months ended June 30 (dollars in thousands):

	Natural Gas Operating Revenues	
	2016	2015
Washington		
Decoupling surcharge	$ 6,766	$ 4,904
Provision for earnings sharing	(536)	—
Idaho		
Decoupling surcharge	$ 2,126	n/a
Provision for earnings sharing	n/a	—
Oregon		
Decoupling surcharge	$ 1,858	n/a
Provision for earnings sharing	—	—

(n/a) This mechanism did not exist during this time period.

Total natural gas revenues decreased $49.6 million for the six months ended June 30, 2016 as compared to the six months ended June 30, 2015 primarily due to the following:

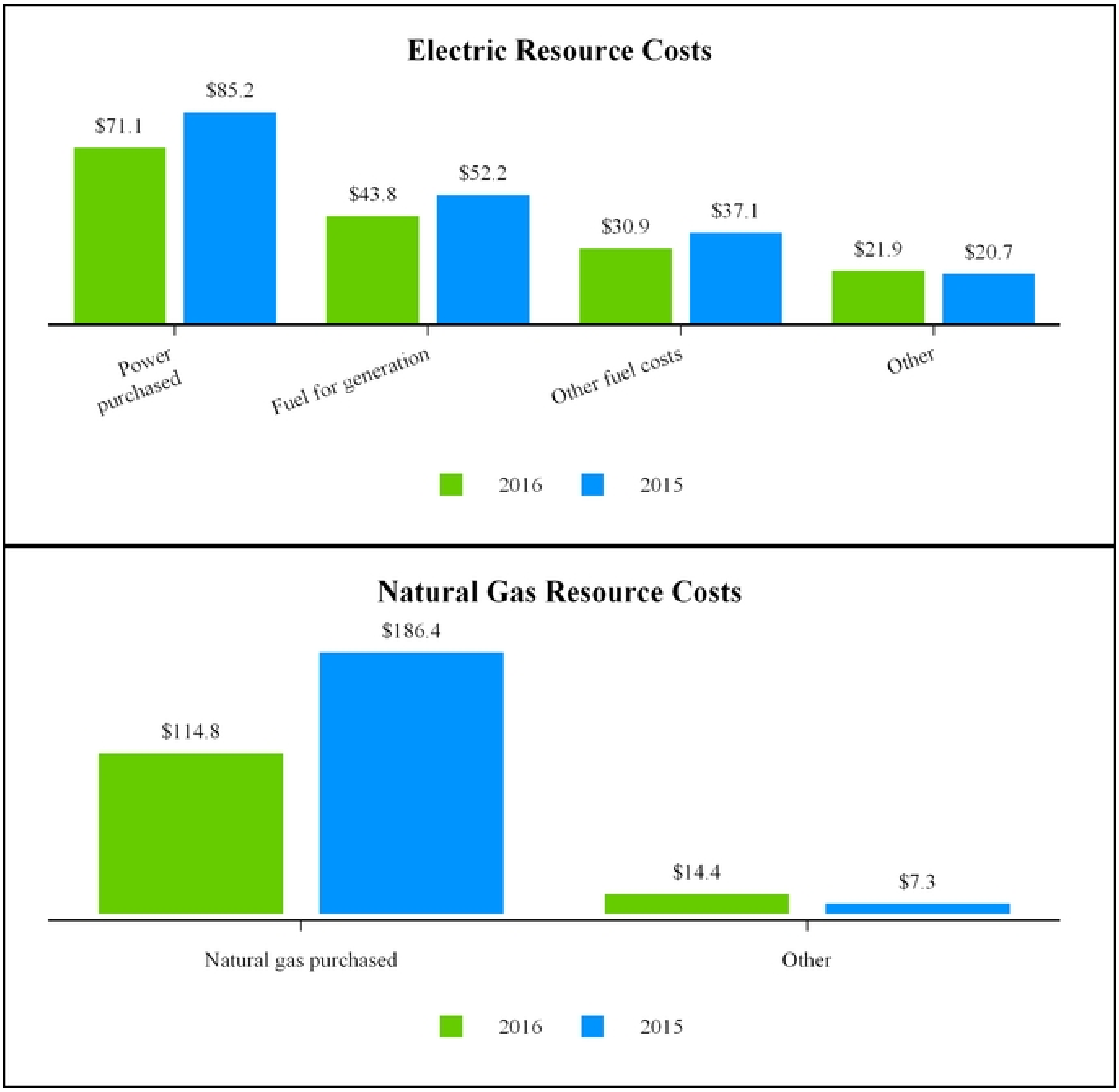
- a $10.6 million decrease in natural gas retail revenues due to lower retail rates (decreased revenues $15.0 million), partially offset by an increase in volumes (increased revenues $4.4 million).
  - Lower retail rates were due to PGAs, partially offset by general rate cases.
  - We sold more retail natural gas in the six months ended June 30, 2016 as compared to the six months ended June 30, 2015 due to cooler weather in the first quarter and customer growth, partially offset by warmer weather in April and May. Compared to the first six months of 2015, residential natural gas use per customer increased 3 percent and commercial use per customer increased 1 percent. Heating degree days in Spokane were 18 percent below normal and 1 percent above the first six months of 2015. Heating degree days in Medford were 19 percent below normal and 1 percent below the first six months of 2015.
- a $44.5 million decrease in wholesale natural gas revenues due to a decrease in prices (decreased revenues $24.4 million) and a decrease in volumes (decreased revenues $20.1 million). In the six months ended June 30, 2016, $14.9 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In the six months ended June 30, 2015, $20.7 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.
- a $5.8 million increase for natural gas decoupling revenues due primarily to the implementation of decoupling mechanisms in Idaho and Oregon.

Under GAAP, any decoupling revenue amounts that will not be collected within 24 months of the current period are not allowed to be recognized as revenue until the period in which revenue recognition criteria are met. As a result, we have reached the maximum amount of natural gas decoupling revenue that we can recognize during 2016 in Washington and Idaho and we are close to the maximum amount in Oregon. Any additional revenues that would normally be recognized under the decoupling mechanisms for 2016, had the maximum amounts not been reached, will be recognized in a future period.

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

	Electric Customers		Natural Gas Customers	
	2016	2015	2016	2015
Residential	329,810	326,131	299,966	295,269
Commercial	41,698	41,271	34,874	34,211
Interruptible	—	—	38	34
Industrial	1,347	1,354	256	262
Public street and highway lighting	555	536	—	—
Total retail customers	373,410	369,292	335,134	329,776

The following graphs present our utility resource costs for the six months ended June 30 (dollars in millions):



Total resource costs in the graphs above include intracompany resource costs of $31.2 million and $44.4 million for the six months ended June 30, 2016 and June 30, 2015, respectively.

Total electric resource costs decreased $27.5 million for the six months ended June 30, 2016 as compared to the six months ended June 30, 2015 due to the following:

- a $14.1 million decrease in purchased power due to a decrease in the volume of power purchases (decreased costs $5.7 million) and a decrease in wholesale prices (decreased costs $8.4 million). The fluctuation in volumes and prices was primarily the result of our optimization activities during the quarter.
- a $7.0 million decrease from amortizations and deferrals of power costs.
- an $8.4 million decrease in fuel for generation due to a decrease in thermal generation and a decrease in natural gas fuel prices.
- a $6.2 million decrease in other fuel costs.

- a $5.7 million increase in other electric resource costs primarily due to a benefit that was recorded during 2015 related to a capacity contract of Spokane Energy. This benefit was mostly deferred for probable future benefit to customers through the ERM and PCA.
- a $2.5 million increase in other regulatory amortizations.

Total natural gas resource costs decreased $64.5 million for the six months ended June 30, 2016 as compared to the six months ended June 30, 2015 due to following:

- a $71.6 million decrease in natural gas purchased due to a decrease in the price of natural gas (decreased costs $48.6 million) and a decrease in total therms purchased (decreased costs $23.0 million). Total therms purchased decreased due to a decrease in wholesale sales, partially offset by an increase in retail sales.
- a $5.4 million increase from amortizations and deferrals of natural gas costs. This reflects lower natural gas prices and the deferral of lower costs for future rebate to customers.
- a $1.7 million increase in other regulatory amortizations.

Results of Operations - Alaska Electric Light and Power Company

Three months ended June 30, 2016 compared to the three months ended June 30, 2015 and six months ended June 30, 2016 compared to the six months ended June 30, 2015

Net income for AEL&P was $1.1 million for the three months ended June 30, 2016 compared to $0.9 million for the three months ended June 30, 2015. Net income was $4.0 million for the six months ended June 30, 2016 compared to $3.6 million for the six months ended June 30, 2015.

The increase in earnings for both the quarter and year-to-date at AEL&P was primarily due to a slight increase in gross margin, offset by slightly higher operating expenses. In addition there was an increase in equity-related AFUDC (increased earnings) due to the construction of an additional back-up generation plant planned to be completed in 2016.

The increase in gross margin was primarily related to a decrease in resource costs associated with the Snettisham hydroelectric project (due to a refinancing transaction during the second half of 2015 which lowered interest costs under the take-or-pay power purchase agreement) as well as an increase in sales to commercial customers, partially offset by a decrease in sales to residential and governmental customers.

AEL&P has a relatively stable load profile as it does not have a large population of customers in its service territory with electric heating and cooling requirements; therefore, its revenues are not as sensitive to weather fluctuations as Avista Utilities. However, AEL&P does have higher winter rates for its customers during the peak period of November through May of each year, which drives higher revenues during those periods.

Results of Operations - Other Businesses

Net losses for our other businesses were $0.6 million for the three months ended June 30, 2016 compared to $0.4 million for the three months ended June 30, 2015. Net losses were $0.9 million for the six months ended June 30, 2016 compared to $0.9 million for the six months ended June 30, 2015.

Net losses for both the second quarter and the year-to-date were primarily related to slight increases in corporate costs (including costs associated with exploring strategic opportunities) compared to the respective periods in the prior year, partially offset by a slight increase in net income at METALfx for both the quarter and year-to-date.

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. Our critical accounting policies that require the use of estimates and assumptions were discussed in detail in the 2015 Form 10-K and have not changed materially from that discussion.

Liquidity and Capital Resources

Overall Liquidity

Our sources of overall liquidity and the requirements for liquidity have not materially changed in the six months ended June 30, 2016. See the 2015 Form 10-K for further discussion.

As of June 30, 2016, we had $194.2 million of available liquidity under the Avista Corp. committed line of credit and $25.0 million under the AEL&P committed line of credit. With our $400.0 million credit facility that expires in April 2021 and AEL&P's $25.0 million credit facility that expires in November 2019, we believe that we have adequate liquidity to meet our needs for the next 12 months.

Review of Cash Flow Statement

Overall

During the six months ended June 30, 2016, positive cash flows from operating activities were $156.0 million and we received proceeds from the issuance of common stock of $47.2 million. Cash requirements included utility capital expenditures of $182.8 million, net cash collateral for derivative instruments (primarily interest rate swaps) of $83.5 million, dividends of $43.3 million and contributions to our pension plan of $8.0 million.

Operating Activities

Net cash provided by operating activities was $156.0 million for the six months ended June 30, 2016 compared to $232.1 million for the six months ended June 30, 2015. Net income was $85.0 million for the six months ended June 30, 2016 compared to $71.7 million for the six months ended June 30, 2015. In addition to the fluctuation in net income, the provision for deferred income taxes was $56.7 million for the six months ended June 30, 2016 compared to $6.2 million for the six months ended June 30, 2015. The change in the provision for deferred income taxes was primarily related to deferred taxes on property, plant and equipment, investment tax credits associated with our Nine Mile Falls hydroelectric capital project and deferred taxes on the decoupling regulatory assets.

Net cash used by fluctuations in certain current assets and liabilities was $65.1 million for the six months ended June 30, 2016, compared to net cash provided of $56.1 million for the six months ended June 30, 2015. The net cash used by certain current assets and liabilities during the six months ended June 30, 2016, primarily reflects net cash outflows related to an increase in deposits with counterparties (primarily due to a decrease in the fair value of outstanding interest rate swaps, which required additional collateral), a seasonal decrease in accounts payable and an increase in other current assets. These negative cash flows were partially offset by net cash inflows related to a decrease in income taxes receivable and a seasonal decrease in accounts receivable and stored natural gas.

The net cash provided by certain current assets and liabilities during the first half of 2015 primarily reflects positive cash flows related to a decrease in income taxes receivable (which resulted from the receipt of a tax refund in 2015 from our election of federal tax tangible property regulations in 2014) and a seasonal decrease in accounts receivable and stored natural gas. These positive cash flows were partially offset by net cash outflows related to a seasonal decrease in accounts payable.

Net deferrals of power and natural gas costs increased operating cash flows by $10.0 million for the six months ended June 30, 2016 compared to $11.4 million for the six months ended June 30, 2015. Our regulatory assets associated with our decoupling regulatory deferrals increased by $24.8 million for the six months ended June 30, 2016 compared to $6.8 million for the six months ended June 30, 2015 primarily related to the implementation of decoupling mechanisms in Idaho and Oregon during 2016, as well as weather that was warmer than normal during the first half of 2016. Contributions to our defined benefit pension plan were $8.0 million for each of the first halves of 2016 and 2015.

Investing Activities

Net cash used in investing activities was $206.6 million for the six months ended June 30, 2016, compared to $175.6 million for the six months ended June 30, 2015. During the first half of 2016, we paid $182.8 million for utility capital expenditures compared to $177.8 million for the first half of 2015. In addition, during the first half of 2016, our subsidiaries issued $9.7 million of notes receivable and made a $5.0 million investment in another company.

Financing Activities

Net cash provided by financing activities was $53.7 million for the six months ended June 30, 2016 compared to net cash used of $62.4 million for the six months ended June 30, 2015. During the first half of 2016, short-term borrowings on Avista Corp.'s committed line of credit increased $55.0 million, compared to a decrease of $15.0 million in the first half of 2015. Cash dividends paid to Avista Corp. shareholders increased to $43.3 million (or $0.685 per share) for the first half of 2016 from $41.3 million (or $0.66 per share) for the first half of 2015. During the six months ended June 30, 2016, we issued $47.2 million of common stock, almost all of which was under sales agency agreements. During the six months ended June 30, 2015, we issued $1.1 million of common stock and repurchased $2.9 million of common stock.

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 June 30, 2016 and December 31, 2015 (dollars in thousands):

	June 30, 2016		December 31, 2015	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt and capital leases	$ 93,227	2.8%	$ 93,167	2.9%
Short-term borrowings	160,000	4.7%	105,000	3.2%
Long-term debt to affiliated trusts	51,547	1.5%	51,547	1.6%
Long-term debt and capital leases	1,479,668	43.5%	1,480,111	45.4%
Total debt	1,784,442	52.5%	1,729,825	53.1%
Total Avista Corporation shareholders' equity	1,617,027	47.5%	1,528,626	46.9%
Total	$ 3,401,469	100.0%	$ 3,258,451	100.0%

Our shareholders' equity increased $88.4 million during the first six months of 2016 primarily due to net income and the issuance of common stock through our sales agency agreements, partially offset by dividends.

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.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. We exercised a two-year option in May 2016 to extend the maturity of the facility agreement to April 2021. As of June 30, 2016, there were $160.0 million of cash borrowings and $45.8 million in letters of credit outstanding (which were primarily issued as collateral for our commodity and interest rate swap derivatives), leaving $194.2 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 June 30, 2016, we were in compliance with this covenant with a ratio of 52.5 percent.

AEL&P has a $25.0 million committed line of credit that expires in November 2019. As of June 30, 2016, there were no borrowings or letters of credit outstanding under this committed line of credit.

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 June 30, 2016, AEL&P was in compliance with this covenant with a ratio of 56.1 percent.

In March 2016, we entered into four separate sales agency agreements under which Avista Corp.'s sales agents may offer and sell up to 3.8 million new shares of Avista Corp.'s common stock, no par value, from time to time. The sales agency agreements expire on February 29, 2020. In the six months ended June 30, 2016, 1.2 million shares were issued under these agreements resulting in total net proceeds of $46.3 million, leaving 2.6 million shares remaining to be issued.

For 2016, we expect to issue approximately $75.0 million of common stock (including the $47.2 million already issued) and $175.0 million of long-term debt in order to fund capital expenditures, refinance $90.0 million of maturing long-term debt and maintain an appropriate capital structure. We expect to extend $70.0 million of our outstanding $90.0 million term loan that otherwise would mature in August until December 2016 when our new long-term debt is issued.

After considering the expected issuances of long-term debt and common stock during 2016, we expect net cash flows from operating activities, together with cash available under our committed line of credit agreements, to provide adequate resources to fund capital expenditures, dividends, and other contractual commitments.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under Avista Corp.'s committed line of credit were as follows as of and for the six months ended June 30 (dollars in thousands):

	2016	2015
Borrowings outstanding at end of period	$ 160,000	$ 90,000
Letters of credit outstanding at end of period	$ 45,795	$ 34,379
Maximum borrowings outstanding during the period	$ 160,000	$ 137,500
Average borrowings outstanding during the period	$ 118,832	$ 76,796
Average interest rate on borrowings during the period	1.22%	0.97%
Average interest rate on borrowings at end of period	1.22%	0.94%

There were no borrowings outstanding under AEL&P's committed line of credit as of June 30, 2016 and June 30, 2015.

As of June 30, 2016, 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.

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. Our estimated capital expenditures for 2016, 2017 and 2018 have not materially changed during the six months ended June 30, 2016. See the 2015 Form 10-K as well as our first quarter 2016 Form 10-Q for further information.

Off-Balance Sheet Arrangements

As of June 30, 2016, we had $45.8 million in letters of credit outstanding under our $400.0 million committed line of credit, compared to $44.6 million as of December 31, 2015.

Pension Plan

Avista Utilities

In the six months ended June 30, 2016 we contributed $8.0 million to the pension plan and we expect to contribute $12.0 million total in 2016. We expect to contribute a total of $60.0 million to the pension plan in the period 2016 through 2020, with annual contributions 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 5 of the Notes to Condensed Consolidated Financial Statements" for additional information regarding the pension plan.

Contractual Obligations

Our future contractual obligations have not materially changed during the six months ended June 30, 2016 except that in April 2016, we entered into an agreement to invest in a company for a total of $10.0 million. The investment was $5.0 million for partial equity ownership in the company and $5.0 million in a short-term convertible loan. We issued the full $10.0 million to this company in April 2016. See the 2015 Form 10-K for other contractual obligations.

Environmental Issues and Contingencies

Our environmental issues and contingencies disclosures have not materially changed except for the following during the six months ended June 30, 2016. See the 2015 Form 10-K for all other environmental issues and contingencies.

Clean Air Act

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 Colstrip. The Complaint alleged certain violations of the Clean Air Act. On July 12, 2016, all of the parties to this action filed a Consent Decree with the Court settling all claims contained in the Complaint. See “Sierra Club and Montana Environmental Information Center Complaint Against the Owners of Colstrip” in “Note 11 of the Notes to Condensed Consolidated Financial Statements” for further information on this matter.

Hazardous Air Pollutants

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. At the time of issuance in 2012, we examined the existing emission control systems of Colstrip Units 3 & 4, the only units in which we are a minority owner, and concluded that the existing emission control systems should be sufficient to meet mercury limits. For the remaining portion of the rule that utilized Particulate Matter as a surrogate for air toxics (including metals and acid gases), the Colstrip owners reviewed recent stack testing data and expected that no additional emission control systems would be needed for Units 3 & 4 MATS compliance.

On June 29, 2015, the Supreme Court held that the EPA's interpretation of MATS was unreasonable when it deemed cost irrelevant for MATS regulation. The EPA made a final supplemental determination on April 14, 2016, determining that an inclusion of cost considerations supported its original regulation.

Climate Change - State Legislation and State Regulatory Activities

The Washington State Department of Ecology (Ecology) has commenced rulemaking, using its existing authorities, to cap and reduce carbon emissions across the State of Washington in pursuit of the State’s carbon goals, which were enacted in 2008 by the Washington State Legislature (Legislature). The rule applies to sources of annual greenhouse emissions in excess of 100,000 tons for the first compliance period of 2017 through 2019; this threshold incrementally decreases to 70,000 metric tons beginning in 2035. The rule affects stationary sources and transportation fuel suppliers, as well as natural gas distribution companies. Ecology has identified approximately 30 entities responsible for 60 percent of the state’s emission sources that would be regulated under the proposed rule. The proposed rule would only apply to Avista Corp. as a natural gas distribution company, for the emissions associated with the use of the natural gas we provide our customers. Ecology anticipates that it will adopt the rule before September 2016.

An Initiative to the Legislature (I-732), which would impose a carbon tax on fossil-fueled generation and natural gas distribution, as well as on transportation fuels, was submitted to the Legislature in January 2016. As an Initiative to the Legislature, given the Legislature’s failure to act upon the measure, I-732 has been referred to the General Election ballot. While we cannot predict the eventual outcome of actions arising out of initiatives, proposed legislation and regulatory actions at this time nor estimate the effect thereof, we will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to our utility operations.

In Oregon, legislation was enacted this year which requires Portland General Electric and Pacificorp to remove coal-fired generation from their rate-base by 2030. This legislation does not directly relate to Avista Corp. because Avista Corp. is not an electric utility in Oregon. However, because these two utilities, along with Avista Corp., hold minority interests in Colstrip, the legislation could indirectly impact Avista Corp., though specific impacts cannot be identified at this time. While the legislation requires Portland General Electric and Pacificorp to eliminate Colstrip from their rates, they would be permitted to sell the output of their shares of Colstrip into the wholesale market or, as is the case with Pacificorp, reallocate the plant to other states. We cannot predict the eventual outcome of actions arising from this legislation at this time or estimate the effect thereof on Avista Corp.; however, we will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to our generation assets.

Other

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

Enterprise Risk Management

The material risks to our businesses were discussed in our 2015 Form 10-K and have not materially changed during the six months ended June 30, 2016. Refer to the 2015 Form 10-K for further discussion of our risks and the mitigation of those risks.

Financial Risk

Our financial risks have not materially changed during the six months ended June 30, 2016. Refer to the 2015 Form 10-K. The financial risks included below are required interim disclosures, even if they have not materially changed from December 31, 2015.

Interest Rate Risk

We use a variety of techniques to manage our interest rate risks. We have an interest rate risk policy and have established a policy to limit 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. The 2015 Form 10-K contains a discussion of risk management policies and procedures. See "Note 4 of the Notes to Condensed Consolidated Financial Statements" for a summary of our interest rate swaps outstanding as of June 30, 2016 and December 31, 2015.

In anticipation of issuing long-term debt in the future, we entered into three interest rate swap derivatives in July 2016, hedging an aggregate notional amount of $30.0 million with mandatory cash settlement dates in 2016, 2018 and 2019.

Credit Risk

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 June 30, 2016, we had cash deposited as collateral in the amount of $29.2 million and letters of credit of $17.5 million outstanding related to our energy derivative contracts. Price movements and/or a downgrade in our credit ratings could further impact 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 June 30, 2016, we would potentially be required to post additional collateral of up to $4.2 million. This amount is different from the amount disclosed in “Note 4 of the Notes to Condensed Consolidated Financial Statements” because, while this analysis includes contracts that are not considered derivatives in addition to the contracts considered in Note 4, this analysis takes into account contractual threshold limits that are not considered in Note 4. Without contractual threshold limits, we would potentially be required to post additional collateral of $4.8 million.

Under the terms of interest rate swap derivatives 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 June 30, 2016, we had interest rate swap derivatives outstanding with a notional amount totaling $555.0 million and we had deposited cash in the amount of $117.0 million and letters of credit of $22.0 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 derivatives outstanding at June 30, 2016, we would be required to post additional collateral of $18.5 million.

Energy Commodity Risk

Our energy commodity risks have not materially changed during the six months ended June 30, 2016, except as discussed below. Refer to the 2015 Form 10-K. The following table presents energy commodity derivative fair values as a net asset or (liability) as of June 30, 2016 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)
2016	$ (1,695)	$ (2,410)	$ 1,267	$ (17,079)	$ 57	$ 5,460	$ (845)	$ 8,332
2017	(4,949)	231	(522)	(8,141)	(29)	2,518	(1,842)	(1,586)
2018	(4,779)	—	—	(3,114)	(55)	(523)	(1,243)	(121)
2019	(3,117)	—	(72)	(2,269)	(20)	—	(1,106)	—
2020	—	—	(23)	(122)	—	—	(1,271)	—
Thereafter	—	—	—	—	—	—	(728)	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2015 that are expected to be delivered 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)
2016	$ (6,928)	$ (14,988)	$ (5,895)	$ (41,006)	$ 82	$ 28,857	$ 173	$ 22,445
2017	(6,403)	36	(1,050)	(9,473)	(23)	3,971	(1,125)	313
2018	(5,614)	—	—	(3,554)	(50)	—	(1,172)	(162)
2019	(3,072)	—	(22)	(1,964)	(44)	—	(1,220)	—
2020	—	—	35	(18)	—	—	(1,130)	—
Thereafter	—	—	—	—	—	—	(679)	—

(1) Physical transactions represent commodity transactions in which we will take or make delivery of either electricity or natural gas; financial transactions represent derivative instruments with delivery of cash in the amount of the benefit or cost but with no physical delivery of the commodity, such as futures, swaps, options, or forward contracts.

The electric and natural gas derivative contracts above will be included in either net power supply costs or net 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 reflected in retail rates from customers.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The information required by this item is set forth in the Enterprise Risk Management section of "Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations" and is incorporated herein by reference.

Item 4. 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) (Act) that are designed 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. With the participation of the Company’s principal executive officer and principal financial officer, the Company's management 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. Based upon this 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 June 30, 2016.

There have been no changes in the Company's internal control over financial reporting that occurred during the second quarter of 2016 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. Other Information

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Please refer to the 2015 Form 10-K for disclosure of risk factors that could have a significant impact on our results of operations, financial condition or cash flows and could cause actual results or outcomes to differ materially from those discussed in our reports filed with the Securities and Exchange Commission (including this Quarterly Report on Form 10-Q), and elsewhere. These risk factors have not materially changed from the disclosures provided in the 2015 Form 10-K.

In addition to these risk factors, see also “Forward-Looking Statements” and "Item 2. Management’s Discussion and Analysis: Regulatory Matters: 2015 Washington General Rate Cases" for additional factors which could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) Not applicable

(b) Not applicable

(c) Not applicable

Item 4. Mine Safety Disclosures

Not applicable.

Item 6. Exhibits

12	Computation of ratio of earnings to fixed charges*
15	Letter Re: Unaudited Interim Financial Information*
31.1	Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002)*
31.2	Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002)*
32	Certification of Corporate Officers (Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)**
101	The following financial information from the Quarterly Report on Form 10−Q for the period ended June 30, 2016, formatted in XBRL (Extensible Business Reporting Language) and filed electronically herewith: (i) the Condensed Consolidated Statements of Income; (ii) Condensed Consolidated Statements of Comprehensive Income; (iii) the Condensed Consolidated Balance Sheets; (iv) the Condensed Consolidated Statements of Cash Flows; (v) the Condensed Consolidated Statements of Equity; and (vi) the Notes to Condensed Consolidated Financial Statements.*

* Filed herewith.

** Furnished herewith.

SIGNATURE

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

AVISTA CORPORATION
(Registrant)

Date: August 2, 2016

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

Exhibit 12

AVISTA CORPORATION

Computation of Ratio of Earnings to Fixed Charges
Consolidated
(Thousands of Dollars)

	Six months ended	Years Ended December 31				
	June 30, 2016	2015	2014	2013	2012	2011
Fixed charges, as defined:						
Interest charges	$ 42,764	$ 80,613	$ 74,025	$ 73,772	$ 71,843	$ 69,536
Amortization of debt expense and premium - net	1,697	3,415	3,635	3,813	3,803	4,617
Interest portion of rentals	671	1,287	1,187	1,146	1,294	1,139
Total fixed charges	$ 45,132	$ 85,315	$ 78,847	$ 78,731	$ 76,940	$ 75,292
Earnings, as defined:						
Pre-tax income from continuing operations	$ 132,007	$ 185,619	$ 192,106	$ 162,347	$ 116,567	$ 139,438
Add (deduct):						
Capitalized interest	(1,751)	(3,546)	(3,924)	(3,676)	(2,401)	(2,942)
Total fixed charges above	45,132	85,315	78,847	78,731	76,940	75,292
Total earnings	$ 175,388	$ 267,388	$ 267,029	$ 237,402	$ 191,106	$ 211,788
Ratio of earnings to fixed charges	3.89	3.13	3.39	3.02	2.48	2.81

Exhibit 15

August 2, 2016

Avista Corporation
Spokane, Washington

We have reviewed, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the unaudited interim financial information of Avista Corporation and subsidiaries for the periods ended June 30, 2016 and 2015, as indicated in our report dated August 2, 2016; because we did not perform an audit, we expressed no opinion on that information.

We are aware that our report referred to above, which is included in your Quarterly Report on Form 10-Q for the quarter ended June 30, 2016, is incorporated by reference in Registration Statement Nos. 333-33790, 333-126577, 333-179042 and 333-208986 on Form S-8 and in Registration Statement Nos. 333-187306 and 333-209714 on Form S-3.

We are also aware that the aforementioned report, pursuant to Rule 436(c) under the Securities Act of 1933, is not considered a part of the Registration Statements prepared or certified by an accountant or a report prepared or certified by an accountant within the meaning of Sections 7 and 11 of that Act.

/s/ Deloitte & Touche LLP

Seattle, Washington

Exhibit 31.1

CERTIFICATION

I, Scott L. Morris, certify that:

1. I have reviewed this report on Form 10-Q 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: August 2, 2016

/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-Q 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: August 2, 2016

/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 Quarterly Report on Form 10-Q for the quarter ended June 30, 2016 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: August 2, 2016

/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