Annual Report 2017

Thinking Bigger
for Better Communities

Innovating Forward

"BUSINESS AS USUAL" AT AVISTA IS NOT USUAL FOR MOST BUSINESSES. GOING BEYOND THE EXPECTED IS THE MINDSET OF OUR WHOLE COMPANY, WHERE WE CHALLENGE OURSELVES AND EACH OTHER TO THINK BIGGER THAN WHAT WE THOUGHT POSSIBLE, EVERY DAY.

TO OUR SHAREHOLDERS

Our industry is changing each year, and this year, change was front and center for us. We embraced this change, as we do at Avista. Through thoughtful and deliberate efforts, we shaped the framework for a future partnership with Hydro One that is a win for all stakeholders.

In July, we announced the proposed merger with Hydro One of Ontario, Canada. In a consolidating industry, this partnership makes sense for all of us — our shareholders, employees, customers and communities. The decision to team up with Hydro One, at a time of strength and growth for our company, is a unique opportunity to preserve our identity and strong legacy while allowing us to significantly define and control our future operations. Hydro One provides additional scale, helping us build a stronger foundation for our future and augmenting available resources that allow us to continue investing in our energy infrastructure and technology.

VALUE FOR ALL STAKEHOLDERS THROUGH A PARTNERSHIP WITH HYDRO ONE

- Our shareholders will receive solid value, with an attractive price of $53 per share at the time of close. Demonstrating strong support, shareholders approved the acquisition on Nov. 21, 2017, with 77 percent of the outstanding shares entitled to vote on the proposal voting 98 percent in favor of the acquisition.
- Our customers will continue to receive high quality, safe and reliable energy services at a reasonable cost. We'll remain local, with local headquarters and local leadership.
- Our communities will continue to benefit from the critical philanthropic and economic development support we provide. In fact, we'll be able to do even more. Hydro One has committed to nearly doubling our current levels of community contributions by providing a $2 million annual contribution to the Avista Foundation.
- Our employees will see a continuation of the company essentially as it is today.

In January 2018, FERC provided its approval of the merger. We've submitted applications for regulatory approval in five states, which are still pending. We've requested regulatory approval from state utility commissions by Aug. 14, 2018. Pending these approvals, as well as approval from the Federal Communications Commission, clearance by the Committee on Foreign Investment in the United States, and compliance with applicable requirements under the U.S. Hart-Scott-Rodino

HEATHER ROSENTRATER, VP ENERGY DELIVERY, IS A KEY LEADER IN AVISTA'S INNOVATION EFFORTS LIKE URBANOVA AND GRID MODERNIZATION.

Antitrust Improvements Act, we expect that the transaction will close in the second half of 2018.

How we work, make decisions and engage with our customers and communities will not change as a result of this acquisition. We will remain focused on providing the same levels of high-quality service for customers, delivering on our core strategies and contributing to our communities in meaningful ways.

We won't be complacent.

While the industry continues to transform, we continue to help shape the future. We are a company with a long history of innovation and service. With this foundation, we think bigger to meet the expectations of our customers, strengthen our communities and engage our employees.

AS PART OF URBANOVA'S SMART AND CONNECTED STREETLIGHT PILOT, SENSOR PACKAGES WERE INSTALLED ON 10 STREETLIGHTS IN THE UNIVERSITY DISTRICT. THESE SENSORS MEASURE AIR QUALITY AND WILL HELP RESEARCHERS ASSESS ITS ROLE IN A HEALTHY CITY.

BEYOND ENERGY

Customer satisfaction is key to our success. When customers are informed and engaged with their energy choices, the benefits extend through the entire community. Paramount to customer satisfaction is anticipating their needs and offering choices to ensure we are their trusted energy advisor.

Through programs such as our Electric Vehicle Supply Equipment (EVSE) program, the Solar Select program and the launch of our new, more user-friendly website, we are providing solutions that benefit both the customer and the company and are engaging with our customers in diverse ways.

As a testament to our outstanding customer care, in April we received Edison Electric Institute's 2017 National Key Accounts Award for Customer Service, selected by customers as one of eight companies from 700 across the country, including Microsoft and Walmart. This award looked at innovative offerings, ease of incentive programs, communications and customer support before, during and after outages. We're honored to be one of the few utilities to receive this award.

BRIDGING COMMUNITIES. CONVENING IDEAS.

When our communities thrive, we all benefit. Bridging communities means leveraging intentional innovation and strategic partnerships to improve the lives of those we serve. Avista can be a catalyst for community and economic growth by recognizing projects we can support and convening resources and community leadership.

Urbanova, the smart city living laboratory in Spokane's University District, is a collaboration of strategic partnerships to create healthier communities, stronger economies, smarter infrastructure and a more sustainable future. As a founding partner, we're helping develop and test smart city applications and solutions that can shape the future. This year, as part of Urbanova's Smart and Connected Streetlights pilot, we installed sensors on streetlights in the University District that monitor air quality and other conditions. Researchers may use the collected data to inform future health initiatives for the community. We're excited about what's to come as part of Urbanova, including a Shared Energy Economy pilot that will create a microgrid and facilitate energy sharing among buildings in the University District.

THINK BIG. CREATE. MOVE SWIFTLY. SUCCEED.

Avista employees are hard-working, creative and dedicated. Their commitment and excellence is evident in everything we do. We ask them to think big, create and move swiftly. We nurture an entrepreneurial spirit among employees and give them room to turn good ideas into viable business possibilities. In return, Avista provides opportunities for professional development and success in a culture that engages all employees. Because when they do well, Avista does well, too.

MYAVISTA.COM LAUNCHED IN JULY WITH ADDITIONAL TOOLS, ENHANCED MOBILE CAPABILITIES AND IMPROVED SECURITY.

AN OVERVIEW OF 2017 FINANCIAL RESULTS

Our financial results this year were in line with expectations. Customer growth, lower resource costs and lower operating expenses were offset by the impact of federal income tax law changes and costs associated with the proposed acquisition by Hydro One.

Consolidated earnings were $1.79 per diluted share, with net income of $115.9 million for the year ended Dec. 31, 2017.

Acquisition costs reduced earnings by $0.19 per diluted share. The impact of federal income tax law changes on deferred income tax balances associated with subsidiaries and non-utility operations reduced earnings $0.16 per diluted share. Tax impacts paid for by customers will be returned to customers, through the rate-making process.

Our balance sheet and credit ratings remain healthy. At year-end, Avista Corp. had $260.6 million of available liquidity under our $400 million line of credit. We added cost-effective long-term debt through the private placement market by issuing $90 million of Avista Corp. first mortgage bonds, bearing an interest rate of 3.91 percent (4.55 percent effective interest rate), which will mature in December 2047.

Long-term corporate earnings growth of 4 percent to 5 percent continues to be our target. We believe earnings growth will come through our focus on updating and replacing aging infrastructure, continued effective cost management, investment in essential digital technologies and other growth platforms. Our projection for customer and load growth remains near 1 percent.

And, I'm pleased to note, that in 2017 the board of directors raised the dividend on Avista Corp. common stock for the 15th consecutive year, for an annualized dividend of $1.43.

REGULATED OPERATIONS

AVISTA UTILITIES

Avista Utilities contributed $1.77 per diluted share to earnings in 2017. Continuing our investment in replacing and updating aging infrastructure resulted in total capital costs of $405.9 million for the year. We plan to continue making capital investments near this level in 2018 and 2019 to maintain the reliability and strength of our electric and natural gas energy systems.

The timely recovery of these costs is essential to earning an adequate return on our shareholders' investment.

In Washington, we filed electric and natural gas general rate requests on May 26. These requests included a three-year rate plan and are pending before the utility commission. We expect a decision no later than the end of April 2018.

In Idaho, we received approval of our electric and natural gas general rate requests, with rate changes effective Jan. 1, 2018 and Jan. 1, 2019. The utility commission approved a two-year rate plan, and Avista will not file new general rate cases for rates to be effective before Jan. 1, 2020.

In Oregon, we received approval of our natural gas general rate request, and new rates went into effect on Oct. 1 and Nov. 1, 2017.

ALASKA ELECTRIC LIGHT AND POWER COMPANY

Operations at our Juneau, Alaska subsidiary, Alaska Electric Light and Power Company (AEL&P), went smoothly this year. AEL&P operations contributed $0.14 per diluted share to Avista Corp.'s earnings and made $6.4 million in capital expenditures. They plan to invest $7.0 million in capital projects in 2018.

In November 2017, the Regulatory Commission of Alaska made the 2016 interim rate increase of 3.86 percent permanent.

NON-REGULATED OPERATIONS

Non-regulated operations focused on strategic investments to help position the company for future growth. We continue to explore pathways for growth that will strengthen the company and the economies of the communities we serve. Through our investment in Energy Impact Partners, we are one of 16 active participants gaining greater access and insight into industry trends and technology innovations that can create opportunities to deliver new value to our customers in an increasingly digital and distributed industry. This and other venture investments are more than monetary, as they facilitate greater connection among industry innovators, create opportunities for sharing expertise and drive the development of products or services that are mutually beneficial.

In the long term, we envision our investments will result in both strategic and financial benefits that provide value for the utility and our stakeholders.

THE BEGINNING OF EVEN BETTER

As this year comes to a close, I'm filled with excitement and nostalgia. While the merger may appear to bring the end of something special, it is also the beginning of something special. Avista is well-positioned for what's to come, with a tenacious commitment to our customers. This, combined with our fundamental belief that every individual has an impact on our community, will carry us into the next evolution of Avista.

Scott L. Morris

Scott L. Morris
Chairman and Chief Executive Officer

ENERGY TO SERVE

We meet the energy needs of our customers through a mix of resources that provide reliable service during the coldest January night or the hottest July afternoon.

Intentional planning — focused on maximizing a diverse portfolio of resources that is predominantly renewable hydropower — positions us well to continue to meet these needs for decades to come. It's critical that we balance the needs and expectations of all our stakeholders with factors such as cost, the environment and reliability. This drives our planning, decision-making and work every year.

Our electric Integrated Resource Plan (IRP) was filed in 2017, which shows a reduction in carbon emissions from the previous IRP of about 30 percent. With this, we continue to be ranked among the lowest of the top 100 power producers for rates of carbon dioxide emissions in the country. We continue to make important capital investments in our infrastructure, all to meet three key objectives:

1 Provide safe, reliable service
2 Achieve high customer satisfaction
3 Maintain a reasonable cost to customers

CONNECTING CUSTOMERS

Avista serves a diverse customer base of over 382,000 electric and 347,000 natural gas customers across 30,000 square miles. Utility efforts focus on providing safe, reliable service and a seamless and satisfying customer experience, at a reasonable cost.

Customer expectations continue to evolve. We listen to our customers and watch trends. Today's customers want:

- To feel empowered when making energy decisions.
- To know Avista cares and has their best interests in mind.
- An easy and convenient experience.

CUSTOMER SERVICE

We are committed to providing outstanding customer service. This has resulted in satisfaction rates of over 90 percent for nearly 20 years in a row. We continue building on this, and are implementing projects and initiatives that deliver value and meet customer expectations. In 2017, we:

- Launched a new, user-friendly website, MyAvista.com. The site provides relevant, easy-to-navigate information, features enhanced search functionality and requires fewer clicks.
- Launched the Avista Marketplace, available through our website, which makes it easy for customers to save money on energy-efficient products.
- Implemented a customer appreciation program that empowers employees to engage with customers personally, in unexpected ways.

INVESTING IN RELIABILITY

To meet the growing energy needs of our customers and improve reliability and efficiency, we replaced more than 40 transmission poles on Spokane's South Hill. The location of the poles — on a bluff with hiking trails and steep terrain accessed frequently by the community — presented an opportunity to approach the work in a different way, using a resource not often used in the city. Helicopters were used to install more efficient power lines and equipment, and to replace 48 wood poles (a legacy from the 1940s) with 42 taller, steel poles. The helicopters provided efficiency with the least environmental impact. Upon completion of the full two-year upgrade project, this work increased the transmission line's maximum capacity from 78 megawatts to 350 megawatts.

TECHNOLOGY AND CUSTOMER NEEDS HAVE CHANGED SIGNIFICANTLY IN THE 70 YEARS SINCE THE NINTH & CENTRAL–SUNSET TRANSMISSION LINE WAS CONSTRUCTED. HELICOPTERS WERE USED TO REPLACE A 2.75 MILE SEGMENT OF POLES AND STRING NEW TRANSMISSION LINE WIRE FROM POLE TO POLE.

EMPOWERING INNOVATION

Avista's legacy of innovation is built through the hard work, entrepreneurial spirit and customer-focused mindset of our employees.

Through this history of innovation, we've launched companies like Itron and Ecova that seized opportunities to do things better and deliver new value to customers and Avista. Looking at the opportunities ahead, as technology and new energy sources become more widely adopted, we're implementing programs that embrace change and make sense for our customers.

SOLAR SELECT

Solar Select is a program designed by Avista for certain non-residential customers that will expand the renewable generation options available. This allows us to engage with this customer segment in new ways and reinforces our commitment to renewable energy. In 2017, we selected a location and a partner to build a facility of up to 20 megawatts in the town of Lind, Washington. Once the solar array is completed, it will be the largest in the state of Washington, and Avista will purchase all the generation output to serve non-residential customers.

IN 2017, THE EVSE PROGRAM GAINED NATIONAL RECOGNITION WITH A TECHNOLOGY TRANSFER AWARD FROM THE ELECTRIC POWER RESEARCH INSTITUTE AND A GRID EDGE AWARD FROM GREENTECH MEDIA.

ELECTRIC VEHICLE SUPPLY EQUIPMENT PROGRAM

Through Avista's Electric Vehicle Supply Equipment (EVSE) program, two DC fast-chargers were installed in 2017, supporting regional travel for electric vehicle (EV) drivers in Washington. The first installation was in Rosalia, Washington, between Spokane and Pullman. This charging station serves as an important connection point for EV transportation on this corridor in eastern Washington. The second installation was in the more urban Kendall Yards neighborhood of Spokane. On the edge of downtown, this charging station provides opportunity for those who need access while they conduct business, run errands, shop or eat in the neighborhood. Installation of charging stations in customer homes and other workplace and public locations continues. We've also received approval to extend and expand the program into 2019.

AEL&P EV PROGRAM

Driving an EV in Juneau, Alaska is appealing to many residents. EV adoption has been increasing over the last several years, and in 2017 alone, the number of EVs in Juneau nearly doubled. In 2010, AEL&P began its first EV rate program, and as EV interest and demand has increased, the rate program has changed to meet the needs of customers. To make EV charging more accessible, AEL&P offers an easy-to-use customer program and rate structure where customers can rent a charging station from AEL&P. This approach provides choices for customers, and the EV rate allows customers to charge their vehicle during off-peak hours at a reduced rate, with 100% renewable hydropower. It also benefits customers and the utility by allowing AEL&P to integrate vehicles into the system in a responsible way and with predictability in charging behavior.

STRENGTHENING COMMUNITIES

Our purpose goes beyond providing the energy that powers the daily lives of our customers. We're here to improve the quality of life and to enhance the strength, health and vitality of the communities we serve, and the communities we call home.

We're active participants in our communities and leaders who contribute through civic engagement, philanthropy and volunteer opportunities. We view Avista as a cornerstone in the communities we serve. The Avista Foundation, a community investment program of Avista Corp., provides funding to non-profit organizations addressing the needs of communities and citizens in the Avista Utilities and AEL&P service areas.

Since its creation in 2002, the foundation has given nearly $5.8 million to help feed families, educate students, improve literacy, enhance culture and strengthen our communities. In 2017, Avista's total community investment included more than $2.5 million in charitable donations and over 48,500 volunteer hours from our employees.

We create true value through partnerships. With a project called Catalyst, we're reimagining the way a specific, previously under-utilized, piece of land can serve our city, and, through intentional growth and development, how it might serve the world.

We're working with our neighbors and communities to create a healthier future for all of us, and are collaborating to connect the University District to what we envision will be the smartest blocks in the world. A gateway bridge being built by the City of Spokane will create a pathway from the University District where people, ideas, research, education and business are linked in unique ways. We're leading the development of this land to drive something bigger — to create space for growth and innovation that will drive business and enhance the economic vitality of our region.

AVISTA VOLUNTEERS WORK WITH COMMUNITY VOLUNTEER KATIE JONES TO CULTIVATE A COMMUNITY GARDEN IN A NEIGHBORHOOD NEAR AVISTA'S HEADQUARTERS.

BOARD OF DIRECTORS

ERIK J. ANDERSON, 59
CEO, Westriver Group
Kirkland, Washington
Director since 2000

KRISTIANNE BLAKE, 64
President, Kristianne Gates Blake, P.S.
Spokane, Washington
Director since 2000

DONALD C. BURKE, 57
Donald C. Burke, CPA
Langhorne, Pennsylvania
Director since 2011

REBECCA A. KLEIN, 52
Principal, Klein Energy, LLC
Austin, Texas
Director since 2010

SCOTT H. MAW, 50
Executive VP & CFO, Starbucks Coffee Co.
Seattle, Washington
Director since 2016

SCOTT L. MORRIS, 60
Chairman of the Board & CEO, Avista Corp.
Spokane, Washington
Director since 2007

MARC F. RACICOT, 69
Bigfork, Montana
Director since 2009

HEIDI B. STANLEY, 61
Co-owner & Chair, Empire Bolt & Screw Inc.
Spokane, Washington
Director since 2006

R. JOHN TAYLOR, 68
Chairman & CEO, Green Leaf Alliance
Lewiston, Idaho
Director since 1985

DENNIS P. VERMILLION, 56
President, Avista Corp.
Spokane, Washington
Director since 2018

JANET D. WIDMANN, 51
President & CEO, Kids Care Dental
San Francisco, California
Director since 2014

BOARD COMMITTEES

CORPORATE GOVERNANCE/ NOMINATING COMMITTEE
Kristianne Blake — Chair
Donald C. Burke
R. John Taylor
Janet D. Widmann

EXECUTIVE COMMITTEE
Kristianne Blake
Scott L. Morris — Chair
Heidi B. Stanley
R. John Taylor

AUDIT COMMITTEE
Kristianne Blake
Donald C. Burke (Financial Expert) — Chair
Heidi B. Stanley

COMPENSATION & ORGANIZATION COMMITTEE
Rebecca A. Klein
Scott H. Maw
R. John Taylor — Chair

FINANCE COMMITTEE
Erik J. Anderson — Chair
Scott H. Maw
Marc F. Racicot
Janet D. Widmann

ENVIRONMENTAL, TECHNOLOGY & OPERATIONS COMMITTEE
Erik J. Anderson
Rebecca A. Klein — Chair
Marc F. Racicot
Heidi B. Stanley

CORPORATE & BUSINESS UNIT OFFICERS

SCOTT L. MORRIS, 60
Chairman of the Board & CEO

DENNIS P. VERMILLION, 56
President & Environmental Compliance Officer, Board Member

MARK T. THIES, 54
Senior Vice President, CFO & Treasurer

MARIAN M. DURKIN, 64
Senior Vice President, General Counsel, Corporate Secretary & Chief Compliance Officer

KAREN S. FELTES, 62
Senior Vice President & Chief HR Officer

JASON R. THACKSTON, 48
Senior Vice President, Energy Resources

KEVIN J. CHRISTIE, 50
Vice President, External Affairs & Chief Customer Officer

BRYAN A. COX, 48
Vice President, Safety & HR Shared Services

JAMES M. KENSOK, 59
Vice President, CIO & Chief Security Officer

RYAN L. KRASSELT, 48
Vice President, Controller & Principal Accounting Officer

DAVID J. MEYER, 64
Vice President & Chief Counsel for Regulatory & Governmental Affairs

HEATHER L. ROSENTRATER, 40
Vice President, Energy Delivery

EDWARD D. SCHLECT, JR., 57
Vice President & Chief Strategy Officer

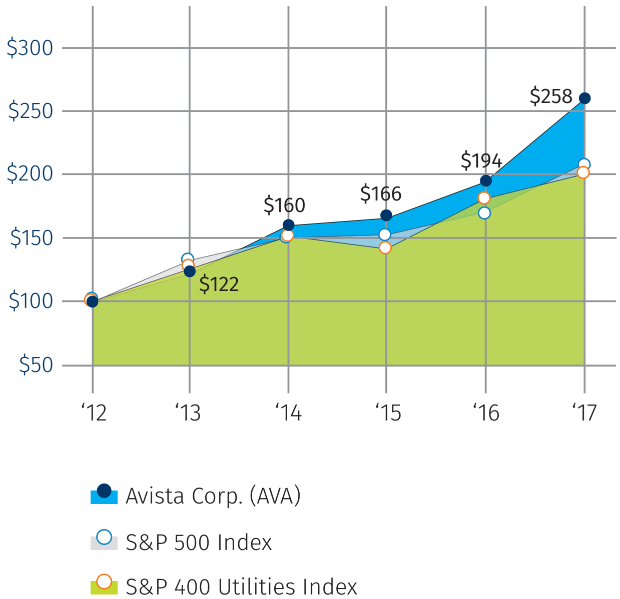
CONSTANCE S. HULBERT, 57
President, General Manager, Alaska Electric Light & Power Co.

Ages are as of the proxy date — March 30, 2018

FINANCIAL AND OPERATING HIGHLIGHTS

TOTAL SHAREHOLDER RETURN

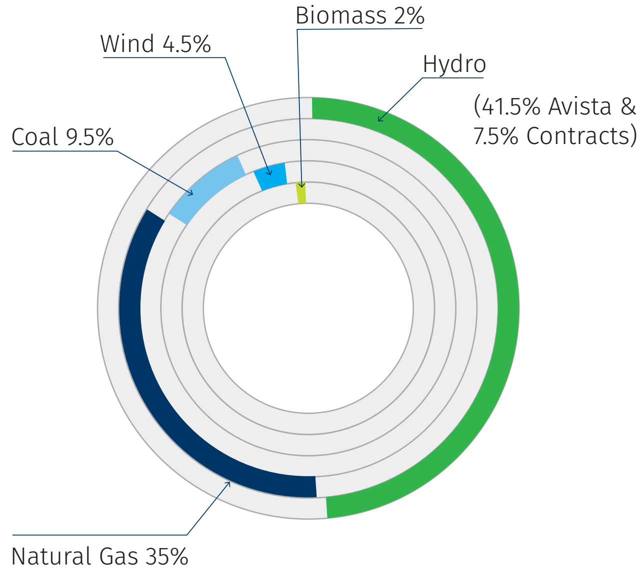
Assumes $100 was invested in Avista Corp. and each index on Dec. 31, 2012, and that all dividends were reinvested when paid.



ELECTRICITY GENERATION RESOURCE MIX

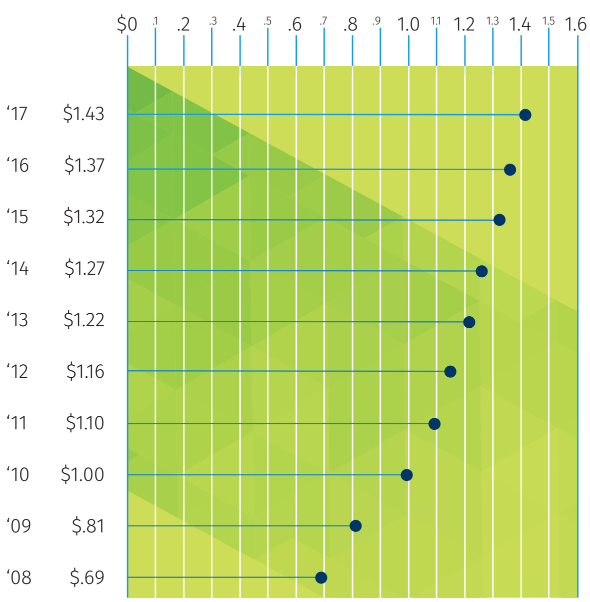
As of Dec. 31, 2017

Excludes AEL&P



COMMON STOCK DIVIDENDS PAID BY AVISTA CORP.

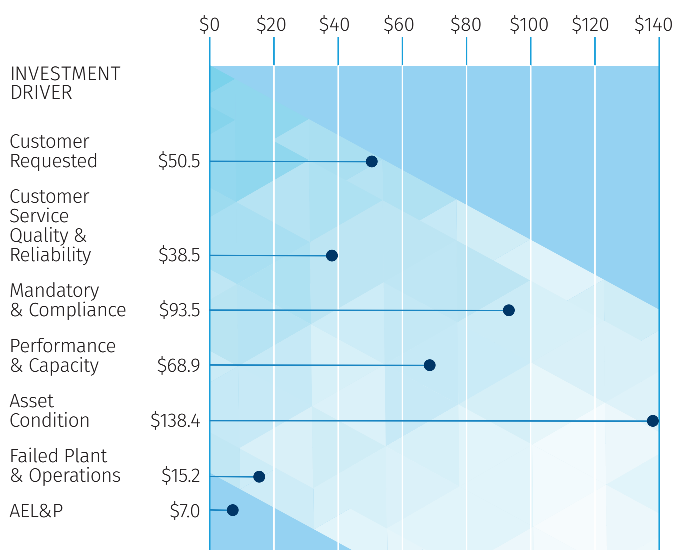
Annualized Dividend (paid in dollars)



Avista Corp.'s board of directors raised the dividend in each of the last 15 years, reflecting their confidence in the financial strength of the company.

2018 CAPITAL BUDGET

Total capital budget $412 million ($ in millions)



(dollars in thousands *except* statistics and per share amounts or as otherwise indicated)	2017	2016	2015
FINANCIAL RESULTS			
Operating revenues	$ 1,445,929	$ 1,442,483	$ 1,484,776
Operating expenses	1,161,420	1,152,680	1,231,562
Income from operations	284,509	289,803	253,214
Net income attributable to Avista Corp. shareholders	115,916	137,228	123,227
Earnings per common share attributable to Avista Corp. shareholders — diluted	1.79	2.15	1.97
Dividends paid per common share	1.43	1.37	1.32
Book value per common share	$ 26.41	$ 25.69	$ 24.53
Average common shares outstanding	64,496	63,508	62,301
Return on average Avista Corp. stockholders' equity	6.9%	8.6%	8.2%
Common stock closing price	$ 51.49	$ 39.99	$ 35.37
OPERATING RESULTS			
Avista Utilities			
Retail electric revenues	$ 811,741	$ 759,781	$ 762,809
Retail kWh sales (in millions)	8,897	8,497	8,603
Retail electric customers at year-end	382,131	377,159	374,848
Wholesale electric revenues	$ 81,512	$ 112,071	$ 127,253
Wholesale kWh sales (in millions)	2,881	2,998	3,145
Sales of fuel	$ 64,925	$ 78,334	$ 82,853
Other electric revenues	31,614	28,492	25,839
Decoupling (electric)	(8,220)	17,349	4,740
Provision for electric earnings sharing	(1,182)	932	(5,621)
Retail natural gas revenues	$ 330,073	$ 293,780	$ 297,150
Wholesale natural gas revenues	142,722	153,446	204,289
Transportation and other natural gas revenues	15,620	14,126	13,566
Decoupling (natural gas)	(11,374)	12,309	6,004
Provision for natural gas earnings sharing	(2,392)	(2,767)	—
Total therms delivered (in thousands)	1,099,141	1,173,257	1,268,431
Retail natural gas customers at year-end	347,160	340,131	334,573
Net income attributable to Avista Corp. shareholders	$ 114,716	$ 132,490	$ 113,360
Alaska Electric Light and Power Company			
Revenues	$ 53,027	$ 46,276	$ 44,778
Retail kWh sales (in millions)	414	393	398
Retail electric customers at year-end	16,951	16,798	16,672
Net income attributable to Avista Corp. shareholders	9,054	7,968	6,641
Other			
Revenues	$ 22,543	$ 23,569	$ 28,685
Net income (loss) attributable to Avista Corp. shareholders	(7,854)	(3,230)	(1,921)
FINANCIAL CONDITION			
Total assets	$ 5,514,732	$ 5,309,755	$ 4,906,649
Long-term debt and capital leases (including current portion)	1,769,237	1,682,004	1,573,278
Long-term debt to affiliated trusts	51,547	51,547	51,547
Total Avista Corp. stockholders' equity	$ 1,729,828	$ 1,648,727	$ 1,528,626

AVISTA CORP: (AVA)

FORM 10-K

FILED: FEBRUARY 20, 2018
(PERIOD: DECEMBER 31, 2017)
ANNUAL REPORT WHICH PROVIDES A
COMPREHENSIVE OVERVIEW OF THE
COMPANY FOR THE PAST YEAR.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED **DECEMBER 31, 2017** 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
website: http://www.avistacorp.com

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

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

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

Title of Class
Preferred Stock, Cumulative, Without Par Value

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

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

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

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

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

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

The aggregate market value of the Registrant's outstanding Common Stock, no par value (the only class of voting stock), held by non-affiliates is $2,734,805,418 based on the last reported sale price thereof on the consolidated tape on June 30, 2017.

As of January 31, 2018, 65,628,172 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

Documents Incorporated By Reference

Document	Part of Form 10-K into Which Document is Incorporated
Proxy Statement to be filed in connection with the annual meeting of shareholders to be held May 10, 2018. Prior to such filing, the Proxy Statement filed in connection with the annual meeting of shareholders held on May 11, 2017.	Part III, Items 10, 11, 12, 13 and 14

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ITEM NO.		PAGE NO.

PART III

* *not an applicable item in the 2017 calendar year for Avista Corp.*

ACRONYMS AND TERMS

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

Acronym/Term	Meaning
aMW	– Average Megawatt—a measure of the average rate at which a particular generating source produces energy over a period of time
AEL&P	– Alaska Electric Light and Power Company, the primary operating subsidiary of AERC, which provides electric services in Juneau, Alaska
AERC	– Alaska Energy and Resources Company, the Company's wholly owned subsidiary based in Juneau, Alaska
AFUDC	– Allowance for Funds Used During Construction; represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period
AM&D	– Advanced Manufacturing and Development, does business as METALfx
ARAM	– Average Rate Assumption Method
ASC	– Accounting Standards Codification
ASU	– Accounting Standards Update
Avista Capital	– Parent company to the Company's non-utility businesses
Avista Corp.	– Avista Corporation, the Company
Avista Energy	– Avista Energy, Inc., an inactive electricity and natural gas marketing, trading and resource management business, subsidiary of Avista Capital
Avista Utilities	– Operating division of Avista Corp. (not a subsidiary) comprising the regulated utility operations in the Pacific Northwest
BPA	– Bonneville Power Administration
Capacity	– The rate at which a particular generating source is capable of producing energy, measured in kW or MW
Cabinet Gorge	– The Cabinet Gorge Hydroelectric Generating Project, located on the Clark Fork River in Idaho
CIAC	– Contribution in aid of construction
Colstrip	– The coal-fired Colstrip Generating Plant in southeastern Montana
Coyote Springs 2	– The natural gas-fired combined-cycle Coyote Springs 2 Generating Plant located near Boardman, Oregon

ACRONYMS AND TERMS (CONTINUED)

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

Acronym/Term	Meaning
CT	– Combustion turbine
Deadband or ERM deadband	– The first $4.0 million in annual power supply costs above or below the amount included in base retail rates in Washington under the ERM in the state of Washington
Dekatherm	– Unit of measurement for natural gas; a dekatherm is equal to approximately one thousand cubic feet (volume) or 1,000,000 BTUs (energy)
Ecology	– The state of Washington's Department of Ecology
Ecova	– Ecova, Inc., a subsidiary of Avista Capital until June 30, 2014 when it was sold
EIM	– Energy Imbalance Market
Energy	– The amount of electricity produced or consumed over a period of time, measured in kWh or MWh Also, refers to natural gas consumed and is measured in dekatherms
EPA	– Environmental Protection Agency
ERM	– The Energy Recovery Mechanism, a mechanism for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Washington
FASB	– Financial Accounting Standards Board
FCA	– Fixed Cost Adjustment, the electric and natural gas decoupling mechanism in Idaho
FERC	– Federal Energy Regulatory Commission
GAAP	– Generally Accepted Accounting Principles
GHG	– Greenhouse gas
GS	– Generating station
Hydro One	– Hydro One Limited, based in Toronto, Ontario, Canada
IPUC	– Idaho Public Utilities Commission
IRP	– Integrated Resource Plan
Jackson Prairie	– Jackson Prairie Natural Gas Storage Project, an underground natural gas storage field located near Chehalis, Washington
Juneau	– The City and Borough of Juneau, Alaska
kV	– Kilovolt (1000 volts): a measure of capacity on transmission lines
kW, kWh	– Kilowatt (1000 watts): a measure of generating output or capability. Kilowatt-hour (1000 watt hours): a measure of energy produced
Lancaster Plant	– A natural gas-fired combined cycle combustion turbine plant located in Idaho

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

Acronym/Term	Meaning
LNG	– Liquefied Natural Gas
MPSC	– Public Service Commission of the State of Montana
MW, MWh	– Megawatt: 1000 kW. Megawatt-hour: 1000 kWh
NERC	– North American Electricity Reliability Corporation
Noxon Rapids	– The Noxon Rapids Hydroelectric Generating Project, located on the Clark Fork River in Montana
OPUC	– The Public Utility Commission of Oregon
PCA	– The Power Cost Adjustment mechanism, a procedure for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Idaho
PGA	– Purchased Gas Adjustment
PPA	– Power Purchase Agreement
PUD	– Public Utility District
PURPA	– The Public Utility Regulatory Policies Act of 1978, as amended
RCA	– The Regulatory Commission of Alaska
REC	– Renewable energy credit
Salix	– Salix, Inc., a subsidiary of Avista Capital, launched in 2014 to explore markets that could be served with LNG, primarily in western North America
Spokane Energy	– Spokane Energy, LLC (dissolved in the third quarter of 2015), a special purpose limited liability company and all of its membership capital was owned by Avista Corp.
TCJA	– The "Tax Cuts and Jobs Act," signed into law on December 22, 2017
Therm	– Unit of measurement for natural gas; a therm is equal to approximately one hundred cubic feet (volume) or 100,000 BTUs (energy)
Watt	– Unit of measurement for electricity; a watt is equal to the rate of work represented by a current of one ampere under a pressure of one volt
WUTC	– Washington Utilities and Transportation Commission

FORWARD-LOOKING STATEMENTS

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

- financial performance;
- cash flows;
- capital expenditures;
- dividends;
- capital structure;
- other financial items;
- strategic goals and objectives;
- 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 Annual Report on Form 10-K), and elsewhere. Forward-looking statements are all statements except those of historical fact including, without limitation, those that are identified by the use of words that include "will," "may," "could," "should," "intends," "plans," "seeks," "anticipates," "estimates," "expects," "forecasts," "projects," "predicts," and similar expressions.

Forward-looking statements (including those made in this Annual Report on Form 10-K) are subject to a variety of risks, 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;
- deterioration in the creditworthiness of our customers;
- 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 long-term climates, both globally and within our utilities' service areas, which can affect, among other things, customer demand patterns and the volume and timing of streamflows to our hydroelectric resources;

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, commodity costs, interest rate swap derivatives 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, which could result in future resource acquisitions based on the integrated resource plans that are later deemed imprudent;

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 environmental regulations affecting our ability to utilize or resulting in the obsolescence of our power supply resources;

Operational Risk

- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, 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 electric and natural gas distribution systems or other operations and may require us to purchase replacement power;
- explosions, fires, accidents or other incidents arising from or allegedly arising from our operations that may cause wildfires, injuries to the public or property damage;
- 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 or regional 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;
- increasing health care costs and cost of health insurance provided to our employees and retirees;
- third-party construction of buildings, billboard signs, towers or other structures 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;
- adverse impacts to our Alaska operations that could result from an extended outage of its hydroelectric generating resources or their inability to deliver energy, due to their lack of interconnectivity to any other electrical grids and the extensive cost of replacement power (diesel);
- changing river regulation at hydroelectric facilities not owned by us, which could impact our hydroelectric facilities downstream;

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 costs that impede our ability to effectively implement new information technology systems or to operate and maintain current production technology;
- changes in technologies, possibly making some of the current technology we utilize obsolete or introducing new cyber security risks;
- 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;
- the potential effects of negative publicity regarding our business practices, whether true or not, which could hurt our reputation and 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;
- non-regulated activities may increase earnings volatility;
- failure to complete the proposed acquisition of the Company by Hydro One, which would negatively impact the market price of Avista Corp.'s common stock and could result in termination fees that would have a material adverse effect on our results of operations, financial condition, and cash flows;

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 initiatives, 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;
- the new federal income tax law and its intended and unintended consequences on financial results and future cash flows, including the potential impact to credit ratings, which may affect our ability to borrow funds or increase the cost of borrowing in the future;
- policy and/or legislative changes resulting from the current presidential administration in various regulated areas, including, but not limited to, environmental regulation and healthcare regulations; 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 on our website as soon as practicable after electronically filing these reports with the U.S. Securities and Exchange Commission (SEC). Information contained on our website is not part of this report.

PART I

Item 1. Business

COMPANY OVERVIEW

Avista Corp., incorporated in the territory of Washington in 1889, is primarily an electric and natural gas utility with certain other business ventures. As of December 31, 2017, we employed 1,744 people in our Pacific Northwest utility operations (Avista Utilities) and 204 people in our subsidiary businesses (including our Juneau, Alaska utility operations). Our corporate headquarters are in Spokane, Washington, the second-largest city in Washington. Spokane serves as the business, transportation, medical, industrial and cultural hub of the Inland Northwest region (eastern Washington and northern Idaho). Regional services include government and higher education, medical services, retail trade and finance. Through our subsidiary AEL&P, we also provide electric utility services in Juneau, Alaska.

As of December 31, 2017, we have two reportable business segments as follows:

- **Avista Utilities**—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. Avista Utilities also engages in wholesale purchases and sales of electricity and natural gas as an integral part of energy resource management and its load-serving obligation.
- **AEL&P**—a utility providing electric services in Juneau, Alaska that is a wholly owned subsidiary and the primary operating subsidiary of AERC.

We have other businesses, including sheet metal fabrication, venture fund investments, real estate investments, as well as certain other investments of Avista Capital, which is a direct, wholly owned subsidiary of Avista Corp. These activities do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp.

Total Avista Corp. shareholders' equity was $1,729.8 million as of December 31, 2017, of which $52.6 million represented our investment in Avista Capital and $108.6 million represented our investment in AERC.

See "Item 6. Selected Financial Data" and "Note 21 of the Notes to Consolidated Financial Statements" for information with respect to the operating performance of each business segment (and other subsidiaries).

AVISTA UTILITIES

General

At the end of 2017, Avista Utilities supplied retail electric service to approximately 382,000 customers and retail natural gas service to approximately 347,000 customers across its service territory. Avista Utilities' service territory covers 30,000 square miles with a population of 1.6 million. See "Item 2. Properties" for further information on our utility assets. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Economic Conditions and Utility Load Growth" for information on economic conditions in our service territory.

Electric Operations

General—Avista Utilities generates, transmits and distributes electricity, serving electric customers in eastern Washington, northern Idaho and a small number of customers in Montana.

Avista Utilities generates electricity from facilities that we own and purchases capacity, energy and fuel for generation under long-term and short-term contracts to meet customer load obligations. We also sell electric capacity and energy, as well as surplus fuel in the wholesale market in connection with our resource optimization activities as described below.

As part of Avista Utilities' resource procurement and management operations in the electric business, we engage in an ongoing process of resource optimization, which involves the economic selection of energy resources from those available to serve our load obligations and the capture of additional economic value through wholesale market transactions. These transactions include sales and purchases of electric capacity and energy, fuel for electric generation, and derivative instruments related to capacity, energy, fuel and fuel transportation. Such transactions are part of the process of matching available resources with load obligations and hedging the related financial risks. In order to implement this process, we make continuing projections of:

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

On the basis of these projections, we make purchases and sales of electric capacity and energy, fuel for electric generation, and related derivative instruments to match expected resources to expected electric load requirements and reduce our exposure to electricity (or fuel) market price changes. The process of resource optimization involves scheduling and dispatching available resources as well as the following:

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

This optimization process includes entering into hedging transactions to manage risks. Transactions include both physical energy contracts and related derivative instruments, and the terms range from intra-hour up to multiple years.

Avista Utilities' generation assets are interconnected through the regional transmission system and are operated on a coordinated basis to enhance load-serving capability and reliability. We acquire both long-term and short-term transmission capacity to facilitate all of our energy and capacity transactions. We provide transmission and ancillary services in eastern Washington, northern Idaho and western Montana.

Electric Requirements

Avista Utilities' peak electric native load requirement for 2017 was 1,681 MW, which occurred on January 5, 2017. In 2016, our peak electric native load was 1,655 MW, which occurred during the winter, and in 2015, it was 1,638 MW, which occurred during the summer.

Electric Resources

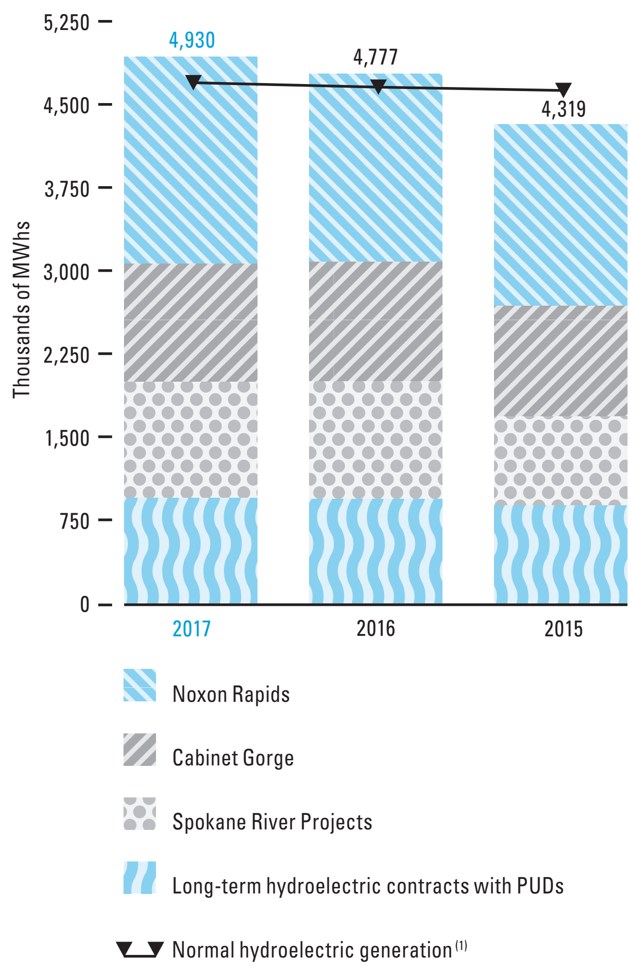
Avista Utilities has a diverse electric resource mix of Company-owned and contracted hydroelectric, thermal and wind generation facilities, and other contracts for power purchases and exchanges.

At the end of 2017, our Company-owned facilities had a total net capability of 1,875 MW, of which 56 percent was hydroelectric and 44 percent was thermal. See "Item 2. Properties" for detailed information on generating facilities.

Hydroelectric Resources—Avista Utilities owns and operates six hydroelectric projects on the Spokane River and two hydroelectric projects on the Clark Fork River. Hydroelectric generation is typically our lowest cost source per MWh of electric energy and the availability of hydroelectric generation has a significant effect on total power supply costs. Under normal streamflow and operating conditions, we estimate that we would be able to meet approximately one-half of our total average electric requirements (both retail and long-term wholesale) with the combination of our hydroelectric generation and long-term hydroelectric purchase contracts with certain PUDs in the state of Washington. Our estimate of normal annual hydroelectric generation for 2018 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 547 aMW (or 4.8 million MWhs).

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

HYDROELECTRIC GENERATION



(1) *Normal hydroelectric generation is determined by reference to the effect of upstream dam regulation on median natural water flow. Natural water flow is the flow of the rivers without the influence of dams, whereas regulated water flow takes into account any water flow changes from upstream dams due to releasing or holding back water. The calculation of normal varies annually due to the timing of upstream dam regulation throughout the year.*

Thermal Resources—Avista Utilities owns the following thermal generating resources:

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

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

Colstrip, which is operated by Talen Montana, is supplied with fuel from adjacent coal reserves under coal supply and transportation agreements in effect through 2029. In addition, see "Item 7. Management's Discussion and Analysis, Environmental Issues and Contingencies" for further discussion regarding environmental issues surrounding Colstrip.

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

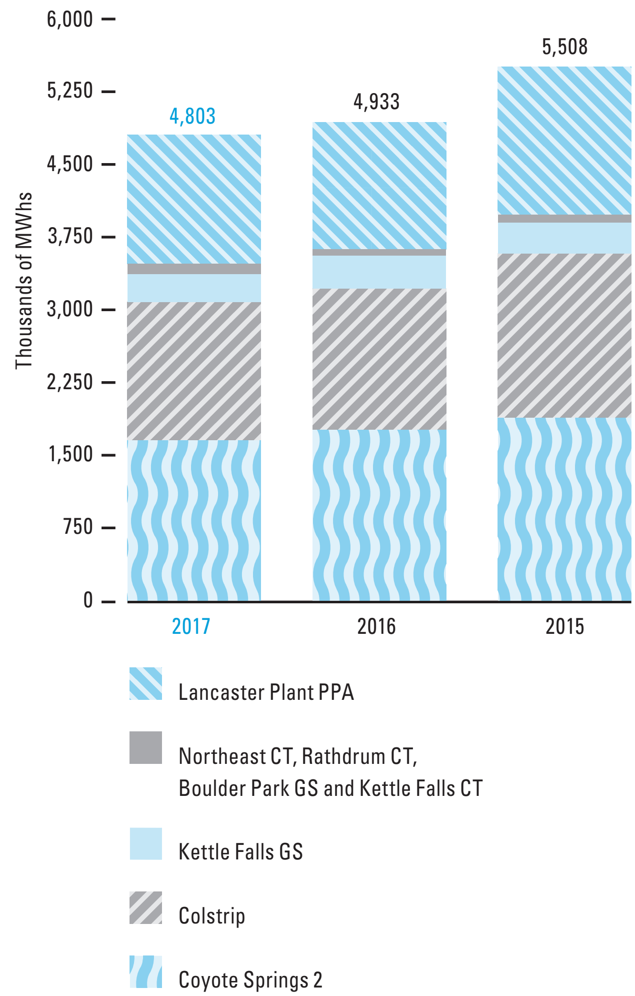
The Northeast CT, Rathdrum CT, Boulder Park GS and Kettle Falls CT generating units are primarily used to meet peaking electric requirements. We also operate these facilities when marginal costs are below prevailing wholesale electric prices. These generating facilities have access to natural gas supplies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

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

We have the exclusive rights to all the capacity of the Lancaster Plant, a 270 MW natural gas-fired combined cycle combustion turbine plant located in northern Idaho, owned by an unrelated third-party. All of the output from the Lancaster Plant is contracted to us through 2026 under a PPA. Under the terms of the PPA, we make the dispatch decisions, provide all natural gas fuel and receive all of the electric energy output from the Lancaster Plant; therefore, we consider this plant in our baseload resources. See "Note 3 of the Notes to Consolidated Financial Statements" for further discussion of this PPA.

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

THERMAL GENERATION



Wind Resources—We have exclusive rights to all the capacity of Palouse Wind, a wind generation project developed, owned and managed by an unrelated third-party and located in Whitman County, Washington. We have a PPA that expires in 2042 that requires us to acquire all of the power and renewable attributes produced by the project at a fixed price per MWh with a fixed escalation of the price over the term of the agreement. The project has a nameplate capacity of 105 MW. Generation from Palouse Wind was 300,380 MWhs in 2017, 349,771 MWhs in 2016 and 293,563 MWhs in 2015. We have an annual option to purchase the wind project beginning in December 2022. The purchase price is a fixed price per KW of in-service capacity with a fixed decline in the price per KW over the remaining 20-year term of the PPA. Under the terms of the PPA, we do not have any input into the day-to-day operation of the project, including maintenance decisions. All such rights are held by the owner.

Other Purchases, Exchanges and Sales—In addition to the resources described above, we purchase and sell power under various long-term contracts, and we also enter into short-term purchases and sales. Further, pursuant to PURPA, as amended, we are required to purchase generation from qualifying facilities. This includes, among other resources, hydroelectric projects, cogeneration projects and wind generation projects at rates approved by the WUTC and the IPUC.

See "Avista Utilities Electric Operating Statistics—Electric Operations" for annual quantities of purchased power, wholesale power sales and power from exchanges in 2017, 2016 and 2015. See "Electric Operations" above for additional information with respect to the use of wholesale purchases and sales as part of our resource optimization process and also see "Future Resource Needs" below for the magnitude of these power purchase and sales contracts in future periods.

Hydroelectric Licenses

Avista Corp. is a licensee under the Federal Power Act (FPA) as administered by the FERC, which includes regulation of hydroelectric generation resources. Excluding the Little Falls Hydroelectric Generating Project (Little Falls), our other seven hydroelectric plants are regulated by the FERC through two project licenses. The licensed projects are subject to the provisions of Part I of the FPA. These provisions include payment for headwater benefits, condemnation of licensed projects upon payment of just compensation, and take-over by the federal government of such projects after the expiration of the license upon payment of the lesser of "net investment" or "fair value" of the project, in either case, plus severance damages. In the unlikely event that a take-over occurs, it could lead to either the decommissioning of the hydroelectric project or offering the project to another party (likely through sale and transfer of the license).

Cabinet Gorge and Noxon Rapids are under one 45-year FERC license issued in 2001. See "Cabinet Gorge Total Dissolved Gas Abatement Plan" in "Note 19 of the Notes to Consolidated Financial Statements" for discussion of dissolved atmospheric gas levels that exceed state of Idaho and federal numeric water quality standards downstream of Cabinet Gorge during periods when we must divert excess river flows over the spillway, as well as our mitigation plans and efforts.

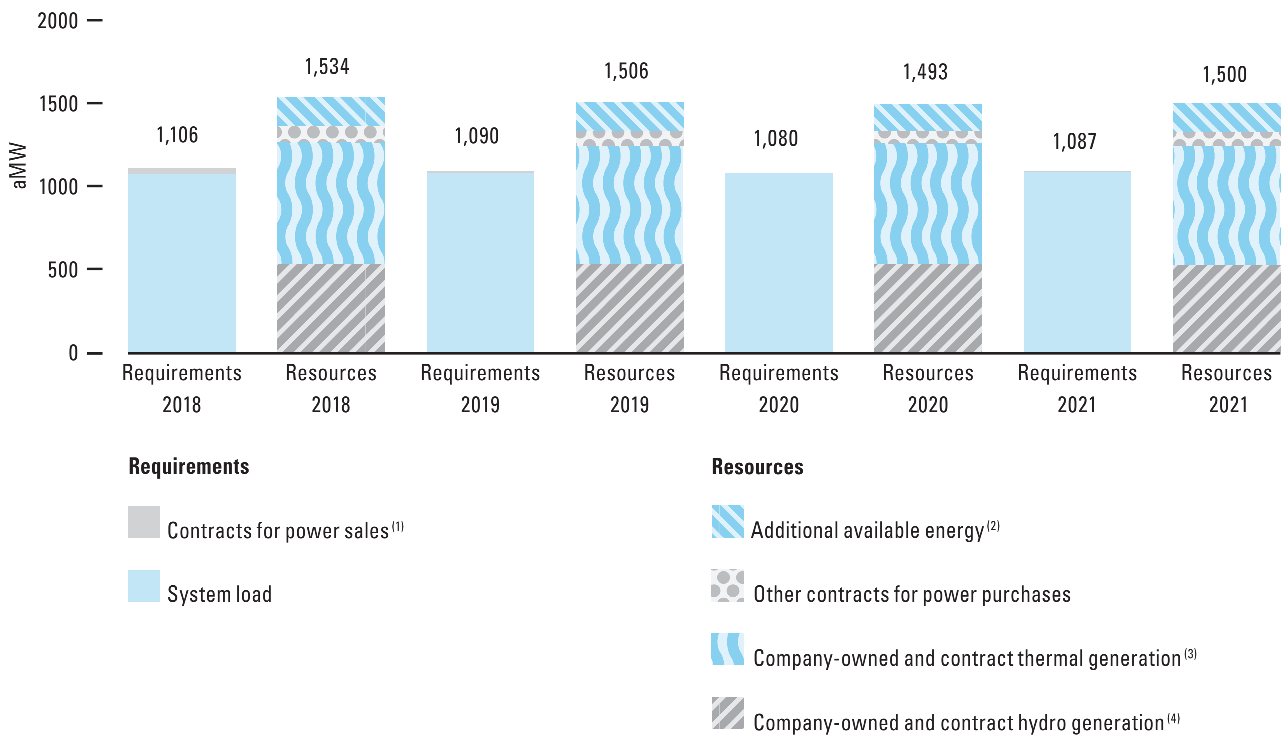
Five of our six hydroelectric projects on the Spokane River (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls) are under one 50-year FERC license issued in 2009 and are referred to collectively as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC.

Future Resource Needs

Avista Utilities has operational strategies to provide sufficient resources to meet our energy requirements under a range of operating conditions. These operational strategies consider the amount of energy needed, which varies widely because of the factors that influence demand over intra-hour, hourly, daily, monthly and annual durations. Our average hourly load was 1,070 aMW in 2017, 1,033 aMW in 2016 and 1,047 aMW in 2015.

The following graph shows our forecast of our average annual energy requirements and our available resources for 2018 through 2021:

FORECASTED ELECTRIC ENERGY REQUIREMENTS AND RESOURCES



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

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

(3) *Includes the Lancaster Plant PPA. Excludes Boulder Park GS, Kettle Falls CT, Northeast CT and Rathdrum CT, as these are considered peaking facilities and are generally not used to meet our base load requirements.*

(4) *The forecast assumes near normal hydroelectric generation.*

In August 2017, we filed our 2017 Electric IRP with the WUTC and the IPUC. The WUTC and IPUC review the IRPs and give the public the opportunity to comment. The WUTC and IPUC do not approve or disapprove of the content in the IRPs; rather they acknowledge that the IRPs were prepared in accordance with applicable standards if that is the case. The IRP details projected growth in demand for energy and the new resources needed to serve customers over the next 20 years. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project.

Highlights of the 2017 IRP include the following expectations and/or assumptions:

- Our current generation resources will remain cost effective and reliable sources of power to meet future customer needs over the next 20 years.
- Energy storage costs are significantly lower than those assumed in the 2015 IRP, which, for the first time, makes the energy storage technology operationally attractive in meeting energy needs in the 20-year timeframe of the 2017 IRP.
- A power purchase agreement for a solar facility of at least 15 MW for our new Solar Select Program for commercial and industrial customers.
- Conservation will effectively provide 53 percent of the requirements of future load growth.
- Colstrip will remain a cost effective and reliable source of power to meet future customer needs.
- If Colstrip were retired in 2030, total customer bills would increase approximately $50.0 million in the first year following retirement.

Major changes from the 2015 IRP include the following expectations and/or assumptions:

- The 2017 Expected Case energy forecast will grow at 0.47 percent per year, replacing the 0.6 percent annual growth rate in the 2015 IRP. See "Item 7. Management Discussion and Analysis—Economic Conditions and Utility Load Growth" for further discussion regarding utility customer growth, load growth, and the general economic conditions in our service territory. The estimates of future load growth in the IRP and at "Item 7. Management Discussion and Analysis—Economic Conditions and Utility Load Growth" differ slightly due to the timing of when the two estimates were prepared and due to the time period that each estimate is focused on.
- Peak load growth will be lower than energy growth, at 0.42 percent for the winter and 0.46 percent for the summer.

- Lower expected load growth combined with recent Mid-Columbia hydroelectric contracts, energy efficiency, and demand response will delay the need for additional resources from the end of 2020 until 2026.
- Demand response (temporarily reducing the demand for energy) is a viable strategy for meeting future energy needs and energy storage and solar have been added as future resources.
- We expect lower emissions from Avista Corp. owned and controlled resources due to lower utilization of natural-gas fired peaking plants and no new combined-cycle plants.

We are required to file an electric IRP every two years, with the next IRP expected to be filed during the third quarter of 2019. Our resource strategy may change from the 2017 IRP based on market, legislative and regulatory developments.

We are subject to the Washington state Energy Independence Act, which requires us to obtain a portion of our electricity from qualifying renewable resources or through purchase of RECs and acquiring all cost effective conservation measures. Future generation resource decisions will be affected by legislation for restrictions on greenhouse gas emissions and renewable energy requirements.

While not specifically addressed in the IRP, regionally, there are potential regulatory or legislative initiatives that could introduce carbon pricing or cap-and-trade mechanisms related to greenhouse gas emissions. If any of these initiatives are implemented, they could change the economics associated with operating Colstrip 3 & 4 such that the units are no longer cost effective for future customer needs. We cannot currently determine the likelihood or impact of those initiatives, but we believe if Colstrip 3 & 4 are no longer cost effective, it is reasonable to expect that there would be a regulatory process to address any undepreciated assets associated with Colstrip 3 & 4, as well as the costs associated with replacement generation and any other unforeseen closure costs that might be incurred.

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

Natural Gas Operations

General—Avista Utilities provides natural gas distribution services to retail customers in parts of eastern Washington, northern Idaho, and northeastern and southwestern Oregon.

Market prices for natural gas, like other commodities, can be volatile. Our natural gas procurement strategy is to provide a reliable supply to our customers with some level of price certainty. We procure natural gas from various supply basins and over varying time periods. The resulting portfolio is a diversified mix of forward fixed price purchases, index and spot market purchases, utilizing physical and financial derivative instruments. We also use natural gas storage to support high demand periods and to procure natural gas when prices may be lower. Securing prices throughout the year and even into subsequent years provides a level of price certainty and can mitigate price volatility to customers between years.

Weather is a key component of our natural gas customer load. This load is highly variable and daily natural gas loads can differ significantly from the monthly forecasted load projections. We make continuing projections of our natural gas loads and assess available natural gas resources. On the basis of these projections, we plan and execute a series of transactions to hedge a portion of our customers' projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend for multiple years into the future. We also leave a portion of our natural gas supply requirements unhedged for purchase in the short-term spot markets.

Our purchase of natural gas supply is governed by our procurement plan and is reviewed and approved annually by the Risk Management Committee (RMC), which is comprised of certain officers and other management personnel. Once approval is received, the plan is implemented and monitored by our gas supply and risk management groups.

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

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

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

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

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

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

Natural Gas Storage—Avista Utilities owns a one-third interest in Jackson Prairie, an underground aquifer natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 12 million therms, with a total working natural gas capacity of 256 million therms. As an owner, our share is one-third of the peak day deliverability and total working capacity. We also contract for additional storage capacity and delivery at Jackson Prairie from Northwest Pipeline for a portion of their one-third share of the storage project.

We optimize our natural gas storage capacity throughout the year by executing transactions that capture favorable market price spreads. Natural gas buyers identify opportunities to purchase lower cost natural gas in the immediate term to inject into storage, and then sell the gas in a forward market to be withdrawn at a later time. The reverse of this type of transaction also occurs. These transactions lock in incremental value for customers. Jackson Prairie is also used as a variable peaking resource, and to protect from extreme daily price volatility during cold weather or other events affecting the market.

Future Resource Needs—In August 2016, we filed our 2016 Natural Gas IRP with the WUTC, IPUC and the OPUC. The natural gas IRPs are similar in nature to the electric IRPs and the process for preparation and review by the state commissions of both the electric and natural gas IRPs is similar. The IRP details projected growth in demand for energy and the new resources needed to serve customers over the next 20 years. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project.

Highlights of the 2016 natural gas IRP include the following expectations and/or assumptions:

- We will have sufficient natural gas transportation resources well into the future with resource needs not occurring during the 20-year planning horizon in Washington, Idaho, or Oregon.
- Natural gas commodity prices will continue to be relatively stable due to robust North American supplies led by shale gas development.
- Future customer growth in our service territory will increase slightly compared to the 2014 IRP. There will be increasing interest from customers to utilize natural gas due to its abundant supply and subsequent low cost. We anticipate that any increased demand in the region will primarily come from power generation as natural gas is increasingly being used to back up solar and wind technology, as well as replace retired coal plants. There is also potential for increased usage in other markets, such as transportation and as an industrial feedstock.
- The availability of natural gas in North America will continue to change global LNG dynamics. Existing and new LNG facilities will look to export low cost North American natural gas to the higher priced Asian and European markets. This could alter the price of natural gas and/or transportation, constrain existing pipeline networks, stimulate development of new pipeline resources, and change flows of natural gas across North America.

Since forecasted demand is relatively flat, we will monitor actual demand for signs of increased growth which could accelerate resource needs.

We are required to file a natural gas IRP every two years, with the next IRP expected to be filed during the third quarter of 2018. Our resource strategy in our 2018 IRP may change from the 2016 IRP based on market, legislative and regulatory developments.

Regulatory Issues

General—As a public utility, Avista Corp. is subject to regulation by state utility commissions for prices, accounting, the issuance of securities and other matters. The retail electric and natural gas operations are subject to the jurisdiction of the WUTC, IPUC, OPUC and MPSC. Approval of the issuance of securities is not required from the MPSC. We are also subject to the jurisdiction of the FERC for licensing of hydroelectric generation resources, and for electric transmission services and wholesale sales.

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

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

Rates are designed to provide an opportunity for us to recover allowable operating expenses and earn a return of and a reasonable return on "rate base." Rate base is generally determined by reference to the original cost (net of accumulated depreciation) of utility plant in service, subject to various adjustments for deferred income taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation and retirement of utility plant and write-offs as authorized by the utility commissions. Our operating expenses and rate base are allocated or directly assigned to five regulatory jurisdictions: electric in Washington and Idaho, and natural gas in Washington, Idaho and Oregon. In general, requests for new retail rates are made on the basis of revenues, operating expenses and net investment for a test year that ended prior to the date of the request, subject to possible adjustments, which differ among the various jurisdictions, designed to reflect the expected revenues, operating expenses and net investment during the period new retail rates will be in effect. The retail rates approved by the state commissions in a rate proceeding may not provide sufficient revenues to provide recovery of costs and a reasonable return on investment for a number of reasons, including, but not limited to, unexpected changes in revenues, expenses and investment following the time new retail rates are requested in the rate proceeding, the denial by the commission of recovery, or timely recovery, of certain expenses or investment and the limitation by the commission of the authorized return on investment.

Our rates for wholesale electric and natural gas transmission services are based on either "cost of service" principles or market-based rates as set forth by the FERC. See "Notes 1 and 20 of the Notes to Consolidated Financial Statements" for additional information about regulation, depreciation and deferred income taxes.

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

Power Cost Deferrals—Avista Utilities defers the recognition in the income statement of certain power supply costs that vary from the level currently recovered from our retail customers as authorized by the WUTC and the IPUC. See "Item 7. Management's Discussion and Analysis—Regulatory Matters—Power Cost Deferrals and Recovery Mechanisms" and "Note 20 of the Notes to Consolidated Financial Statements" for information on power cost deferrals and recovery mechanisms in Washington and Idaho.

Purchased Gas Adjustment (PGA)—Under established regulatory practices in each state, Avista Utilities defers the recognition in the income statement of the natural gas costs that vary from the level currently recovered from our retail customers as authorized by each of our jurisdictions. See "Item 7. Management's Discussion and Analysis—Regulatory Matters—Purchased Gas Adjustments" and "Note 20 of the Notes to Consolidated Financial Statements" for information on natural gas cost deferrals and recovery mechanisms in Washington, Idaho and Oregon.

Decoupling and Earnings Sharing Mechanisms—Decoupling is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of Avista Utilities' jurisdictions, each month Avista Utilities' electric and natural gas revenues are adjusted so as to be based on the number of customers in certain customer rate classes and assumed "normal" kilowatt hour and therm sales, rather than being based on actual kilowatt hour and therm sales. The difference between revenues based on the number of customers and revenues based on actual usage is 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. In conjunction with the decoupling mechanisms, Washington includes an after-the-fact earnings test. At the end of each calendar year, earnings calculations are made for the prior calendar year and a portion of any earnings above a certain threshold are deferred and later returned to customers. Oregon also has an annual earnings review, not directly associated with the decoupling mechanism, where earnings above a certain threshold are deferred and later returned to customers. See "Item 7. Management's Discussion and Analysis—Regulatory Matters—Decoupling and Earnings Sharing Mechanisms" for further discussion of these mechanisms.

Federal Laws Related to Wholesale Competition

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

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

See "Item 7. Management's Discussion and Analysis—Competition" for further information.

Regional Transmission Planning

Beginning with FERC Order No. 888 and continuing with subsequent rulemakings and policies, the FERC has encouraged better coordination and operational consistency aimed to capture efficiencies that might otherwise be gained through the formation of a Regional Transmission Organization or an independent system operator (ISO).

Avista Utilities meets its FERC requirements to coordinate transmission planning activities with other regional entities through ColumbiaGrid. ColumbiaGrid is a Washington nonprofit membership corporation with an independent board formed to improve the operational efficiency, reliability, and planned expansion of the transmission grid in the Pacific Northwest. We became a member of ColumbiaGrid in 2006 during its formation. ColumbiaGrid is not an ISO, but fills the role of facilitating the regional transmission planning requirements of FERC Order No. 1000, and other clarifying FERC Orders, for its members. ColumbiaGrid and its members also work with other western organizations to address transmission planning, including WestConnect and the Northern Tier Transmission Group (NTTG). In 2011, we became a registered Planning Participant of the NTTG. We will continue to assess the benefits of entering into other functional agreements with ColumbiaGrid and/or participating in other forums to attain operational efficiencies and to meet FERC policy objectives.

Regional Energy Markets

The California Independent System Operator (CAISO) has an EIM in the western United States. Most investor-owned utilities in the Pacific Northwest are either participants in the CAISO EIM or plan to integrate into the market in the near future. The decision to join the CAISO EIM is based on a number of factors, including the amount of variable generating resources in the utilities' systems, the ability to manage the variable generating resources within the utilities' systems, the costs associated with joining the CAISO EIM, and the economic benefits associated with joining the CAISO EIM. We have conducted analyses with respect to joining the CAISO EIM, and we currently do not believe there is a compelling case to do so. As additional utilities join the CAISO EIM, there could be a reduction in bilateral market liquidity and opportunities for wholesale transactions in the Pacific Northwest. We will continue to monitor the CAISO EIM expansion and the associated impacts. As market fundamentals and our business needs evolve, we will weigh the advantages and disadvantages of joining the CAISO EIM or other organized energy markets in the future.

Reliability Standards

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

The FERC certified the NERC as the single Electric Reliability Organization authorized to establish and enforce reliability standards and delegate authority to regional entities for the purpose of establishing and enforcing reliability standards. The FERC approves NERC Reliability Standards, including western region standards that make up the set of legally enforceable standards for the United States bulk electric system. The first of these reliability standards became effective in 2007. From time-to-time new standards are developed or existing standards are updated, revised, consolidated or eliminated pursuant to an industry-involved process. We are required to self-certify our compliance with these standards on an annual basis and undergo regularly scheduled periodic reviews by the NERC and its regional entity, the Western Electricity Coordinating Council (WECC). Failure to comply with NERC reliability standards could result in financial penalties of up to $1 million per day per violation. We have a robust internal compliance program in place to manage compliance activities and mitigate the risk of potential noncompliance with these standards. We do not expect the costs associated with compliance with these standards to have a material impact on our financial results.

Peak Reliability is the reliability coordinator in the Western Interconnection that performs reliability coordinator functions for its funding parties, including Avista Corp. The CAISO, which is a significant Peak Reliability funding party recently submitted its notice of withdrawal from Peak Reliability, effective on September 2, 2019. We are evaluating the impact of CAISO's withdrawal on our cost of obtaining reliability coordinator services, which impact cannot be accurately determined at this time. We are also evaluating all alternatives for obtaining the required reliability coordinator services.

Vulnerability to Cyber Attack

It has been widely reported that the energy sector, particularly electric and natural gas utility companies in the United States and abroad, have become the subject of cyber-attacks with increased frequency. The Company's administrative and operating networks are targeted by hackers on a regular basis.

A successful attack on the Company's administrative networks could compromise the security and privacy of data, including operating, financial and personal information. A successful attack on the Company's operating networks could impair the operation of the Company's electric and/or natural gas utility facilities, possibly resulting in the inability to provide electric and/or natural gas service for extended periods of time.

The Company continually reinforces and updates its defensive systems and is in compliance with NERC's reliability standards. See "Reliability Standards," "Item 1A. Risk Factors—Technology Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Enterprise Risk Management—Technology Risks" for further information.

Avista Utilities Electric Operating Statistics
Years Ended December 31,

		2017	2016	2015
Electric Operations				
Operating Revenues (Dollars in Thousands):				
Residential		$ 381,682	$ 339,210	$ 335,552
Commercial		311,593	305,613	308,210
Industrial		110,982	107,296	111,770
Public street and highway lighting		7,484	7,662	7,277
Total retail		811,741	759,781	762,809
Wholesale		81,512	112,071	127,253
Sales of fuel		64,925	78,334	82,853
Other		31,614	28,492	25,839
Decoupling		(8,220)	17,349	4,740
Provision for earnings sharing		(1,182)	932	(5,621)
Total electric operating revenues		$ 980,390	$ 996,959	$ 997,873
Energy Sales (Thousands of MWhs):				
Residential		3,840	3,528	3,571
Commercial		3,222	3,183	3,197
Industrial		1,815	1,763	1,812
Public street and highway lighting		20	23	23
Total retail		8,897	8,497	8,603
Wholesale		2,881	2,998	3,145
Total electric energy sales		11,778	11,495	11,748
Energy Resources (Thousands of MWhs):				
Hydro generation (from Company facilities)		3,978	3,836	3,434
Thermal generation (from Company facilities)		3,476	3,626	3,983
Purchased power		4,809	4,597	4,899
Power exchanges		(6)	(6)	(2)
Total power resources		12,257	12,053	12,314
Energy losses and Company use		(479)	(558)	(566)
Total energy resources (net of losses)		11,778	11,495	11,748
Number of Retail Customers (Average for Period):				
Residential		334,848	330,699	327,057
Commercial		42,154	41,785	41,296
Industrial		1,328	1,342	1,353
Public street and highway lighting		569	558	529
Total electric retail customers		378,899	374,384	370,235
Residential Service Averages:				
Annual use per customer (kWh)		11,469	10,667	10,827
Revenue per kWh (in cents)		9.94	9.62	9.40
Annual revenue per customer		$ 1,139.87	$ 1,025.74	$ 1,017.21
Average Hourly Load (aMW)		1,070	1,033	1,047

Avista Utilities Electric Operating Statistics

Years Ended December 31,

	2017	2016	2015
Electric Operations (continued)			
Retail Native Load at time of system peak (MW):			
Winter	1,681	1,655	1,529
Summer	1,596	1,587	1,638
Cooling Degree Days: (1)			
Spokane, WA			
Actual	743	474	805
Historical average	529	545	545
% of average	140%	87%	148%
Heating Degree Days: (2)			
Spokane, WA			
Actual	6,783	5,790	5,614
Historical average	6,578	6,680	6,726
% of average	103%	87%	83%

(1) Cooling degree days are the measure of the warmness of weather experienced, based on the extent to which the average of high and low temperatures for a day exceeds 65 degrees Fahrenheit (annual degree days above historic indicate warmer than average temperatures). During 2017, we modified the calculation for historical average cooling degree days. We have recalculated 2016 and 2015 using the updated methodology to be consistent with 2017.

(2) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual degree days below historic indicate warmer than average temperatures). During 2017, we modified the calculation for historical average heating degree days. We have recalculated 2016 and 2015 using the updated methodology to be consistent with 2017.

Avista Utilities Natural Gas Operating Statistics

Years Ended December 31,

	2017	2016	2015
Natural Gas Operations			
Operating Revenues (Dollars in Thousands):			
Residential	$ 220,176	$ 195,275	$ 193,825
Commercial	104,240	92,978	96,751
Interruptible	1,901	2,179	2,782
Industrial	3,756	3,348	3,792
Total retail	330,073	293,780	297,150
Wholesale	142,722	153,446	204,289
Transportation	9,208	8,339	7,988
Other	6,412	5,787	5,578
Decoupling	(11,374)	12,309	6,004
Provision for earnings sharing	(2,392)	(2,767)	—
Total natural gas operating revenues	$ 474,649	$ 470,894	$ 521,009
Therms Delivered (Thousands of Therms):			
Residential	221,982	186,565	176,613
Commercial	133,343	112,686	107,894
Interruptible	5,465	5,700	4,708
Industrial	6,340	5,234	5,070
Total retail	367,130	310,185	294,285
Wholesale	545,348	684,317	809,132
Transportation	186,222	178,377	164,679
Interdepartmental and Company use	441	378	335
Total therms delivered	1,099,141	1,173,257	1,268,431
Number of Retail Customers (Average for Period):			
Residential	307,375	300,883	296,005
Commercial	35,192	34,868	34,229
Interruptible	37	37	35
Industrial	251	255	261
Total natural gas retail customers	342,855	336,043	330,530
Residential Service Averages:			
Annual use per customer (therms)	722	620	593
Revenue per therm (in dollars)	$ 0.99	$ 1.05	$ 1.10
Annual revenue per customer	$ 716.31	$ 649.01	$ 650.83
Heating Degree Days: (1)			
Spokane, WA			
Actual	6,783	5,790	5,614
Historical average	6,578	6,680	6,726
% of average	103%	87%	83%
Medford, OR			
Actual	4,254	3,637	3,534
Historical average	4,305	4,325	4,461
% of average	99%	84%	79%

(1) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual degree days below historic indicate warmer than average temperatures). During 2017, we modified the calculation for historical average heating degree days. We have recalculated 2016 and 2015 using the updated methodology to be consistent with 2017.

ALASKA ELECTRIC LIGHT AND POWER COMPANY

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

AEL&P owns and operates electric generation, transmission and distribution facilities located in Juneau. AEL&P operates five hydroelectric generation facilities with 102.7 MW of hydroelectric generation capacity as of December 31, 2017. AEL&P owns four of these generation facilities (totaling 24.5 MW of capacity) and has a PPA for the output of the Snettisham hydroelectric project (totaling 78.2 MW of capacity).

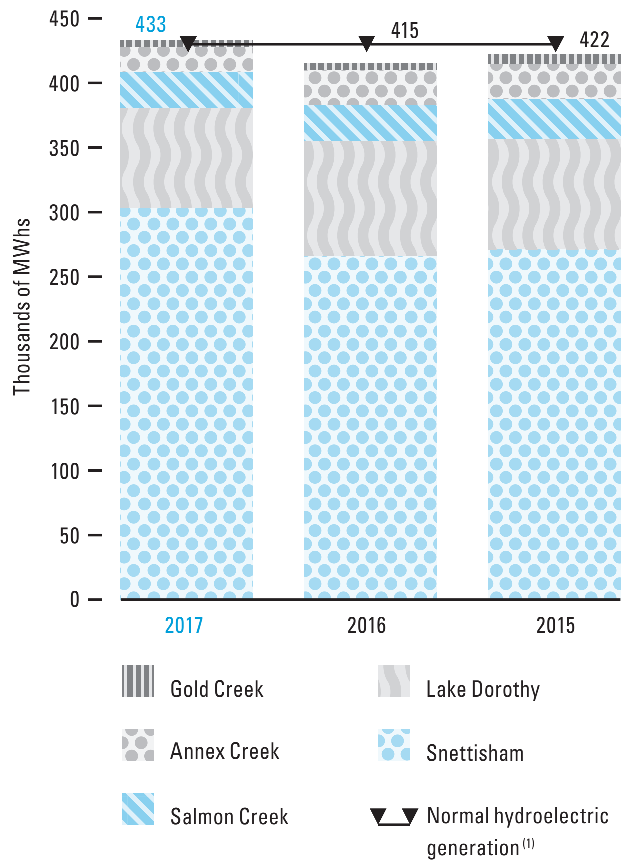
The Snettisham hydroelectric project is owned by the Alaska Industrial Development and Export Authority (AIDEA), a public corporation of the State of Alaska. AIDEA issued revenue bonds in 1998 (which were refinanced in 2015) to finance its acquisition of the project. These bonds were outstanding in the amount of $59.7 million at December 31, 2017 and mature in January 2034. AEL&P has a PPA and operating and maintenance agreement with the AIDEA to operate and maintain the facility. This PPA is a take-or-pay obligation, expiring in December 2038, to purchase all of the output of the project. AIDEA's bonds are payable solely out of the revenues received under the PPA.

For accounting purposes, this PPA is treated as a capital lease and, as of December 31, 2017, the capital lease obligation was $59.7 million. Snettisham Electric Company, a non-operating subsidiary of AERC, has the option to purchase the Snettisham project at any time for a price equal to the principal amount of the bonds outstanding at that time. See "Note 14 of the Notes to Consolidated Financial Statements" for further discussion of the Snettisham capital lease obligation.

As of December 31, 2017, AEL&P also had 107.5 MW of diesel generating capacity from four facilities to provide back-up service to firm customers when necessary.

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

HYDROELECTRIC GENERATION



(1) Normal hydroelectric generation is defined as the energy output of the plant during a year with average inflows to the reservoir.

As of December 31, 2017, AEL&P served approximately 17,000 customers. Its primary customers include city, state and federal governmental entities located in Juneau, as well as a mine located in the Juneau area. Most of AEL&P's customers are served on a firm basis while certain of its customers, including its largest customer, are served on an interruptible sales basis. AEL&P maintains separate rate tariffs for each of its customer classes, as well as seasonal rates.

AEL&P's operations are subject to regulation by the RCA with respect to rates, standard of service, facilities, accounting and certain other matters, but not with respect to the issuance of securities. Rate adjustments for AEL&P's customers require approval by the RCA pursuant to RCA regulations. See "Item 7. Management's Discussion and Analysis—Regulatory Matters" for further discussion of AEL&P's latest general rate case filing, including its capital structure.

AEL&P is also subject to the jurisdiction of the FERC concerning the permits and licenses necessary to operate certain of its hydroelectric facilities. One of these licenses (for the Salmon Creek and Annex Creek hydroelectric projects) expires in August 2018, but AEL&P is in the process of renewing and expects the renewed license to be effective in September 2018. Since AEL&P has no electric interconnection with other utilities and makes no wholesale sales, it is not subject to general FERC jurisdiction, other than the reporting and other requirements of the Public Utility Holding Company Act of 2005 as an Avista Corp. subsidiary.

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

AEL&P ELECTRIC OPERATING STATISTICS

Years Ended December 31,

	2017	2016	2015
Electric Operations			
Operating Revenues (Dollars in Thousands):			
Residential	$ 20,504	$ 18,207	$ 18,017
Commercial and government	31,726	27,322	26,049
Public street and highway lighting	279	266	215
Total retail	52,509	45,795	44,281
Other	518	481	497
Total electric operating revenues	$ 53,027	$ 46,276	$ 44,778
Energy Sales (Thousands of MWhs):			
Residential	151	139	139
Commercial and government	262	253	258
Public street and highway lighting	1	1	1
Total electric energy sales	414	393	398
Number of Retail Customers (Average for Period):			
Residential	14,575	14,448	14,285
Commercial and government	2,210	2,181	2,179
Public street and highway lighting	217	211	210
Total electric retail customers	17,002	16,840	16,674
Residential Service Averages:			
Annual use per customer (kWh)	10,360	9,621	9,730
Revenue per kWh (in cents)	13.58	13.10	12.96
Annual revenue per customer	$ 1,406.79	$ 1,260.17	$ 1,261.25
Heating Degree Days: (1)			
Juneau, AK			
Actual	8,515	7,301	7,395
Historical average	8,351	8,351	8,351
% of average	102%	87%	89%

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

OTHER BUSINESSES

The following table shows our assets related to our other businesses, including intercompany amounts as of December 31, 2017 and 2016 (dollars in thousands):

Entity and Asset Type	2017	2016
Avista Capital		
Salix—wholly owned subsidiary	$ 4,392	$ 3,842
Equity investments	2,561	3,000
Other assets	2,826	123
Avista Development		
Equity investments	19,573	11,530
Real estate	17,102	11,359
Notes receivable and other assets	6,385	5,444
METALfx—wholly owned subsidiary	11,599	11,568
Alaska companies (AERC and AJT Mining)	8,803	8,390
Total	$ 73,241	$ 55,256

Avista Capital

- Salix is a wholly owned subsidiary of Avista Capital that explores markets that could be served with LNG.
- Equity investments are primarily in an emerging technology venture capital fund.

Avista Development

- Equity investments are primarily in emerging technology venture capital funds and companies, including an investment in a technology company that delivers scalable smart grid solutions to global partners and customers, and a predictive data science company.
- Real estate consists primarily of mixed use commercial and retail office space.
- Notes receivable and other assets are primarily long-term notes receivable made to a company focused on spurring economic development throughout Washington State and to a smart grid solutions company.
- AM&D, doing business as METALfx, performs custom sheet metal fabrication of electronic enclosures, parts and systems for the computer, construction, telecom, renewable energy and medical industries. The asset balance above excludes an intercompany loan from METALfx to Avista Corp. The loan balance was $5.6 million as of December 31, 2017 and $4.0 million as of December 31, 2016.

Alaska Companies

- Includes AERC and AJT Mining, which is a wholly owned subsidiary of AERC and is an inactive mining company holding certain real estate.

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

Item 1A. Risk Factors

RISK FACTORS

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

Financial Risk Factors

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

Weather impacts are described in the following subtopics:

- certain retail electricity and natural gas sales,
- the cost of natural gas supply, and
- the cost of power supply.

Certain retail electricity and natural gas sales volumes vary directly with changes in temperatures. We normally have our highest retail (electric and natural gas) energy sales during the winter heating season in the first and fourth quarters of the year. We also have high electricity demand for air conditioning during the summer (third quarter) in the Pacific Northwest. In general, warmer weather in the heating season and cooler weather in the cooling season will reduce our customers' energy demand and our retail operating revenues. The revenue and earnings impact of weather fluctuations is somewhat mitigated by our decoupling mechanisms; however, we could experience liquidity constraints during the period between when decoupling revenue is earned and when it is subsequently collected from customers through retail rates.

The cost of natural gas supply tends to increase with higher demand during periods of cold weather. Increased costs adversely affect cash flows when we purchase natural gas for retail supply at prices above the amount then allowed for recovery in retail rates. We defer differences between actual natural gas supply costs and the amount currently recovered in retail rates and we are generally allowed to recover substantially all of these differences after regulatory review. However, these deferred costs require cash outflows from the time of natural gas purchases until the costs are later recovered through retail sales. Inter-regional natural gas pipelines and competition for supply can allow demand-driven price volatility in other regions of North America to affect prices in the Pacific Northwest, even though there may be less extreme weather conditions in the Pacific Northwest.

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

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

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

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

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

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

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

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

We rely on credit from financial institutions for short-term borrowings. We need adequate levels of credit with financial institutions for short-term liquidity. We have a $400.0 million committed line of credit that expires in April 2021. Our subsidiary AEL&P has a $25.0 million committed line of credit that expires in November 2019. There is no assurance that we will have access to credit beyond these expiration dates. The committed line of credit agreements contain customary covenants and default provisions.

Any default on the lines of credit or other financing arrangements of Avista Corp. or any of our "significant subsidiaries," if any, could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Any defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock.

We hedge a portion of our interest rate risk with financial derivative instruments, which may include interest rate swap derivatives and U.S. Treasury lock agreements. If market interest rates decrease below the interest rates we have locked in, this will result in a liability related to our interest rate swap derivatives, which can be significant. As of December 31, 2017, we had a net interest rate swap derivative liability of $66.0 million, reflecting a decline in interest rates since the time we entered into the agreements. We did not have any U.S. Treasury lock agreements outstanding as of December 31, 2017. We may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the derivative instruments. Settlement of interest rate swap derivative instruments in a liability position could require a significant amount of cash, which could negatively impact our liquidity and short-term credit availability and increase interest expense over the term of the associated debt.

In our 2017 Washington electric and natural gas general rate cases, WUTC Staff recommended the exclusion of our 2016 settled interest rate swaps from the cost of capital calculation. The total amount of the 2016 settled interest rate swaps was $54.0 million, with approximately 60 percent of this total being allocated to Washington. If recovery of the 2016 settled interest rate swap payments referenced above is not approved by the WUTC, this could change our current conclusion that settlement payments related to the 2017 settled interest rate swaps and the unsettled interest rate swaps are probable of recovery through rates. See "Item 7. Management's Discussion and Analysis—Regulatory Matters—2017 Washington General Rate Cases" for further discussion of this issue.

Downgrades in our credit ratings could impede our ability to obtain financing, adversely affect the terms of financing and impact our ability to transact for or hedge energy resources. If we do not maintain our investment grade credit rating with the major credit rating agencies, we could expect increased debt service costs, limitations on our ability to access capital markets or obtain other financing on reasonable terms, and requirements to provide collateral (in the form of cash or letters of credit) to lenders and counterparties. In addition, credit rating downgrades could reduce the number of counterparties willing to do business with us or result in the termination of outstanding regulatory authorizations for certain financing activities.

Credit risk may be affected by industry concentration and geographic concentration.

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

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

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

Utility Regulatory Risk Factors

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

Avista Utilities' annual operating expenses and the costs associated with incremental investments in utility assets continue to grow at a faster rate than revenue growth. Our ability to recover these expenses and capital costs depends on the amount and timeliness of retail rate changes allowed by regulatory agencies. We expect to periodically file for rate increases with regulatory agencies to recover our expenses and capital costs and provide an opportunity to earn a reasonable rate of return for shareholders. If regulators do not grant rate increases or grant substantially lower rate increases than our requests in the future or if recovery of deferred expenses is disallowed, it could have a negative effect on our operating revenues, net income and cash flows. Negative impacts to our financial results may result in our credit ratings being downgraded which may make it more costly for us to issue future debt securities and could increase borrowing costs under our credit facilities. See further discussion of regulatory matters in "Item 7. Management's Discussion and Analysis—Regulatory Matters."

In the future, we may no longer meet the criteria for continued application of regulatory accounting practices for all or a portion of our regulated operations.

If we could no longer apply regulatory accounting, we could be:

- required to write off our regulatory assets, and
- precluded from the future deferral of costs or decoupled revenues not recovered through rates at the time such amounts are incurred, even if we are expected to recover these amounts from customers in the future.

See further discussion at "Note 1 of the Notes to Consolidated Financial Statements—Regulatory Deferred Charges and Credits" and "Item 7. Management's Discussion and Analysis—Regulatory Matters—2017 Washington General Rate Cases."

Energy Commodity Risk Factors

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

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

- our obligation to serve our retail customers at rates set through the regulatory process—we cannot decline to serve our customers and we cannot change retail rates to reflect current energy prices unless and until we receive regulatory approval,
- customer demand, which is beyond our control because of weather, customer choices, prevailing economic conditions and other factors,
- some of our energy supply cost is fixed by the nature of the energy-producing assets or through contractual arrangements (however, a significant portion of our energy resource costs are not fixed), and
- the potential non-performance by commodity counterparties, which could lead to replacement of the scheduled energy or natural gas at higher prices.

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

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

Cash flow deferrals related to energy commodities can be significant. We are permitted to collect from customers only amounts approved by regulatory commissions. However, our costs to provide energy service can be much higher or lower than the amounts currently billed to customers. We are permitted to defer income statement recognition and recovery from customers for some of these differences, which are recorded as deferred charges with the opportunity for future recovery through retail rates. These deferred costs are subject to review for prudence and potential disallowance by regulators, who have discretion as to the extent and timing of future recovery or refund to customers.

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

Even if our regulators ultimately allow us to recover deferred power and natural gas costs, our operating cash flows can be negatively affected until these costs are recovered from customers.

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

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

Generation plants may become obsolete. We rely on a variety of generation and energy commodity market sources to fulfill our obligation to serve customers and meet the demands of our counterparty agreements. There is the potential that some of our generation sources, such as coal, may become obsolete or be prematurely retired through regulatory action. This could result in higher commodity costs to replace the lost generation, as well as higher costs to retire the generation source before the end of its expected life.

Operational Risk Factors

We are subject to various operational and event risks.

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

- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, snow and ice storms, which can disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies support services and general business operations,
- blackouts or disruptions of interconnected transmission systems (the regional power grid),
- unplanned outages at generating plants,
- fuel cost and availability, including delivery constraints,
- explosions, fires, accidents, or mechanical breakdowns that may occur while operating and maintaining our generation, transmission and distribution systems,
- damage or injuries to third parties caused by our generation, transmission and distribution systems,
- natural disasters that can disrupt energy generation, transmission and distribution, and general business operations,
- terrorist attacks or other malicious acts that may disrupt or cause damage to our utility assets or the vendors we utilize, and
- 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.

Disasters may affect the general economy, financial and capital markets, specific industries, or our ability to conduct business. As protection against operational and event risks, we maintain business continuity and disaster recovery plans, maintain insurance coverage against some, but not all, potential losses and we seek to negotiate indemnification arrangements with contractors for certain event risks. However, insurance or indemnification agreements may not be adequate to protect us against liability, extra expenses and operating disruptions from all of the operational and event risks described above. In addition, we are subject to the risk that insurers and/or other parties will dispute or be unable to perform on their obligations to us.

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

Adverse impacts may occur at our Alaska operations that could result from an extended outage of their hydroelectric generating resources or its inability to deliver energy, due to their lack of interconnectivity to any other electrical grids and the extensive cost of replacement power (diesel).

AEL&P operates several hydroelectric power generation facilities and has diesel generating capacity from multiple facilities to provide backup service to firm customers when necessary; however, a single hydroelectric power generation facility, the Snettisham hydroelectric project, provides approximately two-thirds of AEL&P's hydroelectric power generation. Any issues that negatively affect AEL&P's ability to generate or transmit power or any decrease in the demand for the power generated by AEL&P could negatively affect our results of operations, financial condition and cash flows.

Compliance Risk Factors

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

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

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

Actions or limitations to address concerns over long-term climate change, both globally and within our utilities' service areas, may affect our operations and financial performance.

Legislative, regulatory and advocacy efforts at the state, national and international levels concerning climate change and other environmental issues could have significant impacts on our operations. The electric and natural gas utility industries are frequently affected by proposals to curb greenhouse gas and other air emissions. Various regulatory and legislative proposals have been made to limit or further restrict byproducts of combustion, including that resulting from the use of natural gas by our customers. In addition, regionally, there are a number of regulatory and legislative initiatives that have been proposed which could introduce carbon pricing or cap-and-trade mechanisms related to greenhouse gas emissions, and we cannot predict whether any such proposals will be enacted. Such proposals, if adopted, could restrict the operation and raise the costs of our power generation resources as well as the distribution of natural gas to our customers.

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

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

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

In the normal course of our business, we have matters that are the subject of ongoing litigation, mediation, investigation and/or negotiation. We cannot predict the ultimate outcome or potential impact of any particular issue, including the extent, if any, of insurance coverage or that amounts payable by us may be recoverable through the ratemaking process. We are subject to environmental regulation by federal, state and local authorities related to our past, present and future operations. See "Note 19 of the Notes to Consolidated Financial Statements" for further details of these matters.

Technology Risk Factors

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

In the course of our operations, we rely on interconnected technology systems for operation of our generating plants, electric transmission and distribution systems, natural gas distribution systems, customer billing and customer service, accounting and other administrative processes and compliance with various regulations. In addition, in the ordinary course of business, we collect and retain sensitive information including personal information about our customers and employees.

There are various risks associated with technology systems such as hardware or software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other deliberate or inadvertent human errors. In particular, cyber attacks, terrorism or other malicious acts could damage, destroy or disrupt these systems. Additionally, the facilities and systems of clients, suppliers and third-party service providers could be vulnerable to these same risks and, to the extent of interconnection to our technology, may impact us. Any failure, unexpected, or unauthorized use of technology systems could result in the unavailability of such systems, and could result in a loss of operating revenues, an increase in operating expenses and costs to repair or replace damaged assets. Any of the above could also result in the loss or release of confidential customer and/or employee information or other proprietary data that could adversely affect our reputation and competitiveness, could result in costly litigation and negatively impact our results of operations. These cyber attacks have become more common and sophisticated and, as such, we could be required to incur costs to strengthen our systems and respond to emerging concerns.

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

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

We are currently planning to replace all of our electric meter infrastructure in Washington State with two-way communication advanced metering infrastructure (AMI). There is the risk that regulators will not allow the full recovery of new AMI. In addition, there are inherent risks associated with replacing and changing these types of systems, such as incorrect or nonfunctioning metering and/or delayed or inaccurate customer bills or unplanned outages, which could have a material adverse effect on our results of operations, financial condition and cash flows. Finally, there is the risk that we ultimately do not complete the project and will incur contract cancellation or other costs, which could be significant.

Strategic Risk Factors

Our strategic business plans, which may be affected by any or all of the foregoing, may change, 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.

Our strategic business plans could be affected by or result in any of the following:

- disruptive innovations in the marketplace may outpace our ability to compete or manage our risk,
- 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,

- market or other conditions may adversely affect our operations or require changes to our business strategy, which could result in a non-cash goodwill impairment charge that would reduce assets and reduce our net income, and
- potential reputational risk arising from repeated general rate case filings, degradation in the quality of service, or from failed strategic investments and opportunities, which could erode shareholder, customer and community satisfaction with our Company.

We are subject to various risks specifically related to the proposed acquisition by Hydro One.

The conditions to the acquisition may not be satisfied. The proposed acquisition by Hydro One requires approval by the holders of a majority of Avista Corp.'s outstanding shares of common stock and the receipt of regulatory approvals, including from the FERC, the Committee on Foreign Investment in the United States (CFIUS), the Federal Communications Commission (FCC), the WUTC, IPUC, MPSC, OPUC, and the RCA. Also, the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended is required. Avista Corp. shareholder and FERC approval have been obtained; however, the other regulatory approvals may not be obtained or the regulatory bodies may seek to impose conditions on the completion of the transaction, which could cause the conditions specified in the Merger Agreement to not be satisfied or which could delay or increase the cost of the transaction. In addition, the failure to satisfy other closing conditions could result in a termination of the Merger Agreement by Hydro One and/or Avista Corp.

We may be required to pay a termination fee if the acquisition is not consummated. Upon termination of the Merger Agreement under certain specified circumstances, we would be required to pay Hydro One a termination fee of $103.0 million (Company Termination Fee). We would also be required to pay Hydro One the Company Termination Fee in the event that we signed or consummated any specified alternative transaction within twelve months following the termination of the Merger Agreement under certain circumstances. Any fees due as a result of termination could have a material adverse effect on our results of operations, financial condition, and cash flows.

Failure to consummate the acquisition could negatively impact the market value of Avista Corp. common stock and our access to and cost of capital. There can be no assurance that the Merger will be consummated. Failure to consummate the Merger could (i) affect the value of Avista Corp.'s common stock, including by reducing it to a level at or below the trading range preceding the announcement of the Merger Agreement and (ii) negatively affect our access to and cost of both equity and debt financing.

Additionally, if the Merger is not consummated, we would have incurred significant costs and diverted the time and attention of management. A failure to consummate the Merger might also result in negative publicity, litigation against Avista Corp. or its directors and officers, and a negative impression of Avista Corp. in the financial markets. The occurrence of any of these events individually or in combination could have a material adverse effect on our financial condition, results of operations, cash flows and stock price.

We have been faced with legal proceedings related to the pending acquisition by Hydro One. In connection with the proposed acquisition, as of the date of this annual report, three lawsuits have been filed in the United States District Court for the Eastern District of Washington and one lawsuit has been filed in the Superior Court for the State of Washington in and for Spokane County. These lawsuits were filed against members of the Company's Board of Directors and various other parties. The three lawsuits filed in the United States District Court for the Eastern District of Washington have been voluntarily dismissed by the plaintiffs, leaving only the state lawsuit remaining.

The remaining complaint generally alleges that the members of the Board breached their fiduciary duties by, among other things, conducting an allegedly inadequate sale process and agreeing to the acquisition at a price that allegedly undervalues Avista Corp., and that Hydro One, Olympus Holding Corp., and Olympus Corp. aided and abetted those purported breaches of duty. The aiding and abetting claims were brought only against Hydro One, Olympus Holding Corp. and Olympus Corp. The complaints seek various remedies, including an injunction against the acquisition and monetary damages, including attorneys' fees and expenses. The complaint has been stayed by the court until the closing of the transaction at which time the plaintiff will have the option to file an amended complaint within 30 days of such closing. If the amended complaint is not filed within the 30 days the suit will be dismissed.

Since Avista Corp. is obligated to indemnify the defendants under its articles of incorporation, bylaws and separate agreements, the outcome of the lawsuit could, among other things, result in a material adverse effect on Avista Corp.'s financial condition, results of operations and cash flows.

External Mandates Risk Factors

External mandate risk involves forces outside the Company, which may include significant changes in customer expectations, disruptive technologies that result in obsolescence of our business model and government action that could impact our Company.

Recent U.S. tax legislation may materially adversely affect our financial condition, results of operations and cash flows and affect our credit ratings.

On December 22, 2017, the "Tax Cuts and Jobs Act" (TCJA) was signed into law. The legislation includes substantial changes to the taxation of individuals as well as U.S. businesses, multi-national enterprises, and other types of taxpayers. The most significant change as a result of the TCJA is a permanent reduction of the statutory corporate tax rate from 35 percent to 21 percent. The legislation is unclear in certain respects and will require implementing regulations by the U.S. Treasury Department, as well as interpretations by the Internal Revenue Service (IRS) and state tax authorities, and the legislation could be subject to potential amendments and technical corrections, any of which could lessen or increase certain adverse impacts of the legislation. In addition, the regulatory treatment of certain impacts of this legislation will be subject to the discretion of the FERC and state public utility commissions.

Our analysis and interpretation of this legislation is complete as it relates to amounts recorded as of December 31, 2017 and based on our evaluation, the reduction of the U.S. corporate income tax rate required a write-down of our deferred income tax assets and liabilities (including the value of our net operating loss carryforwards) during the fourth quarter of 2017, the period in which the tax legislation was enacted. Because we are predominantly a rate-regulated entity, a large portion of the net effect of the legislation has been recorded as a net regulatory liability on the Consolidated Balance Sheets that will be returned to customers through the ratemaking process in future periods.

Although it is unclear when or how capital markets, credit rating agencies, the FERC or state public utility commissions may respond to this legislation, we do expect that certain financial metrics used by credit rating agencies to evaluate the Company may be negatively impacted as a result of the TCJA. This is primarily due to our expectation that future cash flows from operations will be negatively impacted due to the loss of the bonus depreciation tax deduction and from the timing of the return of excess deferred taxes to customers. There may be other material adverse effects resulting from the legislation that we have not yet identified. Moody's has placed a negative outlook on our credit rating. We cannot predict whether Moody's will take further action in the future, or whether other credit rating agencies will take similar action. Any further action by credit rating agencies may make it more costly for us to issue future debt securities and could increase borrowing costs under our credit facilities.

We believe that interpretations and implementing regulations by the IRS, as well as potential amendments and technical corrections, could result in reducing the negative impacts of certain aspects of this legislation, although there can be no assurance that this will occur or that interpretations, regulations, amendments and technical corrections will not exacerbate some of the negative impacts of the legislation. If additional interpretations, regulations, amendments or technical corrections and/or actions by the FERC and state public utility commissions exacerbate the adverse impacts of the legislation, the legislation could have a material adverse effect on our financial condition, results of operations and cash flows.

See "Item 7. Management's Discussion and Analysis—Environmental Issues and Contingencies" and "Forward-Looking Statements" for discussion of or reference to additional external mandates which could have a material adverse effect on our results of operations, financial condition and cash flows.

Item 1B. Unresolved Staff Comments

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

Item 2. Properties

AVISTA UTILITIES

Substantially all of Avista Utilities' properties are subject to the lien of Avista Corp.'s mortgage indenture.

Avista Utilities' electric properties, located in the states of Washington, Idaho, Montana and Oregon, include the following:

GENERATION PROPERTIES

	No. of Units	Nameplate Rating (MW) [1]	Present Capability (MW) [2]
Hydroelectric Generating Stations (River)			
Washington:			
Long Lake (Spokane)	4	70.0	88.0
Little Falls (Spokane)	4	40.4	40.4
Nine Mile (Spokane)	4	37.6	37.6
Upper Falls (Spokane)	1	10.0	10.2
Monroe Street (Spokane)	1	14.8	15.0
Idaho:			
Cabinet Gorge (Clark Fork) [3]	4	265.0	273.0
Post Falls (Spokane)	6	14.8	15.4
Montana:			
Noxon Rapids (Clark Fork)	5	487.8	562.4
Total Hydroelectric		940.4	1,042.0
Thermal Generating Stations (cycle, fuel source)			
Washington:			
Kettle Falls GS (combined-cycle, wood waste) [4]	1	50.7	53.5
Kettle Falls CT (combined-cycle, natural gas) [4]	1	7.2	6.9
Northeast CT (simple-cycle, natural gas)	2	61.8	64.8
Boulder Park GS (simple-cycle, natural gas)	6	24.6	24.6
Idaho:			
Rathdrum CT (simple-cycle, natural gas)	2	166.5	166.5
Montana:			
Colstrip Units 3 & 4 (simple-cycle, coal) [5]	2	233.4	222.0
Oregon:			
Coyote Springs 2 (combined-cycle, natural gas)	1	295.0	295.0
Total Thermal		839.2	833.3
Total Generation Properties		1,779.6	1,875.3

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

(2) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions. Information is provided as of December 31, 2017.

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

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

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

Electric Distribution and Transmission Plant

Avista Utilities owns and operates approximately 19,000 miles of primary and secondary electric distribution lines providing service to retail customers. We have an electric transmission system of approximately 700 miles of 230 kV line and approximately 1,550 miles of 115 kV line. We also own an 11 percent interest in approximately 500 miles of a 500 kV line between Colstrip, Montana and Townsend, Montana. Our transmission and distribution systems also include numerous substations with transformers, switches, monitoring and metering devices, and other equipment.

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

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

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

Natural Gas Plant

Avista Utilities has natural gas distribution mains of approximately 3,400 miles in Washington, 2,000 miles in Idaho and 2,400 miles in Oregon. We have natural gas transmission mains of approximately 75 miles in Washington and 15 miles in Oregon. Our natural gas system includes numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment.

We own a one-third interest in Jackson Prairie, an underground natural gas storage field located near Chehalis, Washington. See "Part 1—Item 1. Business—Avista Utilities—Natural Gas Operations" for further discussion of Jackson Prairie.

ALASKA ELECTRIC LIGHT AND POWER COMPANY

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

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

GENERATION PROPERTIES AND TRANSMISSION AND DISTRIBUTION LINES

	No. of Units	Nameplate Rating (MW) (1)	Present Capability (MW) (2)
Hydroelectric Generating Stations			
Snettisham (3)	3	78.2	78.2
Lake Dorothy	1	14.3	14.3
Salmon Creek	1	8.4	5.0
Annex Creek	2	4.1	3.6
Gold Creek	3	1.6	1.6
Total Hydroelectric		106.6	102.7
Diesel Generating Stations			
Lemon Creek	11	61.4	51.8
Auke Bay	3	28.4	25.2
Gold Creek	5	8.2	7
Industrial Blvd. Plant	1	23.5	23.5
Total Diesel		121.5	107.5
Total Generation Properties		228.1	210.2

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

(2) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions. Information is provided as of December 31, 2017.

(3) AEL&P does not own this generating facility but has a PPA under which it has the right to purchase, and the obligation to pay for (whether or not energy is received), all of the capacity and energy of this facility. See further information at "Part 1. Item 1. Business—Alaska Electric Light and Power Company."

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

Item 3. Legal Proceedings

See "Note 19 of Notes to Consolidated Financial Statements" for information with respect to legal proceedings.

Item 4. Mine Safety Disclosures

Not applicable.

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

Avista Corp. Market Information and Dividend Policy

Avista Corp.'s common stock is listed on the New York Stock Exchange under the ticker symbol "AVA." As of January 31, 2018, there were 7,848 registered shareholders of our common stock.

Avista Corp.'s Board of Directors considers the level of dividends on our common stock on a recurring basis, taking into account numerous factors including, without limitation:

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

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

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

- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements (see "Item 7. Management's Discussion and Analysis—Capital Resources" for compliance with these covenants),
- the hydroelectric licensing requirements of section 10(d) of the FPA (see "Note 1 of Notes to Consolidated Financial Statements"),
- certain requirements under the OPUC approval of the AERC acquisition in 2014. The OPUC's AERC acquisition order requires Avista Utilities to maintain a capital structure of no less than 40 percent common equity (inclusive of short-term debt). This limitation may be revised upon request by the Company with approval from the OPUC,
- certain covenants applicable to preferred stock (when outstanding) contained in the Company's Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding), and
- the Merger Agreement with Hydro One, which states Avista Corp. cannot (A) declare, authorize, set aside for payment or pay any dividend on, or make any other distribution in respect of, any shares of its capital stock, other than (1) dividends paid by any Subsidiary of the Company to the Company or to any wholly owned subsidiary of the Company, (2) quarterly cash dividends with respect to the Company common stock not to exceed the 2017 annual per share dividend rate by more than $0.06 per year, with record dates and payment dates consistent with the Company's current dividend practice, or (3) a "stub period" dividend to holders of record of Company common stock as of immediately prior to the effective time of the merger equal to the product of (x) the number of days from the record date for payment of the last quarterly dividend paid by the Company prior to the effective time of the merger, multiplied by (y) a daily dividend rate determined by dividing the amount of the last quarterly dividend prior to the effective time of the merger by ninety-one or (B) adjust, split, combine, subdivide or reclassify any shares of its capital stock (see "Note 4 of the Notes to Consolidated Financial Statements" for additional information regarding the merger).

On February 2, 2018, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.3725 per share on the Company's common stock. This was an increase of $0.015 per share, or 4.2 percent from the previous quarterly dividend of $0.3575 per share.

For additional information, see "Notes 1, 17 and 18 of Notes to Consolidated Financial Statements."

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

	Three Months Ended			
	March 31	June 30	September 30	December 31
2017				
Dividends paid per common share	$ 0.3575	$ 0.3575	$ 0.3575	$ 0.3575
Trading price range per common share:				
High	$ 40.14	$ 44.40	$ 52.74	$ 52.35
Low	$ 37.94	$ 38.62	$ 41.35	$ 51.25
2016				
Dividends paid per common share	$ 0.3425	$ 0.3425	$ 0.3425	$ 0.3425
Trading price range per common share:				
High	$ 41.12	$ 44.80	$ 44.97	$ 42.63
Low	$ 34.67	$ 38.70	$ 40.43	$ 39.11

On July 18, 2017, the last trading day prior to the public announcement of the Merger Agreement with Hydro One, the reported last sale price for Avista Corp. common stock was $42.74 per share as reported in the consolidated reporting system. On July 20, 2017, the first trading day following the announcement of the Merger Agreement, the reported last sale price for Avista Corp. common stock was $52.28 per share as reported in the consolidated reporting system.

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

Item 6.

SELECTED FINANCIAL DATA

Avista Corporation
(in thousands, except per share data and ratios)
Years Ended December 31,

	2017	2016	2015	2014	2013
Operating Revenues:					
Avista Utilities	$ 1,370,359	$ 1,372,638	$ 1,411,863	$ 1,413,499	$ 1,403,995
AEL&P	53,027	46,276	44,778	21,644	—
Other	22,543	23,569	28,685	39,219	39,549
Intersegment eliminations	—	—	(550)	(1,800)	(1,800)
Total	$ 1,445,929	$ 1,442,483	$ 1,484,776	$ 1,472,562	$ 1,441,744
Income (Loss) from Operations (pre-tax):					
Avista Utilities	$ 270,409	$ 277,070	$ 241,228	$ 239,976	$ 232,572
AEL&P	17,947	15,434	14,072	6,221	—
Other	(3,847)	(2,701)	(2,086)	6,391	(1,483)
Total	$ 284,509	$ 289,803	$ 253,214	$ 252,588	$ 231,089
Net income from continuing operations	$ 115,932	$ 137,316	$ 118,170	$ 119,866	$ 104,333
Net income from discontinued operations	—	—	5,147	72,411	7,961
Net income	$ 115,932	$ 137,316	$ 123,317	$ 192,277	$ 112,294
Net income attributable to noncontrolling interests	$ (16)	$ (88)	$ (90)	$ (236)	$ (1,217)
Net Income (Loss) attributable to Avista Corporation shareholders:					
Avista Utilities	$ 114,716	$ 132,490	$ 113,360	$ 113,263	$ 108,598
AEL&P	9,054	7,968	6,641	3,152	—
Ecova—Discontinued operations	—	—	5,147	72,390	7,129
Other	(7,854)	(3,230)	(1,921)	3,236	(4,650)
Net income attributable to Avista Corp. shareholders	$ 115,916	$ 137,228	$ 123,227	$ 192,041	$ 111,077
Average common shares outstanding—basic	64,496	63,508	62,301	61,632	59,960
Average common shares outstanding—diluted	64,806	63,920	62,708	61,887	59,997
Common shares outstanding at year-end	65,494	64,188	62,313	62,243	60,077
Earnings per common share attributable to Avista Corp. shareholders—basic:					
Earnings per common share from continuing operations	$ 1.80	$ 2.16	$ 1.90	$ 1.94	$ 1.74
Earnings per common share from discontinued operations	—	—	0.08	1.18	0.11
Total earnings per common share attributable to Avista Corp. shareholders—basic	$ 1.80	$ 2.16	$ 1.98	$ 3.12	$ 1.85
Earnings per common share attributable to Avista Corp. shareholders—diluted:					
Earnings per common share from continuing operations	$ 1.79	$ 2.15	$ 1.89	$ 1.93	$ 1.74
Earnings per common share from discontinued operations	—	—	0.08	1.17	0.11
Total earnings per common share attributable to Avista Corp. shareholders—diluted	$ 1.79	$ 2.15	$ 1.97	$ 3.10	$ 1.85
Dividends declared per common share	$ 1.43	$ 1.37	$ 1.32	$ 1.27	$ 1.22
Book value per common share	$ 26.41	$ 25.69	$ 24.53	$ 23.84	$ 21.61

Avista Corporation

(in thousands, except per share data and ratios)

Years Ended December 31,

	2017	2016	2015	2014	2013
Total Assets at Year-End:					
Avista Utilities	$ 5,177,878	$ 4,975,555	$ 4,601,708	$ 4,357,760	$ 3,930,251
AEL&P	278,688	273,770	265,735	263,070	—
Other	73,241	60,430	39,206	80,141	81,282
Total [1]	$ 5,529,807	$ 5,309,755	$ 4,906,649	$ 4,700,971	$ 4,011,533
Long-Term Debt and Capital Leases (including current portion)	$ 1,769,237	$ 1,682,004	$ 1,573,278	$ 1,487,126	$ 1,262,036
Nonrecourse Long-Term Debt of Spokane Energy (including current portion)	$ —	$ —	$ —	$ 1,431	$ 17,838
Long-Term Debt to Affiliated Trusts	$ 51,547	$ 51,547	$ 51,547	$ 51,547	$ 51,547
Total Avista Corp. Shareholders' Equity	$ 1,729,828	$ 1,648,727	$ 1,528,626	$ 1,483,671	$ 1,298,266
Ratio of Earnings to Fixed Charges [2]	2.95	3.32	3.13	3.39	3.02

(1) The total assets at year-end for the year 2013 exclude the total assets associated with Ecova of $339.6 million.

(2) See Exhibit 12 for computations.

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

BUSINESS SEGMENTS

As of December 31, 2017, we have two reportable business segments, Avista Utilities and AEL&P. We also have other businesses which do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp. See "Part I, Item 1. Business—Company Overview" for further discussion of our business segments.

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

	2017	2016	2015
Avista Utilities	$ 114,716	$ 132,490	$ 113,360
AEL&P	9,054	7,968	6,641
Ecova—Discontinued operations	—	—	5,147
Other	(7,854)	(3,230)	(1,921)
Net income attributable to Avista Corporation shareholders	$ 115,916	$ 137,228	$ 123,227

EXECUTIVE LEVEL SUMMARY

Overall Results

Net income attributable to Avista Corp. shareholders was $115.9 million for 2017, a decrease from $137.2 million for 2016.

The decrease in earnings was due to a decrease in earnings at Avista Utilities and an increase in losses at our other businesses. These were partially offset by an increase in earnings at AEL&P for 2017.

Avista Utilities' earnings decreased for 2017 primarily due to costs related to the pending acquisition by Hydro One (see further discussion at "Pending Acquisition by Hydro One" below), which are not being passed through to customers. Further, since a significant portion of these acquisition costs are not deductible for income tax purposes, earnings reflect the full amount of such costs. Excluding acquisition costs, there was a slight increase in other operating expenses, primarily due to an increase in generation and distribution maintenance costs and transmission operating costs. In addition, there were increases in depreciation and amortization and interest expense. Our 2016 requests for general rate increases in Washington were denied. See further discussion at "2016 Washington General Rate Cases" below and "Regulatory Matters" for additional discussion surrounding these requests and all of our other general rate cases.

In addition to the increases in costs described above, there was an increase in income tax expense during 2017, primarily due to recent changes in the federal income tax law, which is discussed at "Federal Income Tax Law Changes" below. The increase in costs was partially offset by an increase in gross margin (operating revenues less resource costs) as a result of general rate increases in Idaho and Oregon, customer growth and lower electric resource costs. See "Results of Operations—Overall—Non-GAAP Financial Measures" for further discussion of gross margin.

AEL&P earnings increased for 2017 resulting from an increase in revenue due to a general rate increase, higher electric loads and a slight increase in residential and commercial customers. During 2017, there was a customer refund charge related to a settlement agreement in AEL&P's electric general rate case which partially offset the increased revenues. There was also an increase in operating expenses for 2017 and a decrease in AFUDC and capitalized interest due to the construction of an additional back-up generation plant completed in 2016.

The increase in losses at our other businesses for 2017 was primarily related to an increase in income tax expense resulting from the new federal income tax law. There were also renovation expenses and increased compliance costs at one of our subsidiaries as well as impairment charges associated with two of our equity investments.

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).

2016 Washington General Rate Cases

In December 2016, the WUTC issued an order related to our Washington electric and natural gas general rate cases that were originally filed in February 2016. The WUTC order denied the Company's proposed electric and natural gas rate increase requests totaling $43.0 million. Accordingly, our electric and natural gas retail rates remained unchanged in Washington State for 2017.

As a result of the above WUTC decision, for 2017 we expected to earn below our authorized return on equity (ROE) and we expected to experience earnings contraction of $0.20 to $0.30 per diluted share as compared to 2016 actual results. However, our actual 2017 earnings were not as negatively affected as we anticipated primarily due to lower resource costs, which resulted from higher than normal hydroelectric generation and lower than forecasted natural gas prices. Our resource optimization activities also contributed to lower resource costs. Our original expectation for the Energy Recovery Mechanism (ERM) in Washington was to be in an expense position within the 90 percent customers/10 percent shareholders sharing band, whereas actual results were a benefit position within the 75 percent customers/25 percent shareholders sharing band. This represented a change of approximately $12 million for our portion of the ERM.

In addition to lower resource costs, we had lower than expected other operating expenses (not including the Hydro One acquisition costs) due to lower pension and medical expenses, lower labor costs due to more of the workforce being utilized for capital projects versus non-capital projects, and lower hardware and software information technology maintenance resulting from the timing of capital projects. We also had lower than expected depreciation expense and net financing expenses.

The lower costs described above were offset during 2017 by the Hydro One acquisition costs and the effect of federal income tax law changes, which were not contemplated in our original expectations for 2017.

Pending Acquisition by Hydro One

On July 19, 2017, Avista Corp. entered into a Merger Agreement that provides for Avista Corp. to become an indirect, wholly owned subsidiary of Hydro One. Subject to the satisfaction or waiver of specified closing conditions, including approval by regulatory agencies, the transaction is expected to close during the second half of 2018. At the effective time of the acquisition, each share of Avista Corp. common stock issued and outstanding other than shares of Avista Corp. common stock that are owned by Hydro One, Olympus Holding Corp., a wholly owned subsidiary of Hydro One (US parent), and Olympus Corp., a wholly owned subsidiary of US parent (Merger Sub) or any of their respective subsidiaries, will be converted automatically into the right to receive an amount in cash equal to $53, without interest. For further information, see Notes 4 and 19 of the "Notes to Consolidated Financial Statements."

Federal Income Tax Law Changes

On December 22, 2017, the TCJA was signed into law. The legislation includes substantial changes to the taxation of individuals as well as U.S. businesses, multi-national enterprises, and other types of taxpayers. Highlights of provisions most relevant to Avista Corp. include:

- A permanent reduction in the statutory corporate tax rate from 35 percent to 21 percent, beginning with tax years after 2017;
- Statutory provisions requiring that excess deferred taxes associated with public utility property be normalized using the average rate assumption method (ARAM) for determining the timing of the return of excess deferred taxes to customers. Excess deferred taxes result from revaluing deferred tax assets and liabilities based on the newly enacted tax rate instead of the previous tax rate, which, for most rate-regulated utilities like Avista Utilities and AEL&P, results in a net benefit to customers that will be deferred as a regulatory liability and passed through to customers over future periods;
- Repeal of the corporate alternative minimum tax (AMT);
- Bonus depreciation (expensing of capital investment on an accelerated basis) was removed as a deduction for property predominantly used in certain rate-regulated businesses (like Avista Utilities and AEL&P), but is still allowed for our non-regulated businesses;
- The deduction for interest expense that is properly allocable to certain rate-regulated trades or businesses is still allowed under the new law, but the deduction is now limited for our non-regulated businesses; and
- Net operating loss (NOL) carryback deductions were eliminated, but carryforward deductions are allowed indefinitely with some annual limitations versus the previous 20-year limitation.

Our analysis and interpretation of this legislation is complete as it relates to amounts recorded as of December 31, 2017 and based on our evaluation, the reduction of the U.S. corporate income tax rate required a revaluation of our deferred income tax assets and liabilities (including the value of our net operating loss carryforwards) during the fourth quarter of 2017, the period in which the tax legislation was enacted. Because we are predominantly a rate-regulated entity, the net effect of the legislation was recorded as a regulatory liability on the Consolidated Balance Sheets and it will be returned to customers through the ratemaking process in future periods. The total net amount of the regulatory liability associated with the TCJA was $442.3 million as of December 31, 2017, which is made up of $339.9 million in excess deferred taxes and $102.4 million for the income tax gross-up of those excess deferred taxes (which, together with the excess deferred tax amount, reflects the revenue amounts to be refunded to customers through the regulatory process). We expect the Avista Utilities plant related amounts will be returned to customers over a period of approximately 36 years using the ARAM. We expect the AEL&P plant related amounts to be returned to customers over a period of approximately 40 years. We do not currently have an estimate for the amortization period for the regulatory liability attributable to non-plant excess deferred taxes items as we are waiting for additional implementation guidance from various regulatory agencies. We estimate that customers could see a benefit going forward of approximately $50 to $60 million annually, excluding amounts that are currently being deferred for 2018 which will be returned to customers at a later date, due to the return of the excess deferred taxes along with lower federal income tax rates which will be reflected in future rates.

Because we have deferred income tax assets and liabilities related to our unregulated subsidiaries and certain utility expenses which are not passed through to our customers, the impact of the revaluation of our deferred income tax assets and liabilities was recorded as a $10.2 million (net) discrete adjustment to income tax expense in the fourth quarter of 2017. Of this income tax expense amount, $7.5 million related to Avista Utilities and $2.7 million related to our other businesses. We expect an annual reduction to net earnings going forward of approximately $0.05 to $0.06 per diluted share due to expenses that are not passed through to our customers at Avista Utilities that will be ongoing into the future. These expenses will reduce earnings in future periods because we will receive a smaller tax deduction for these expenses than we did prior to the enactment of the TCJA. These expenses include SERP expenses, executive stock compensation and charitable donations (including the additional donations that are required as part of the Merger Agreement with Hydro One).

The impact of the tax law changes going forward may differ from the amounts above due to, among other things, changes in interpretations and assumptions the Company has made; federal tax regulations, guidance or orders that may be issued by the U.S. Department of the Treasury, Internal Revenue Service, and our regulatory commissions; and actions the Company may take as a result of the tax law changes.

Overall, we expect a net benefit to our customers as a result of tax law changes; however, because of the TCJA and the changes to our accumulated deferred income tax balances, our net utility property for regulatory purposes (rate base) is likely to increase in future periods, which would increase our annual revenue requirements and offset some of the benefits to customers from tax rate reductions. Rate base is likely to increase because, for ratemaking purposes, net deferred tax liabilities are netted against our rate base.

Because most of the provisions of the TCJA are effective as of January 1, 2018 (including a reduction of the income tax rate to 21 percent), but our customers' rates continue to have the 35 percent corporate tax rate built in from prior general rate cases, we filed Petitions in December 2017 with the WUTC and OPUC requesting orders authorizing the deferral of the accounting impact of the change in federal income tax expense caused by the enactment of the TCJA. The IPUC on its own ordered deferred accounting for all jurisdictional utilities in January 2018. We are requesting to defer the impact of the change in federal income tax expense beginning in January 2018 forward until all benefits are properly captured through the deferral process and refunded to customers through tariffs to be reviewed and implemented in future rate proceedings. The IPUC has requested a report on the estimated overall benefit to customers related to the impacts of the TCJA by March 30, 2018. The WUTC has issued a bench request in our 2017 electric and natural gas general rate cases requesting such information by February 28, 2018.

Although it is unclear when or how capital markets, credit rating agencies, the FERC or state public utility commissions may respond to this legislation, we expect that certain financial metrics used by credit rating agencies to evaluate the Company will be negatively impacted as a result of the TCJA. This is primarily due to our expectation that future cash flows from operations will be negatively impacted going forward for the following reasons:

- Because of accelerated depreciation, including bonus depreciation, and other tax deductions, we have paid less in actual cash taxes than what was being collected from customers. The temporary timing differences between cash paid as income taxes and tax expense recorded for GAAP resulted in the recording of a net deferred tax liability. This temporary timing difference from prior years will ultimately reverse with taxable income and corresponding income taxes increasing in future years;
- Lowering the corporate tax rate to 21 percent resulted in excess deferred taxes, which must be returned to customers using the ARAM discussed above. This will result in a reduction of future revenue as we refund the excess deferred taxes to customers;
- Lowering the tax rate to 21 percent will result in customers' future rates having an embedded 21 percent tax rate rather than the 35 percent tax rate, which will result in lower future revenue (which will be offset by lower actual tax expenses); and
- The loss of the bonus depreciation tax deduction for 2018 and 2019 results in less depreciation as a tax deduction in those years, which will increase our taxable income and result in us having to pay taxes earlier than we had projected under the old tax law.

There may be other material adverse effects resulting from the legislation that we have not yet identified. These effects have resulted in Moody's placing a negative outlook on our credit rating and could result in Moody's taking further negative action or other credit rating agencies taking similar action. These actions by credit rating agencies may make it more difficult and costly for us to issue future debt securities and could increase borrowing costs under our credit facilities.

See "Note 11 of the Notes to Consolidated Financial Statements" and "Risk Factors" for additional information regarding the TCJA and its specific impacts to our financial statements.

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.

AVISTA UTILITIES

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 WUTC in February 2015. New electric and natural gas rates were effective on January 11, 2016.

The WUTC-approved rates were 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 WUTC 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 ROE.

WUTC Order Denying Industrial Customers of Northwest Utilities / Public Counsel Joint Motion for Clarification, WUTC Staff Motion to Reconsider and WUTC 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 WUTC. In the Motion for Clarification, ICNU and PC requested that the WUTC 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 WUTC's Order.

On January 19, 2016, the WUTC Staff, which is a separate party in the general rate case proceedings from the WUTC Advisory Staff, filed a Motion to Reconsider with the WUTC. In its Motion to Reconsider, the Staff provided calculations and explanations that suggested that the electric revenue decrease should have been $27.4 million instead of $8.1 million, based on its reading of the WUTC's Order. Further, on February 4, 2016, the WUTC 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's Power Cost Update." Within this Motion, WUTC Staff updated its suggested electric revenue decrease to $19.6 million.

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

On February 19, 2016, the WUTC issued an order (Order 06) denying the Motions summarized above and affirming 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 WUTC's Order 05 and Order 06 described above that concluded our 2015 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 WUTC 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 WUTC 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 WUTC erred in applying the "end results test" to set rates for our electric operations that are not supported by the record; (4) the WUTC did not correct its calculation of our electric rates after significant errors were brought to its attention; and (5) the WUTC's calculation of our electric rates lacks substantial evidence.

PC is requesting that the Court (1) vacate or set aside portions of the WUTC's orders; (2) identify the errors contained in the WUTC'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 WUTC 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. The matter was certified on April 29, 2016 and accepted by the Court of Appeals on July 29, 2016. On July 7, 2017, ICNU filed a brief in support of PC and the WUTC and Avista Corp. responded. Oral argument was held on October 24, 2017 before the court. A decision from the Court is expected sometime in 2018.

In its brief to the Court, the WUTC, while defending the use of its attrition adjustment, nevertheless requested a partial remand back to the WUTC to reevaluate its implementation of our power cost update as part of the 2015 general rate case, doing so by means of a supplemental evidentiary hearing. The power cost update at issue represents approximately $12.0 million of costs.

The new rates established by Order 05 will continue in effect while the Petition for Judicial Review is being considered. We believe the WUTC'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 WUTC, it may result in a refund liability to customers of up to $9.5 million, which is net of a refund for Washington electric customers of approximately $2.5 million related to the 2016 provision for earnings sharing that we have already accrued. The potential refund liability amount is limited to 2016 revenues and would not impact 2017 revenues collected from customers.

2016 General Rate Cases

In December 2016, the WUTC issued an order related to our Washington electric and natural gas general rate cases that were originally filed with the WUTC in February 2016. The WUTC order denied the Company's proposed electric and natural gas rate increase requests of $38.6 million and $4.4 million, respectively. Accordingly, our electric and natural gas retail rates remained unchanged in Washington State following the order.

The primary reason given by the WUTC in reaching its conclusion was that, in our request, we did not follow an "appropriate methodology" to show the existence of attrition, as between historical data and current and projected data. In support of its decision, the WUTC stated that we did not demonstrate that our current revenue was insufficient for covering costs and providing the opportunity to earn a reasonable return during the 2017 rate period. The WUTC also stated that we did not demonstrate that our capital expenditures and increased operating costs are both necessary and immediate.

We determined that an appeal of the WUTC's decision to the courts would involve a significant amount of uncertainty regarding the level of success of such an appeal, as well as the timing of any value that might come following a process that would take between one and two years. The Company concluded greater long-term value could be achieved through focusing on new general rate cases than through appealing the WUTC's decision in the courts.

2017 General Rate Cases

On May 26, 2017, we filed two requests with the WUTC to recover costs related to power supply and operating costs as well as capital investments made since the last determination of our rate base in the 2015 Washington general rate cases.

The two filings are summarized as follows:

Power Cost Rate Adjustment

The first filing was an electric only power cost rate adjustment (PCRA) that was designed to update and reset power supply costs, effective September 1, 2017. We requested an overall increase in billed electric rates of 2.9 percent (designed to increase annual electric revenues by $15.0 million). On August 10, 2017, the PCRA filing was denied by the WUTC.

An increased level of power supply costs is included in our pending general rate case in Washington, which is scheduled to conclude by April 26, 2018. The denial of the PCRA by the WUTC does not affect our general rate requests discussed below.

General Rate Requests

The second request related to electric and natural gas general rate cases.

We filed three-year rate plans for electric and natural gas and have requested the following for each year (dollars in millions):

	Electric		Natural Gas	
Effective Date	**Proposed Revenue Increase**	**Proposed Base Rate Increase**	**Proposed Revenue Increase**	**Proposed Base Rate Increase**
May 1, 2018 (1)	$ 54.4	11.1%	$ 6.6	7.5%
May 1, 2019 (1) (2)	$ 13.5	2.5%	$ 3.7	3.9%
May 1, 2020 (1) (2)	$ 13.9	2.5%	$ 3.8	3.9%

(1) The revenue and base rate increases in the table above reflect reductions from what was originally filed primarily due to changes in the timing of planned capital projects.

(2) As a part of the electric rate plan, we have proposed to update power supply costs through a Power Supply Update, the effects of which would also go into effect on May 1, 2019 and May 1, 2020. The requested revenue increases for 2019 and 2020 do not include any power supply adjustments.

Our request is based on a proposed ROR of 7.76 percent with a common equity ratio of 50.0 percent and a 9.9 percent ROE.

As a part of the three-year rate plan, if approved, we would not file another general rate case until June 1, 2020, with new rates effective no earlier than May 1, 2021.

The major drivers of these general rate case requests is to recover the costs associated with our capital investments to replace infrastructure that has reached the end of its useful life, as well as respond to the need for reliability and technology investments required to maintain our integrated energy services grid. Among the capital investments included in the filings are:

- Major hydroelectric investments at the Little Falls and Nine Mile hydroelectric plants.
- Generator maintenance at the Kettle Falls biomass plant that will ensure efficient generation and operations.
- The ongoing project to systematically replace portions of natural gas distribution pipe in our service area that were installed prior to 1987, as well as replacement of other natural gas service equipment.
- Transmission and distribution system and asset maintenance, such as wood pole replacements, feeder upgrades, and substation and transmission line rebuilds to maintain reliability for our customers.
- Technology upgrades that support necessary business processes and operational efficiencies that allow us to effectively manage the utility and serve customers.
- A refresh of the customer-facing website, providing relevant information, greater accessibility on mobile devices, easier navigation, and a streamlined payment experience.

The WUTC has up to 11 months to review the general rate case filings and issue a decision, which is scheduled to be issued by April 26, 2018.

On October 27, 2017, WUTC Staff and other parties to our electric and natural gas general rate cases filed their testimony. These parties recommended lower revenue requirements than what we proposed in our original filings. WUTC Staff also recommended that our power cost adjustment of approximately $16 million be denied, and that the existing level of power supply costs included in base rates be continued until either (a) our next general rate case or (b) the cumulative deferral balance in the ERM drops below $10 million.

Additionally, the WUTC Staff recommended the exclusion of our 2016 settlement costs of interest rate swaps from the cost of capital calculation. The total amount of 2016 settlement costs was $54.0 million, with approximately 60 percent of this total being allocable to Washington.

In addition to our 2016 settlement costs of interest rate swaps, we have a net regulatory asset of $8.8 million for interest rate swaps settled during 2017, and a net regulatory asset of $66.0 million for unsettled interest rate swaps as of December 31, 2017 related to forecasted debt issuances. Of those amounts, approximately 60 percent are allocable to Washington. If recovery of the 2016 settlement costs referenced above are not approved by the WUTC, this could change our current conclusion that 2017 settlement costs of interest rate swaps and the unsettled interest rate swaps are probable of recovery through rates. If we concluded that recovery of these swap settlement costs was no longer probable, we would be required to derecognize the related regulatory assets and liabilities with an adjustment through the income statement, and any subsequent gains and losses would be recognized through the income statement rather than being recorded as a regulatory asset or liability.

Interest rate swaps are a tool used throughout multiple industries to manage interest rate risk. They also provide certainty for future cash flows associated with future borrowings. Since interest costs are included in our costs of service to be recovered from our customers, we have used this tool to manage these costs for the benefit of our customers. The settlement of interest rate swaps results in either a benefit or a cost to us which, in either case, has historically been reflected in rates authorized by the WUTC in general rate cases. Accordingly, we still believe the interest rate swap payments are probable of recovery and will continue to work through the rate case process. Depending on the outcome of this proceeding, we could determine to not manage interest rate risk through swap transactions in the future.

Idaho General Rate Cases

2015 General Rate Cases

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

The settlement agreement increased annual electric base revenues by 0.7 percent (designed to increase annual electric revenues by $1.7 million) and annual natural gas base revenues by 3.5 percent (designed to increase annual natural gas revenues by $2.5 million). The settlement was 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.

2016 General Rate Cases

In December 2016, the IPUC approved a settlement agreement between us and other parties, concluding our electric general rate case originally filed in May 2016. New rates were effective on January 1, 2017. We did not file a natural gas general rate case in 2016.

The settlement agreement increased annual electric base rates by 2.6 percent (designed to increase annual electric revenues by $6.3 million). The settlement was based on a ROR of 7.58 percent with a common equity ratio of 50 percent and a 9.5 percent ROE.

2017 General Rate Cases

On December 28, 2017, the IPUC approved a settlement agreement between us and other parties to our electric and natural gas general rate cases. New rates were effective on January 1, 2018 and additional rate changes will take effect on January 1, 2019.

The settlement agreement is a two-year rate plan and has the following electric and natural gas base rate changes each year, which are designed to result in the following increases in annual revenues (dollars in millions):

	Electric		Natural Gas	
Effective Date	**Revenue Increase**	**Base Rate Increase**	**Revenue Increase**	**Base Rate Increase**
January 1, 2018	$ 12.9	5.2%	$ 1.2	2.9%
January 1, 2019	$ 4.5	1.8%	$ 1.1	2.7%

The settlement agreement is based on a ROR of 7.61 percent with a common equity ratio of 50.0 percent and a 9.5 percent ROE.

As a part of the two-year rate plan the Company will not file a new general rate case for a new rate plan to be effective prior to January 1, 2020.

Oregon General Rate Cases

2015 General Rate Case

In February 2016, the OPUC issued a preliminary order (and a final order in March 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 provided an 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.

2016 General Rate Case

In September 2017, the OPUC approved a settlement agreement between us and other parties to our natural gas general rate case that was filed with the OPUC in November 2016, which resolved all issues in the case.

The OPUC approved rates designed to increase annual base revenues by 5.9 percent or $3.5 million. A rate adjustment of $2.6 million became effective October 1, 2017, and a second adjustment of $0.9 million became effective on November 1, 2017 to cover specific capital projects identified in the settlement agreement, which were completed in October.

In addition, in the settlement agreement, we agreed to non-recovery of certain utility plant expenditures, which resulted in a write-off of $0.8 million in the second quarter of 2017.

The settlement agreement reflects a 7.35 percent ROR with a common equity ratio of 50 percent and a 9.4 percent ROE.

AMI Project

In March 2016, the WUTC granted our Petition for an Accounting Order to defer and include in a regulatory asset the undepreciated value of our existing Washington electric meters for the opportunity for later recovery. This accounting treatment is related to our plans to replace approximately 253,000 of our existing electric meters with new two-way digital meters and the related software and support services through our AMI project in Washington State. Replacement of the meters is expected to begin in the second half of 2018. As of December 31, 2017, the estimated undepreciated value for the existing meters is $24.3 million.

In May 2017, we filed a Petition with the WUTC requesting deferred accounting treatment for the investment costs associated with the Washington AMI project, including components such as meter communication networks, information management systems and natural gas encoder receiver transmitters (ERT). The Petition requested the deferral and inclusion in a regulatory asset of all AMI investment costs over the multi-year implementation period, until the costs could be reviewed for prudence in a future regulatory proceeding and recovered through retail rates. Through discussions with WUTC staff, we developed an alternative proposal to our original Petition and in September 2017, the WUTC approved our alternative proposal to defer the depreciation expense associated with AMI, along with a carrying charge, and to seek recovery of the deferral and carrying charge in a future general rate case. Cost savings, such as reduced meter reading costs, will occur during the implementation period which will offset a portion of the AMI costs not being deferred. The WUTC also approved our request to defer the undepreciated net book value of existing natural gas ERTs (consistent with the accounting treatment we obtained on our existing electric meters) that will be retired as part of the AMI project.

In May 2017, we filed Petitions with the IPUC and the OPUC requesting a depreciable life of 12.5 years for the meter data management system (MDM) related to the AMI project and both the IPUC and the OPUC approved the depreciable life. In addition, in connection with the recently completed Idaho electric general rate case (discussed above), the settling parties agreed to cost recovery of Idaho's share of the MDM system, effective January 1, 2019. In connection with the approval of the Oregon general rate case settlement (discussed above), the OPUC approved cost recovery of Oregon's share of the MDM system, effective November 1, 2017.

ALASKA ELECTRIC LIGHT AND POWER COMPANY

Alaska General Rate Case

In November 2017, the RCA approved an all-party settlement agreement related to AEL&P's electric general rate case, which was originally filed in September 2016. The settlement agreement is designed to increase base electric revenue by 3.86 percent or $1.3 million, making permanent the interim rate increase approved by the RCA in 2016.

In addition, AEL&P agreed to retain $0.9 million less revenue from the Greens Creek Mine than what was included in the original general rate case request. As such, in 2017, AEL&P recorded a refund liability to customers of $1.0 million (with $0.9 million related to 2017 revenues and $0.1 million related to 2016 revenues), which will be refunded to customers during the first quarter of 2018. The amount of revenue from Greens Creek Mine that is retained by AEL&P is used to offset revenue requirements that would otherwise be required from retail customers.

The agreement reflects an 8.91 percent ROR with a common equity ratio of 58.18 percent and an 11.95 percent ROE.

AVISTA UTILITIES

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to Avista Utilities' customers with no change in gross margin (operating revenues less resource costs) or net income. In Oregon, we absorb (cost or benefit) 10 percent of the difference between actual and projected natural 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 $37.5 million as of December 31, 2017 and a liability of $30.8 million as of December 31, 2016. These deferred natural gas costs balances represent amounts due to customers.

The following PGAs went into effect in our various jurisdictions during 2015 through 2018:

Jurisdiction	PGA Effective Date	Percentage Increase / (Decrease) in Billed Rates
Washington	November 1, 2015	(15.0)%
	November 1, 2016	(8.0)%
	November 1, 2017	(5.2)%
	January 26, 2018 (1)	(7.1)%
Idaho	November 1, 2015	(14.5)%
	November 1, 2016	(7.8)%
	November 1, 2017	(2.7)%
	January 26, 2018 (1)	(7.4)%
Oregon	November 1, 2015	(14.1)%
	November 1, 2016	(6.0)%
	November 1, 2017	(2.1)%
	January 26, 2018 (1)	(3.5)%

(1) Due to declining wholesale natural gas prices that have occurred since the 2017 PGAs were filed and went into effect, we filed, and the respective commissions approved, out of cycle PGAs to reduce customer rates and pass through expected lower costs during the winter heating months, rather than waiting until the next regular PGA cycle.

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge or liability on the Consolidated Balance Sheets for future prudence review and recovery or rebate through retail rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Avista Utilities and the costs included in base retail rates. This difference in net power supply costs primarily results from changes in:

- short-term wholesale market prices and sales and purchase volumes,
- the level, availability and optimization of hydroelectric generation,
- the level and availability of thermal generation (including changes in fuel prices),
- retail loads, and
- sales of surplus transmission capacity.

The ERM is an accounting method used to track certain differences between Avista Utilities' actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for our Washington customers. Total net deferred power costs under the ERM were a liability of $23.7 million as of December 31, 2017 and a liability $21.3 million as of December 31, 2016. These deferred power cost balances represent amounts due to customers.

Under the ERM, Avista Utilities absorbs the cost or receives the benefit from the initial amount of power supply costs in excess of or below the level in retail rates, which is referred to as the deadband. The annual (calendar year) deadband amount is $4.0 million.

The following is a summary of the ERM:

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

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

Avista Utilities has a PCA mechanism in Idaho that allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. The October 1 rate adjustments recover or rebate power supply costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a liability of $6.1 million as of December 31, 2017 and a liability of $2.2 million as of December 31, 2016. These deferred power cost balances represent amounts due to customers.

Decoupling and Earnings Sharing Mechanisms

Decoupling (also known as a FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of our jurisdictions, Avista Utilities' electric and natural gas revenues are adjusted so as to be based on the number of customers in certain customer rate classes and assumed "normal" kilowatt hour and therm sales, rather than being based on actual kilowatt hour and therm sales. The difference between revenues based on the number of customers and "normal" sales and revenues based on actual usage is deferred and either surcharged or rebated to customers beginning in the following year. Only residential and certain commercial customer classes are included in our decoupling mechanisms.

Washington Decoupling and Earnings Sharing

In Washington, the WUTC approved our decoupling mechanisms for electric and natural gas for a five-year period beginning January 1, 2015. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to a 3 percent increase 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 for the calendar year just ended. These earnings tests reflect actual decoupled revenues, normalized power supply costs and other normalizing adjustments. If we earn more than our authorized ROR in Washington, 50 percent of excess earnings are rebated to customers through adjustments to existing decoupling surcharge or rebate balances.

See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Idaho 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, beginning 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).

See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

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. There will be an opportunity for interested parties to review the mechanism and recommend changes, if any, by September 2019. In Oregon, an earnings review is conducted on an annual basis. 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 rebated to customers. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Cumulative Decoupling and Earnings Sharing Mechanism Balances

As of December 31, 2017 and December 31, 2016, we had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in our various jurisdictions (dollars in thousands):

	December 31, 2017	December 31, 2016
Washington		
Decoupling surcharge	$ 14,240	$ 30,408
Provision for earnings sharing rebate	(3,420)	(5,113)
Idaho		
Decoupling surcharge	$ 3,471	$ 8,292
Provision for earnings sharing rebate	(2,350)	(5,184)
Oregon		
Decoupling surcharge/(rebate)	$ (1,168)	$ 2,021
Provision for earnings sharing rebate	—	—

See "Results of Operations—Avista Utilities" for further discussion of the amounts recorded to operating revenues in 2015 through 2017 related to the decoupling and earnings sharing mechanisms.

State Regulatory Approval Requirements Related to the Pending Acquisition by Hydro One

The following is a brief summary of the state regulatory approvals that are required for the proposed acquisition of the Company by Hydro One.

On September 14, 2017, Avista Corp. and Hydro One filed applications for approval of the acquisition with the WUTC, the IPUC, the MPSC and the OPUC, requesting approval of the transaction on or before August 14, 2018. However, the OPUC has set a procedural schedule with an end date no later than September 14, 2018. On November 21, 2017, applications for approval of the acquisition were filed with the RCA, with a statutory deadline of May 20, 2018.

The principal issue before the WUTC in the proceeding for approval of the proposed transaction will be whether the transaction is consistent with the public interest, per Washington Administrative Code 480-143-170. In addition, under the Revised Code of Washington 80.12.020, the WUTC must determine that the transaction provides a "net benefit" to the customers of the Company.

Before the IPUC may authorize such a transaction, the utility must prove that the transaction is consistent with the public interest, that the cost and rates for the utility's service will not increase as a result of the transaction, and that the new owner "has the bona fide intent and financial ability to operate and maintain said property in the public service." In addition, because the transaction includes hydropower water rights used in the generation of electric power, the director of the

Idaho Department of Water Resources must issue conditions protecting the public interest and existing water rights holders with respect to the hydropower water right to be transferred, and the IPUC must include any such conditions in its approval of the transfer.

The MPSC generally applies any of three standards to evaluate transfers of public utilities: the public interest standard, the no-harm-to-consumers standard, or the net-benefit-to-consumers standard (see Order No. 6754e in Docket. No. 02006.6.82). The MPSC seeks to assure that utility customers will receive adequate service and facilities, that utility rates will not increase as a result of the sale or transfer, and that the acquiring entity is fit, willing, and able to assume the service responsibilities of a public utility, though it has not enunciated a specific standard for approval because of the variety of situations that arise.

The OPUC must determine that the transaction "will serve the public utility's customers and is in the public interest." The OPUC interprets Oregon Revised Statute § 757.511 to impose a "net benefits" test (see Order No. 06-082, at p.3 (Docket. No. UM 1209)). This analysis must include consideration of the effect of the transaction on the amount of income taxes paid by the utility and its affiliates and the approval must adjust the utility's rates accordingly.

On February 12, 2018, OPUC Staff and other interested parties in Oregon filed their initial recommendations regarding the proposed acquisition by Hydro One. In their initial recommendation, the OPUC Staff recommended that the Commission deny the application as it was originally filed. OPUC Staff believes the application does not provide a net benefit to Avista Corp.'s customers, nor are the ring-fencing commitments adequate to protect those customers from harm. However, the OPUC Staff indicated they would not issue a final opinion until after receiving and reviewing additional testimony from us and Hydro One and they indicated they would consider a more comprehensive and functional set of interlocking, reinforcing conditions designed to help ensure that Avista Corp. customers are not harmed by the proposed merger, accompanied by a proposal with incremental benefits to customers.

The RCA will examine whether the entity seeking to acquire the controlling interest is "fit, willing, and able and whether the proposed transfer is consistent with the public interest under the criteria set forth in Alaska Statute 42.05."

Avista Corp. and Hydro One intend to work with the various commissions, their staff and other parties to try and satisfy any concerns associated with the proposed transaction.

RESULTS OF OPERATIONS—OVERALL

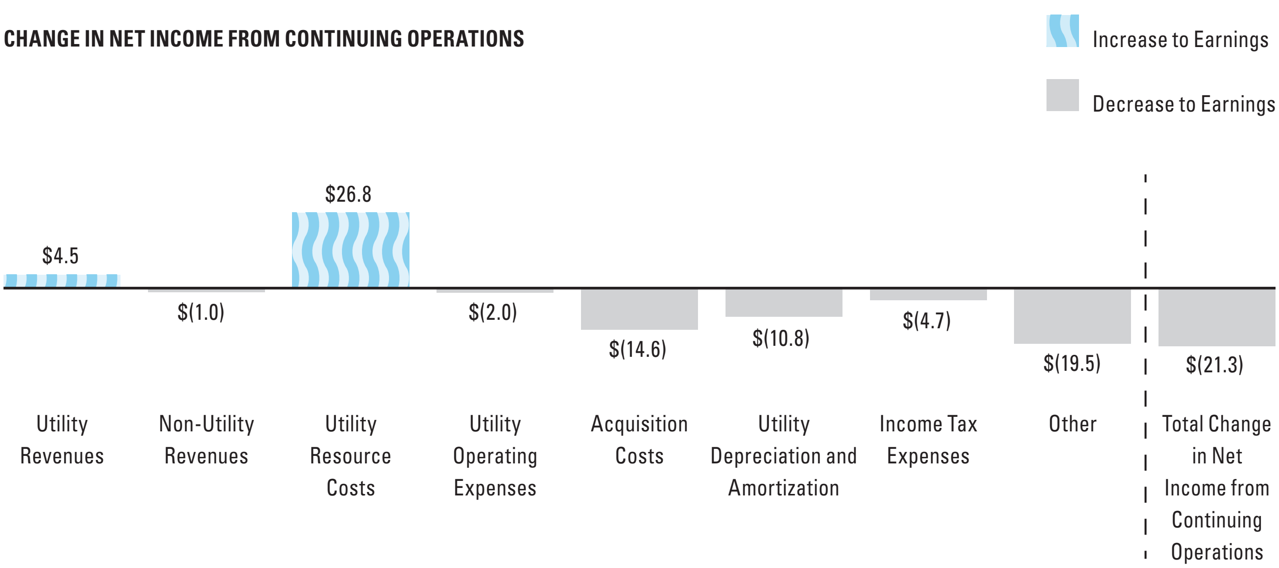
The following provides an overview of changes in our Consolidated Statements of Income. More detailed explanations are provided, particularly for operating revenues and operating expenses, in the business segment discussions (Avista Utilities, AEL&P, Ecova—Discontinued Operations and the other businesses)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

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

2017 Compared to 2016

The following graph shows the total change in net income from continuing operations for 2016 to 2017, as well as the various factors that caused such change (dollars in millions):

CHANGE IN NET INCOME FROM CONTINUING OPERATIONS



Utility revenues increased due to an increase at AEL&P, partially offset by a decrease at Avista Utilities. AEL&P's revenues increased primarily due to a general rate increase and higher retail heating loads due to weather that was cooler than the prior year. There was also a slight increase in the number of customers at AEL&P. Avista Utilities' revenues decreased primarily due to a decrease in electric and natural gas wholesale revenues and revenues from sales of fuel, mostly offset by an increase in electric and natural gas retail revenues. Retail revenues increased due to an increase in volumes and an electric general rate increase in Idaho and a natural gas general rate increase in Oregon. The higher retail sales volumes resulted from increased heating loads during the heating season, increased electric cooling loads during the summer and due to customer growth. The increased utility revenues were partially offset by decoupling rebates during 2017 due to weather that fluctuated from normal. This compares to decoupling surcharges during 2016.

Utility resource costs decreased due to a decrease at Avista Utilities. Avista Utilities' electric resource costs decreased primarily due to a decrease in purchased power (from lower wholesale prices) and a decrease in fuel for generation (due in part to increased hydroelectric generation). Natural gas resource costs decreased due to a decrease in natural gas purchased resulting from lower wholesale sales volumes.

Utility operating expenses increased due to an increase at Avista Utilities and a slight increase at AEL&P. The increase at Avista Utilities' was the result of an increase in generation and distribution maintenance costs and transmission operating costs. There was also a write-off in Oregon of utility plant associated with a general rate case settlement. The increased costs were partially offset by decreases in pension, other postretirement benefit and medical expenses.

The acquisition costs are related to the pending acquisition by Hydro One and consist primarily of consulting, banking fees, legal fees and employee time and are not being passed through to customers.

Utility depreciation and amortization increased due to additions to utility plant.

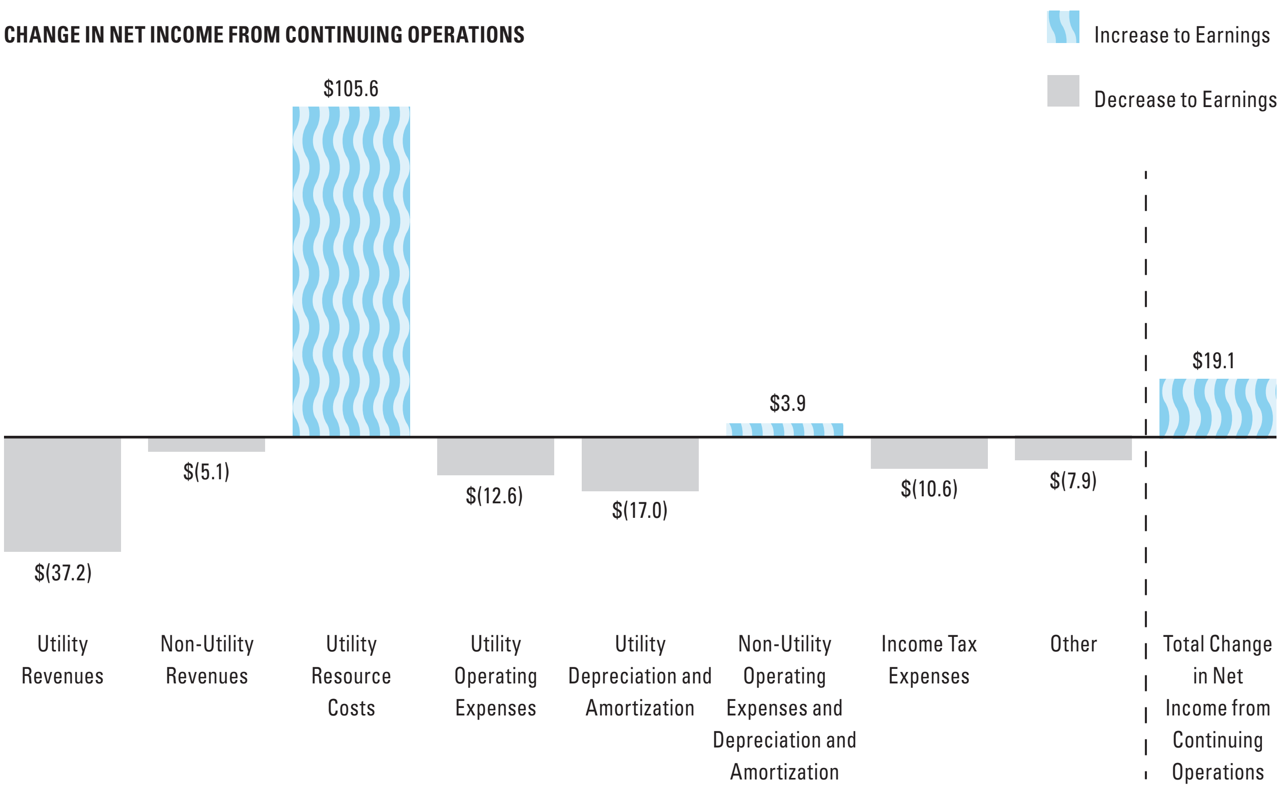
Income tax expense increased primarily due to the enactment of the TCJA in December 2017, which resulted in a non-cash charge to income tax expense of $10.2 million during 2017 from revaluing our deferred income tax assets and liabilities based on the new federal tax rate. This was partially offset by the effect of a decrease in income before income taxes. Our effective tax rate was 41.7 percent for 2017 and 36.3 percent for 2016. The effective tax rate increased due to federal income tax law changes and due to acquisition costs. The acquisition costs reduce income before income taxes, but a significant portion of these costs are not deductible for tax purposes and thus do not reduce income tax expense. See "Note 11 of the Notes to Consolidated Financial Statements" for a reconciliation of our effective income tax rate.

Other was primarily related to an increase in interest expense, due to additional debt being outstanding during 2017 as compared to 2016 and partially due to an increase in the overall interest rate. There was also an increase in utility taxes other than income taxes primarily due to revenue-related taxes, which resulted from an increase in electric and natural gas retail revenue. Lastly, there were impairments recorded during 2017 on two of our equity investments.

2016 Compared to 2015

The following graph shows the total change in net income from continuing operations for 2015 to 2016, as well as the various factors that caused such change (dollars in millions):

CHANGE IN NET INCOME FROM CONTINUING OPERATIONS



Utility revenues decreased due to a decrease at Avista Utilities, partially offset by a slight increase in AEL&P's revenues. Avista Utilities' electric revenues decreased primarily due to lower retail electric loads caused by weather fluctuations throughout the period, a general rate decrease in Washington and lower wholesale revenues resulting from lower volumes and lower wholesale prices. These revenue decreases were partially offset by a general rate increase in Idaho, the expiration of the ERM rebate to customers in Washington, increased decoupling revenues and a lower provision for earnings sharing. Natural gas revenues decreased primarily due to a decrease in wholesale activity (both a decrease in volumes and prices) and lower retail revenues due to lower prices, partially offset by higher natural gas heating volumes. The decreases in natural gas revenues were partially offset by general rate increases and higher decoupling revenues.

Non-utility revenues decreased 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 during the first quarter of 2015. After the transfer, the revenue is included in Avista Utilities' revenues. The contract expired during December 2016.

Utility resource costs decreased due to a decrease at Avista Utilities. Avista Utilities' electric resource costs decreased primarily due to a decrease in purchased power (from lower volumes purchased and lower wholesale prices) and a decrease in fuel for generation (due in part to increased hydroelectric generation). Natural gas resource costs decreased due to a decrease in natural gas purchased resulting from lower volumes and lower prices.

Utility operating expenses increased due to an increase at Avista Utilities and a slight increase at AEL&P. Avista Utilities' portion of other operating expenses increased due to an increase in medical costs, electric generation operating and maintenance expenses, natural gas distribution expenses and other postretirement benefit expenses.

Utility depreciation and amortization increased due to additions to utility plant.

Income tax expense increased primarily due to an increase in income before income taxes, partially offset by excess tax benefits of $1.6 million during 2016 relating to the settlement of share-based payment awards. See "Note 2 of the Notes to Consolidated Financial Statements" for further discussion of the excess tax benefits. Our effective tax rate was 36.3 percent for both 2016 and 2015.

Other was primarily related to an increase in interest expense, due to additional debt being outstanding during 2016 as compared to 2015 and partially due to an increase in the overall interest rate. Also, there were losses on investments at our subsidiaries, mainly due to initial organization costs and management fees associated with a new investment.

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, which is also a non-GAAP financial measure.

Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included (excluded) in the most directly comparable measure calculated and presented in accordance with GAAP. The presentation of electric gross margin and natural gas gross margin is intended to supplement an understanding of operating performance. We use these measures to determine whether the appropriate amount of revenue is being collected from our customers to allow for the recovery of energy resource costs and 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 for Avista Utilities since each business has different cost sources, cost recovery mechanisms and jurisdictions, such that 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.

RESULTS OF OPERATIONS—AVISTA UTILITIES

2017 Compared to 2016

The following table presents Avista Utilities' operating revenues, resource costs and resulting gross margin for the years ended December 31 (dollars in millions):

	Electric		Natural Gas		Intracompany		Total	
	2017	2016	2017	2016	2017	2016	2017	2016
Operating revenues	$ 980,390	$ 996,959	$ 474,649	$ 470,894	$ (84,680)	$ (95,215)	$ 1,370,359	$ 1,372,638
Resource costs	331,254	360,591	264,589	273,976	(84,680)	(95,215)	511,163	539,352
Gross margin	$ 649,136	$ 636,368	$ 210,060	$ 196,918	$ —	$ —	$ 859,196	$ 833,286

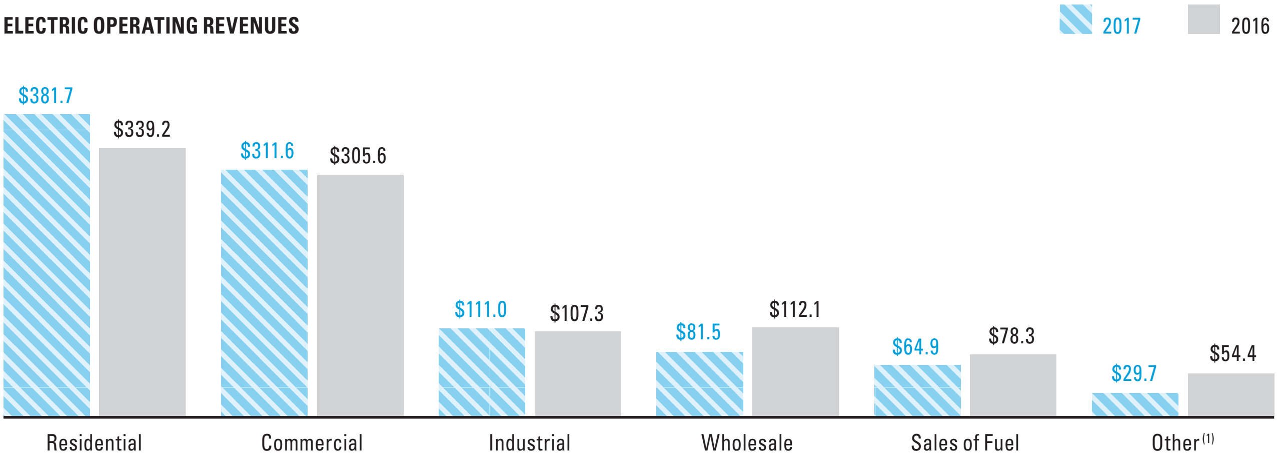
The gross margin on electric sales increased $12.8 million and the gross margin on natural gas sales increased $13.1 million. The increase in electric gross margin was primarily due to a general rate increase in Idaho, customer growth, increases in loads not subject to decoupling and lower resource costs. For 2017, we recognized a pre-tax benefit of $4.6 million under the ERM in Washington compared to a benefit of $5.1 million for 2016.

The increase in natural gas gross margin was primarily due to a general rate increase in Oregon, customer growth and increases in loads not subject to decoupling.

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

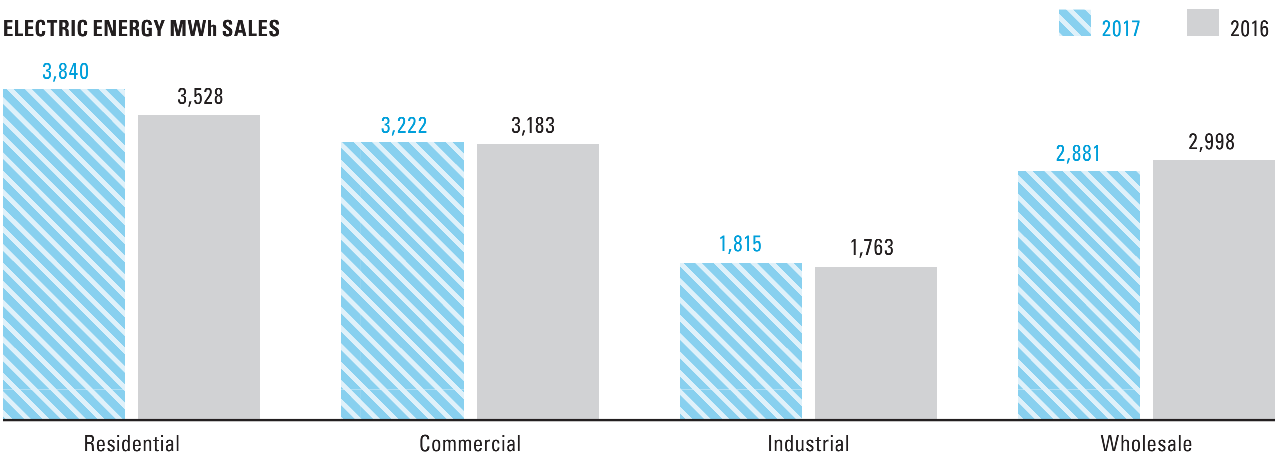
The following graphs present Avista Utilities' electric operating revenues and megawatt-hour (MWh) sales for the years ended December 31 (dollars in millions and MWhs in thousands):

ELECTRIC OPERATING REVENUES



(1) This balance includes public street and highway lighting, which is considered part of retail electric revenues and it also includes revenues and rebates from decoupling.

ELECTRIC ENERGY MWh SALES



The following table presents Avista Utilities' decoupling and customer earnings sharing mechanisms by jurisdiction that are reflected in utility electric operating revenues for the years ended December 31 (dollars in thousands):

	Electric Operating Revenues	
	2017	**2016**
Washington		
Decoupling surcharge (rebate)	$ (4,982)	$ 11,324
Provision for earnings sharing [1]	(1,182)	221
Idaho		
Decoupling surcharge (rebate)	$ (3,238)	$ 6,025
Provision for earnings sharing [2]	N/A	711

(1) The provision for earnings sharing in Washington for 2017 represents a $0.2 million adjustment for the 2016 provision for earnings sharing and $1.0 million relating to 2017 earnings. The provision for earnings sharing in Washington in 2016 resulted from a $2.5 million reduction in the 2015 provision for earnings sharing (which increased 2016 revenues) offset by a $2.3 million provision for earnings sharing for 2016 electric operations.

(2) The provision for earnings sharing in Idaho in 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.

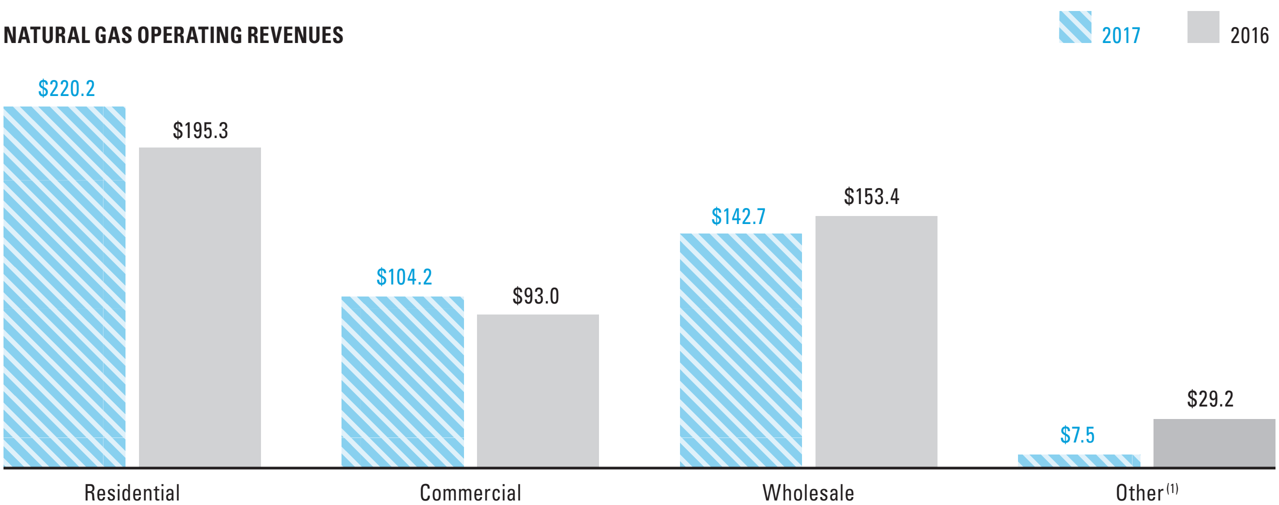
(N/A) This mechanism did not exist during this time period.

Total electric revenues decreased $16.6 million for 2017 as compared to 2016, primarily reflecting the following:

- a $52.0 million increase in retail electric revenues due to an increase in total MWhs sold (increased revenues $36.6 million) and an increase in revenue per MWh (increased revenues $15.4 million).
  - The increase in total retail MWhs sold was the result of weather that was cooler than the prior year during the heating season (which increased electric heating loads) and warmer than the prior year during the cooling season (which increased electric cooling loads), as well as customer growth. Compared to 2016, residential electric use per customer increased 8 percent and commercial use per customer did not change materially. Heating degree days in Spokane were 3 percent above normal and 17 percent above 2016. Cooling degree days in Spokane were 40 percent above normal and 57 percent above the prior year.
  - The increase in revenue per MWh was primarily due to a general rate increase in Idaho and a greater portion of retail revenues from residential customers in 2017.
- a $30.6 million decrease in wholesale electric revenues due to a decrease in sales prices (decreased revenues $27.3 million) and a decrease in sales volumes (decreased revenues $3.3 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $13.4 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 2017, $35.3 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For 2016, $44.0 million of these sales were made to our natural gas operations.
- a $25.6 million decrease in electric revenue due to decoupling. Weather was cooler than normal during the heating season and warmer than normal during the cooling season in 2017, which resulted in decoupling rebates for 2017. Weather was warmer than normal during the heating season in 2016, which resulted in significant decoupling surcharges. Decoupling mechanisms are not affected by fluctuations in weather compared to prior year; rather, they are only affected by weather fluctuations as compared to normal weather.

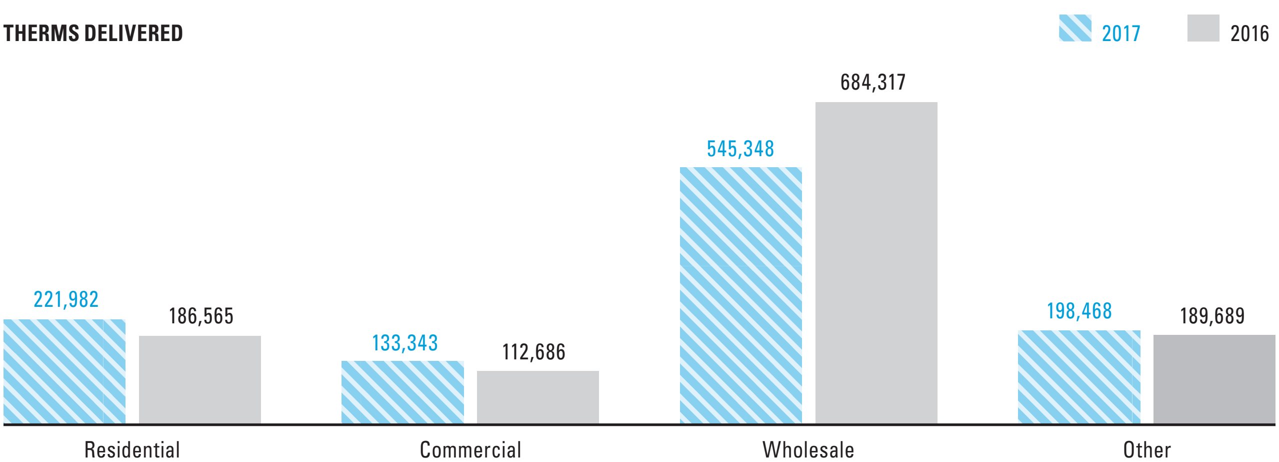
The following graphs present Avista Utilities' natural gas operating revenues and therms delivered for the years ended December 31 (dollars in millions and therms in thousands):

NATURAL GAS OPERATING REVENUES



(1) This balance includes interruptible and industrial revenues, which are considered part of retail natural gas revenues and it also includes revenues and rebates from decoupling.

THERMS DELIVERED



The following table presents Avista Utilities' decoupling and customer earnings sharing mechanisms by jurisdiction that are reflected in utility natural gas operating revenues for the years ended December 31 (dollars in thousands):

	Natural Gas Operating Revenues	
	2017	2016
Washington		
Decoupling surcharge (rebate)	$ (6,551)	$ 8,191
Provision for earnings sharing	(2,392)	(2,767)
Idaho		
Decoupling surcharge (rebate)	$ (1,641)	$ 2,206
Oregon		
Decoupling surcharge (rebate)	$ (3,182)	$ 1,912

Total natural gas revenues increased $3.8 million for 2017 as compared to 2016, primarily reflecting the following:

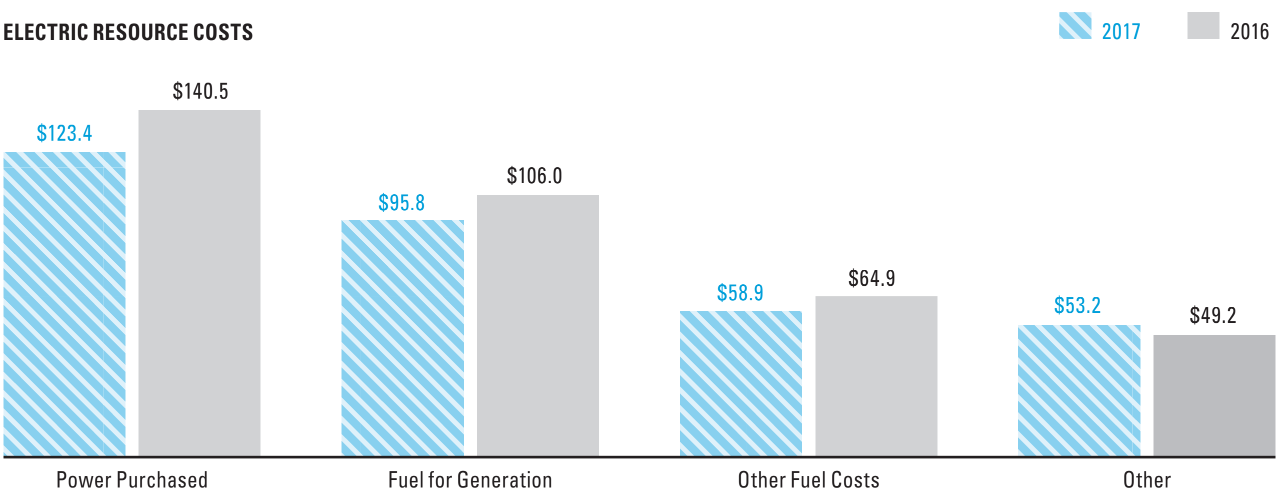
- a $36.3 million increase in retail natural gas revenues due to an increase in volumes (increased revenues $51.2 million), partially offset by lower retail rates (decreased revenues $14.9 million).
  - We sold more retail natural gas in 2017 as compared to 2016 primarily due to cooler weather in the first and fourth quarters, as well as customer growth. Compared to 2016, residential use per customer increased 16 percent and commercial use per customer increased 17 percent. Heating degree days in Spokane were 3 percent above normal for 2017, and 17 percent above 2016. Heating degree days in Medford were 1 percent below normal for 2017, and 17 percent above 2016.
  - Lower retail rates were due to PGAs, partially offset by a general rate increase in Oregon.
- a $10.7 million decrease in wholesale natural gas revenues due to a decrease in volumes (decreased revenues $36.4 million), partially offset by an increase in prices (increased revenues $25.7 million). In 2017, $49.3 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In 2016, $51.2 million of these sales were made to our electric generation operations. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.
- a $23.7 million decrease in natural gas revenue due to decoupling. Weather was overall cooler than normal during the heating season in 2017, which resulted in decoupling rebates. Weather was warmer than normal during the heating season in 2016, which resulted in decoupling surcharges. Decoupling mechanisms are not impacted by fluctuations in weather compared to prior year; rather, they are only impacted by weather fluctuations as compared to normal weather.

The following table presents Avista Utilities' average number of electric and natural gas retail customers for the years ended December 31:

	Electric Customers		Natural Gas Customers	
	2017	2016	2017	2016
Residential	334,848	330,699	307,375	300,883
Commercial	42,154	41,785	35,192	34,868
Interruptible	—	—	37	37
Industrial	1,328	1,342	251	255
Public street and highway lighting	569	558	—	—
Total retail customers	378,899	374,384	342,855	336,043

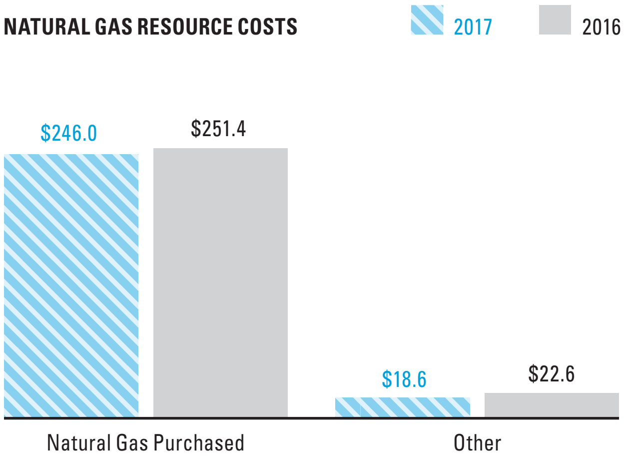
The following graphs present Avista Utilities' resource costs for the years ended December 31 (dollars in millions):

ELECTRIC RESOURCE COSTS



Total electric resource costs in the graph above include intracompany resource costs of $49.3 million and $51.2 million for 2017 and 2016, respectively.

NATURAL GAS RESOURCE COSTS



Total natural gas resource costs in the graphs above include intracompany resource costs of $35.3 million and $44.0 million for 2017 and 2016, respectively.

Total electric resource costs decreased $29.3 million for 2017 as compared to 2016 primarily reflecting the following:

- a $17.1 million decrease in power purchased due to a decrease in wholesale prices (decreased costs $22.5 million), partially offset by an increase in the volume of power purchases (increased costs $5.4 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $10.2 million decrease in fuel for generation primarily due to a decrease in thermal generation (due in part to increased hydroelectric generation) as well as a decrease in fuel prices.
- a $6.0 million decrease in other fuel costs.
- a $1.5 million increase from amortizations and deferrals of power costs.
- a $0.5 million decrease in other electric resource costs.
- a $3.0 million increase in other regulatory amortizations.

Total natural gas resource costs decreased $9.4 million for 2017 as compared to 2016 primarily reflecting the following:

- a $5.4 million decrease in natural gas purchased due to a decrease in total therms purchased (decreased costs $22.1 million), partially offset by an increase in the price of natural gas (increased costs $16.7 million). Total therms purchased decreased due to a decrease in wholesale sales, partially offset by an increase in retail sales.
- a $6.6 million decrease from amortizations and deferrals of natural gas costs.
- a $2.6 million increase in other regulatory amortizations.

2016 Compared to 2015

The following table presents Avista Utilities' operating revenues, resource costs and resulting gross margin for the years ended December 31 (dollars in millions):

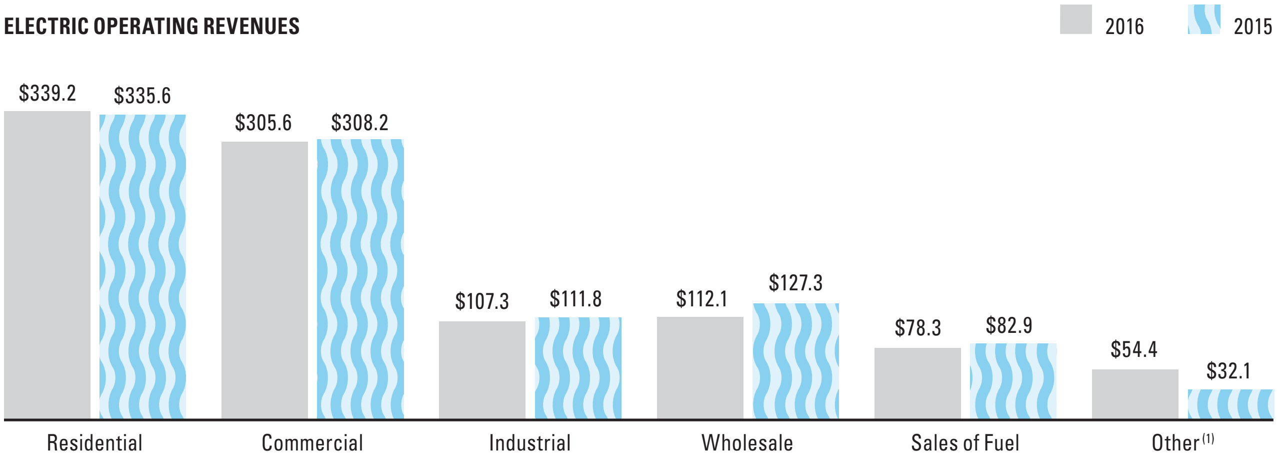
	Electric		Natural Gas		Intracompany		Total	
	2016	2015	2016	2015	2016	2015	2016	2015
Operating revenues	$ 996,959	$ 997,873	$ 470,894	$ 521,010	$ (95,215)	$ (107,020)	$ 1,372,638	$ 1,411,863
Resource costs	360,591	400,910	273,976	351,101	(95,215)	(107,020)	539,352	644,991
Gross margin	$ 636,368	$ 596,963	$ 196,918	$ 169,909	$ —	$ —	$ 833,286	$ 766,872

The gross margin on electric sales increased $39.4 million and the gross margin on natural gas sales increased $27.0 million. The increase in electric gross margin was primarily due to general rate increases, lower resource costs, the implementation of decoupling in Idaho and a $6.6 million decrease in the provision for earnings sharing (which is an offset to revenue), partially offset by lower electric loads. For 2016, we recognized a pre-tax benefit of $5.1 million under the ERM in Washington compared to a benefit of $6.3 million for 2015.

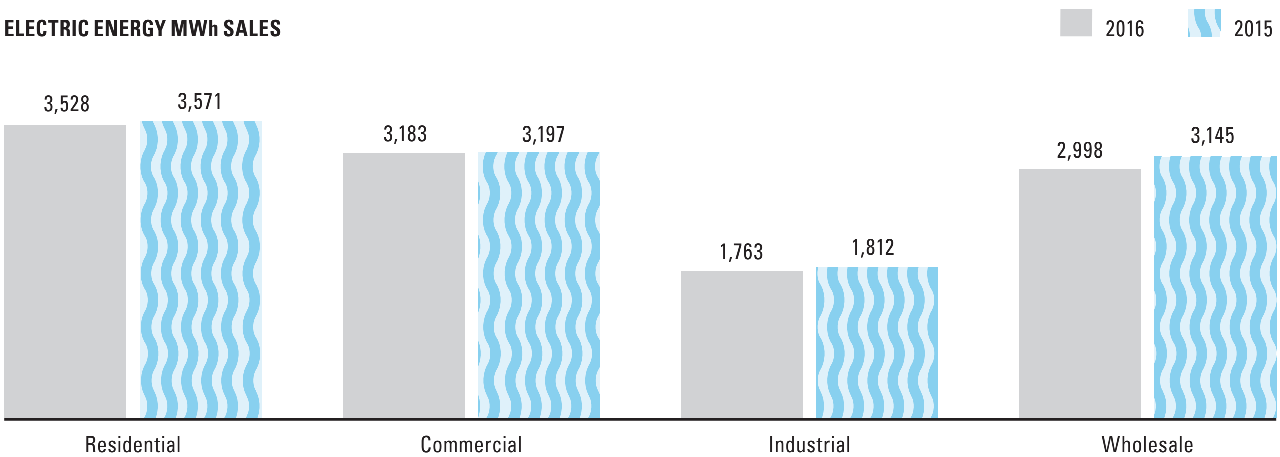
The increase in natural gas gross margin was primarily due to general rate increases in each of our jurisdictions, lower natural gas resources costs, the implementation of decoupling mechanisms in Idaho and Oregon, and higher natural gas retail loads.

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

The following graphs present Avista Utilities' electric operating revenues and megawatt-hour (MWh) sales for the years ended December 31 (dollars in millions and MWhs in thousands):



(1) *This balance includes public street and highway lighting, which is considered part of retail electric revenues and it also includes revenues and rebates from decoupling.*



The following table presents Avista Utilities' decoupling and customer earnings sharing mechanisms by jurisdiction that are included in utility electric operating revenues for the years ended December 31 (dollars in thousands):

	Electric Operating Revenues	
	2016	2015
Washington		
Decoupling surcharge	$ 11,324	$ 4,740
Provision for earnings sharing [1]	221	(3,423)
Idaho		
Decoupling surcharge	$ 6,025	N/A
Provision for earnings sharing [2]	711	(2,198)

(1) *The provision for earnings sharing in Washington in 2016 resulted from a $2.5 million reduction in the 2015 provision for earnings sharing (which increased 2016 revenues) offset by a $2.3 million provision for earnings sharing for 2016 electric operations.*

(2) *The provision for earnings sharing in Idaho in 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.*

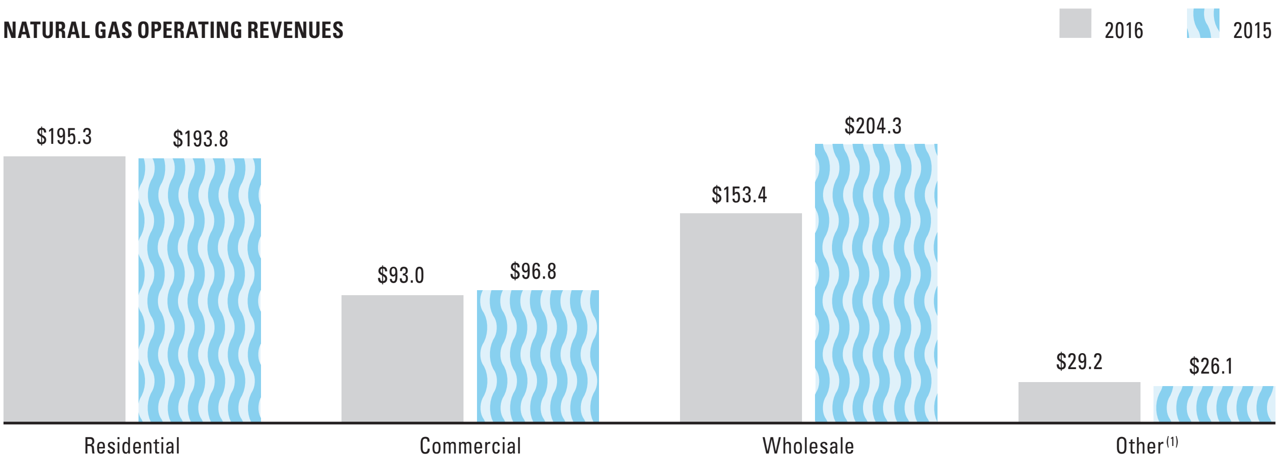
Total electric revenues decreased $0.9 million for 2016 as compared to 2015, primarily reflecting the following:

- a $3.0 million decrease in retail electric revenues due to a decrease in total MWhs sold (decreased revenues $9.5 million), partially offset by an increase in revenue per MWh (increased revenues $6.5 million).
  - The increase in revenue per MWh was primarily due to a general rate increase in Idaho and the expiration of the ERM rebate to customers 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 electric heating loads), warmer in April and May (lower electric heating loads), cooler June through August (lower electric cooling loads) and cooler in the fourth quarter (higher electric heating loads) as compared to the prior year (which overall decreased electric loads). Compared to 2015, residential electric use per customer decreased 1 percent and commercial use per customer decreased 1 percent. Heating degree days in Spokane were 13 percent below normal and 3 percent above 2015. The impact from increased heating loads was offset by decreased cooling loads in the summer. 2016 cooling degree days were 13 percent below normal and 41 percent below the

- prior year. The overall decrease in use per customer was partially offset by growth in the number of customers.
- a $15.2 million decrease in wholesale electric revenues due to a decrease in sales volumes (decreased revenues $5.5 million) and a decrease in sales prices (decreased revenues $9.7 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $4.6 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 2016, $44.0 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For 2015, $50.0 million of these sales were made to our natural gas operations.
- a $12.6 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 in 2016 as compared to 2015.
- a $6.6 million decrease in the electric provision for earnings sharing (which increases revenues) 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. For 2016 electric operations, we recorded a $2.3 million provision for earnings sharing.

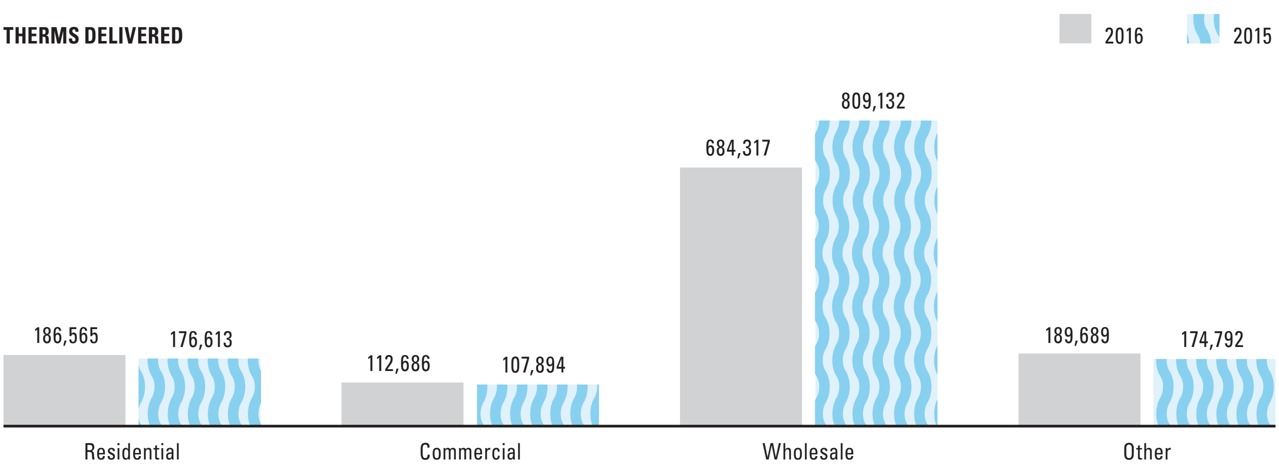
The following graphs present Avista Utilities' natural gas operating revenues and therms delivered for the years ended December 31 (dollars in millions and therms in thousands):

NATURAL GAS OPERATING REVENUES



(1) This balance includes interruptible and industrial revenues, which are considered part of retail natural gas revenues and it also includes revenues and rebates from decoupling.

THERMS DELIVERED



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 years ended December 31 (dollars in thousands):

	Natural Gas Operating Revenues	
	2016	2015
Washington		
Decoupling surcharge	$ 8,191	$ 6,004
Provision for earnings sharing	(2,767)	—
Idaho		
Decoupling surcharge	$ 2,206	N/A
Oregon		
Decoupling surcharge	$ 1,912	N/A

(N/A) This mechanism did not exist during this time period.

Total natural gas revenues decreased $50.1 million for 2016 as compared to 2015 primarily reflecting the following:

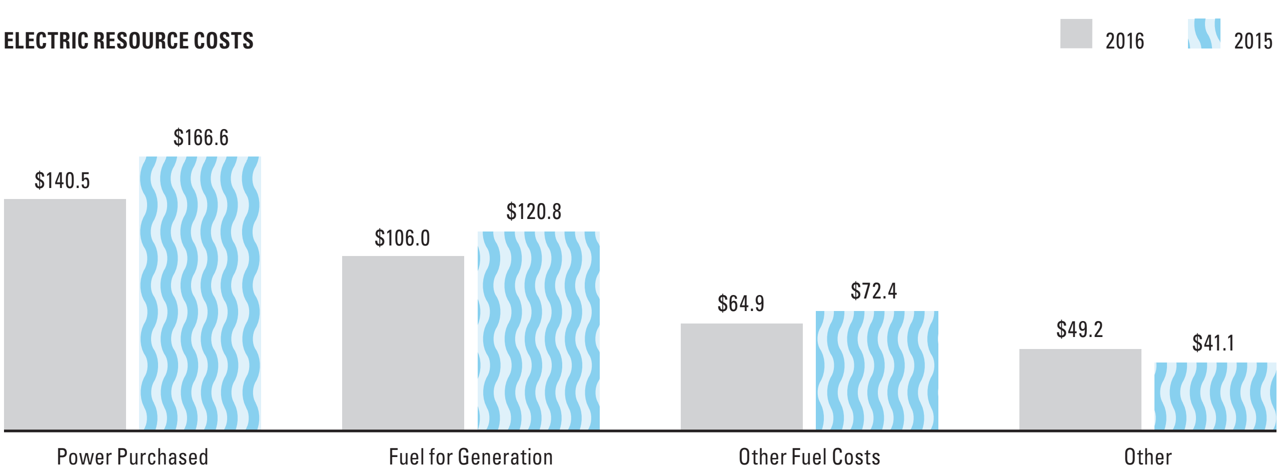
- a $3.4 million decrease in retail natural gas revenues due to lower retail rates (decreased revenues $18.4 million), partially offset by an increase in volumes (increased revenues $15.0 million).
  - Lower retail rates were due to PGAs, which passed through lower costs of natural gas, partially offset by general rate increases.
  - We sold more retail natural gas in 2016 as compared to 2015 primarily due to cooler weather in the first and fourth quarters, as well as customer growth. Compared to 2015, residential use per customer increased 5 percent and commercial use per customer increased 3 percent. Heating degree days in Spokane were 13 percent below historical average for 2016, and 3 percent above 2015. Heating degree days in Medford were 16 percent below historical average for 2016, and 3 percent above 2015.
- a $50.8 million decrease in wholesale natural gas revenues due to a decrease in prices (decreased revenues $22.8 million) and a decrease in volumes (decreased revenues $28.0 million). In 2016, $51.2 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In 2015, $57.0 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 $6.3 million increase in natural gas revenues due to decoupling, which reflected the implementation of decoupling mechanisms in Idaho and Oregon, as well as an increase in the decoupling surcharge in Washington.
- a $2.8 million increase in the provision for earnings sharing (which decreases revenues) representing the 2016 provision for Washington natural gas operations.

The following table presents Avista Utilities' average number of electric and natural gas retail customers for the years ended December 31:

	Electric Customers		Natural Gas Customers	
	2016	2015	2016	2015
Residential	330,699	327,057	300,883	296,005
Commercial	41,785	41,296	34,868	34,229
Interruptible	—	—	37	35
Industrial	1,342	1,353	255	261
Public street and highway lighting	558	529	—	—
Total retail customers	374,384	370,235	336,043	330,530

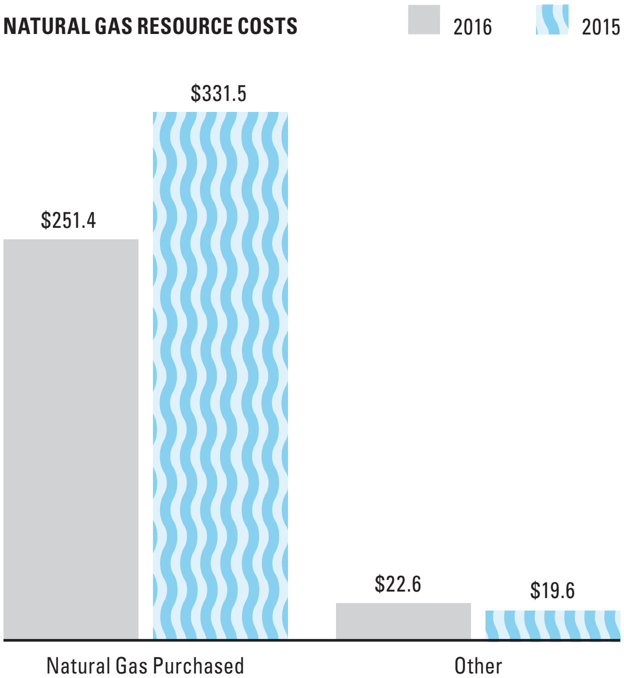
The following graphs present Avista Utilities' resource costs for the years ended December 31 (dollars in millions):

ELECTRIC RESOURCE COSTS



Total electric resource costs in the graph above include intracompany resource costs of $51.2 million and $57.0 million for 2016 and 2015, respectively.

NATURAL GAS RESOURCE COSTS



Total natural gas resource costs in the graphs above include intracompany resource costs of $44.0 million and $50.0 million for 2016 and 2015, respectively.

Total electric resource costs decreased $40.3 million for 2016 as compared to 2015 primarily reflecting the following:

- a $26.1 million decrease in power purchased due to a decrease in the volume of power purchases (decreased costs $9.3 million) and a decrease in wholesale prices (decreased costs $16.8 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $14.8 million decrease in fuel for generation primarily due to a decrease in thermal generation (due in part to increased hydroelectric generation) and a decrease in natural gas fuel prices.
- a $7.5 million decrease in other fuel costs.
- a $3.0 million decrease from amortizations and deferrals of power costs.
- a $5.6 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 $5.4 million increase in other regulatory amortizations.

Total natural gas resource costs decreased $77.1 million for 2016 as compared to 2015 primarily reflecting the following:

- an $80.1 million decrease in natural gas purchased due to a decrease in the price of natural gas (decreased costs $52.6 million) and a decrease in total therms purchased (decreased costs $27.5 million). Total therms purchased decreased due to a decrease in wholesale sales, partially offset by an increase in retail sales.
- a $1.6 million decrease 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, as well as current rebates to customers through PGAs.
- a $4.6 million increase in other regulatory amortizations.

RESULTS OF OPERATIONS—ALASKA ELECTRIC LIGHT AND POWER COMPANY

2017 Compared to 2016

Net income for AEL&P was $9.1 million for the year ended December 31, 2017, compared to $8.0 million for 2016.

The following table presents AEL&P's operating revenues, resource costs and resulting gross margin for the years ended December 31 (dollars in millions):

	Electric	
	2017	**2016**
Operating revenues	$ 53,027	$ 46,276
Resource costs	13,403	12,014
Gross margin	$ 39,624	$ 34,262

In 2017, there was an increase in electric gross margin which was primarily related to a general rate increase, effective in November 2016, and increases in electric heating loads due to weather that was cooler than the prior year. There were also slight increases in residential and commercial customers. This was partially offset by an increase in resource costs primarily due to purchased power and the general rate case settlement.

An increase in resource costs of $1.0 million related to a settlement agreement for AEL&P's 2016 electric general rate case is included in electric gross margin for 2017. See "Regulatory Matters" for further discussion of the settlement agreement. The increase in electric gross margin was partially offset by an increase in operating expenses and a decrease in equity-related AFUDC due to the construction of an additional back-up generation plant completed in 2016.

While the cooler weather did have some effect on AEL&P revenues during 2017, 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.

Operating expenses increased primarily due to supplies expense for the new back-up generation plant, which went into service in the fourth quarter of 2016.

2016 Compared to 2015

Net income for AEL&P was $8.0 million for the year ended December 31, 2016, compared to $6.6 million for 2015. The increase in earnings for 2016 was primarily due to an increase in electric gross margin and an increase in equity-related AFUDC (increased earnings) due to the construction of an additional back-up generation plant which was completed during the fourth quarter of 2016.

The following table presents AEL&P's operating revenues, resource costs and resulting gross margin for the years ended December 31 (dollars in millions):

	Electric	
	2016	2015
Operating revenues	$ 46,276	$ 44,778
Resource costs	12,014	11,973
Gross margin	$ 34,262	$ 32,805

The increase in electric gross margin was primarily related to a decrease in 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 interim rate increase effective in November 2016. These were partially offset by a slight decrease in sales volumes to commercial and government customers and an increase in other resource costs.

RESULTS OF OPERATIONS—ECOVA—DISCONTINUED OPERATIONS

Ecova was disposed of as of June 30, 2014. As a result, in accordance with GAAP, all of Ecova's operating results were removed from each line item on the Consolidated Statements of Income and reclassified into discontinued operations for all periods presented.

2017 and 2016 Compared to 2015

There was zero net income or loss for 2017 and 2016. Ecova's net income was $5.1 million for 2015. The net income for 2015 was primarily related to a tax benefit during 2015 that resulted from the reversal of a valuation allowance against net operating losses at Ecova because the net operating losses were deemed realizable under the current tax code.

RESULTS OF OPERATIONS—OTHER BUSINESSES

2017 Compared to 2016

The net loss from these operations was $7.9 million for 2017 compared to a net loss of $3.2 million for 2016. Net losses for 2017 were partially related to federal income tax law changes, which resulted in the revaluing of net deferred income tax assets to reflect the reduction in the corporate income tax rate from 35 percent to 21 percent, causing a non-cash increase in income tax expense. Also, there were renovation expenses and increased compliance costs at one of our subsidiaries, the recognition of our portion of net losses from our equity investments, corporate costs (including costs associated with exploring strategic opportunities) and impairment charges associated with two of our equity investments.

2016 Compared to 2015

The net loss from these operations was $3.2 million for 2016 compared to a net loss of $1.9 million for 2015. Net losses for 2016 were primarily related to an increase in losses on investments due to initial organization costs and management fees associated with a new investment, as well as an impairment recorded on a building we own. This was partially offset by a slight decrease in corporate costs (including costs associated with exploring strategic opportunities) and a slight increase in net income at METALfx.

ACCOUNTING STANDARDS TO BE ADOPTED IN 2018

At this time, we are not expecting the adoption of accounting standards to have a material impact on our financial condition, results of operations and cash flows in 2018. For information on accounting standards adopted in 2017 and accounting standards expected to be adopted in future periods, see "Note 2 of the Notes to Consolidated Financial Statements."

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

- **Regulatory accounting**, which requires that certain costs and/or obligations be reflected as deferred charges on our Consolidated Balance Sheets and are not reflected in our Consolidated Statements of Income until the period during which matching revenues are recognized. We also have decoupling revenue deferrals. As opposed to cost deferrals which are not recognized in the Consolidated Statements of Income until they are included in rates, decoupling revenue is recognized in the Consolidated Statements of Income during the period in which it occurs (i.e. during the period of revenue shortfall or excess due to fluctuations in customer usage), subject to certain limitations, and a regulatory asset/liability is established which will be surcharged or rebated to customers in future periods. GAAP requires that for any alternative revenue program, like decoupling, the revenue must be expected to be collected from customers within 24 months of the deferral to qualify for recognition in the current period. Any amounts included in the Company's decoupling program that are not expected to be collected from customers within 24 months are not recorded in the financial statements until the period in which revenue recognition criteria are met. This could ultimately result in more decoupling revenue being collected from customers over the life of the decoupling program than what is deferred and recognized in the current period financial statements. We make estimates regarding the amount of revenue that will be collected within 24 months of deferral. We also make the assumption that there are regulatory precedents for many of our regulatory items and that we will be allowed recovery of these costs via retail rates in future periods. If we were no longer allowed to apply regulatory accounting or no longer allowed recovery of these costs, we could be required to recognize significant write-offs of regulatory assets and liabilities in the Consolidated Statements of Income. See "Notes 1 and 20 of the Notes to Consolidated Financial Statements" for further discussion of our regulatory accounting policy and mechanisms.

In addition to the above, while accounting for income taxes is not a critical policy or estimate, the interpretation of the TCJA requires many judgments, and the regulatory treatment of the changes in deferred income tax assets and liabilities (excess deferred taxes) resulting from the TCJA does involve certain regulatory assumptions and calculations for determining the amortization period over which to return excess deferred taxes to customers. For instance, excess deferred taxes associated with utility plant items will be returned to customers using the ARAM, which is a prescribed calculation. However, there is not clear guidance on how or when to return excess deferred taxes for non-plant items. We do not currently have an estimate for the amortization period of the non-plant items as we are waiting for additional implementation guidance from various regulatory agencies. If new guidance were to be issued regarding how to return excess deferred taxes to customers, it could significantly impact our financial results and future cash flows. See the "Executive Level Summary" for additional discussion of the federal income tax law changes.

- **Utility energy commodity derivative asset and liability accounting**, where we estimate the fair value of outstanding commodity derivatives and we offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. This accounting treatment is supported by accounting orders issued by the WUTC and the IPUC. If we were no longer allowed to apply regulatory accounting or no longer allowed recovery of these costs, we could be required to recognize significant changes in fair value of these energy commodity derivatives on a regular basis in the Consolidated Statements of Income, which could lead to significant fluctuations in net income. See "Notes 1 and 6 of the Notes to Consolidated Financial Statements" for further discussion of our energy commodity derivative accounting policy and amounts recorded in the financial statements.
- **Interest rate swap derivative asset and liability accounting**, where we estimate the fair value of outstanding interest rate swap derivatives, and U.S. Treasury lock agreements and offset the derivative asset or liability with a regulatory asset or liability. This is similar to the treatment of energy commodity derivatives described above. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt.

  During the fourth quarter of 2017, WUTC Staff and other parties to our 2017 electric and natural gas general rate cases filed their testimony in which the WUTC Staff recommended the exclusion of the Washington portion of our 2016 settled interest rate swaps. The total amount of the 2016 settled interest rate swaps was $54.0 million, with approximately 60 percent of this total being allocated to Washington.

  If recovery of the 2016 settled interest rate swap payments is not approved by the WUTC, this could change our current conclusion that settlement payments related to the 2017 settled interest rate swaps and the unsettled interest rate swaps are probable of recovery through rates. If we concluded that recovery of these swap related payments were no longer probable, we may be required to derecognize the related regulatory assets and liabilities and we could be required to recognize significant changes in fair value or settlements of these interest rate swap derivatives on a regular basis in the Consolidated Statements of Income, which could lead to significant fluctuations in net income.

  See "Regulatory Matters—Washington General Rate Cases" for further discussion of this matter.
- **Pension Plans and Other Postretirement Benefit Plans**, discussed in further detail below.
- **Contingencies**, related to unresolved regulatory, legal and tax issues for which there is inherent uncertainty for the ultimate outcome of the respective matter. We accrue a loss contingency if it is probable that an asset is impaired or a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. We also disclose losses that do not meet these conditions for accrual, if there is a reasonable possibility that a potential loss may be incurred. For all material contingencies, we have made a judgment as to the probability of a loss occurring and as to whether or not the amount of the loss can be reasonably estimated. If the loss recognition criteria are met, liabilities are accrued or assets are reduced. However, no assurance can be given to the ultimate outcome of any particular contingency. See "Notes 1 and 19 of the Notes to Consolidated Financial Statements" for further discussion of our commitments and contingencies.

Pension Plans and Other Postretirement Benefit Plans—Avista Utilities

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

The Finance Committee of the Board of Directors approves investment policies, objectives and strategies that seek an appropriate return for the pension plan and it reviews and approves changes to the investment and funding policies.

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

Our pension plan assets are invested in debt securities and mutual funds, trusts and partnerships that hold marketable debt and equity securities, real estate and absolute return funds. In seeking to obtain a return that aligns with the funded status of the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee. The Finance Committee has established target investment allocation percentages by asset classes and also investment ranges for each asset class. The target investment allocation percentages are typically the midpoint of the established range. See "Note 10 of the Notes to Consolidated Financial Statements" for the target investment allocation percentages.

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

Pension costs (including the SERP) were $26.5 million for 2017, $26.8 million for 2016 and $27.1 million for 2015. Of our pension costs, approximately 60 percent are expensed and 40 percent are capitalized consistent with labor charges. The costs related to the SERP are expensed. Our costs for the pension plan are determined in part by actuarial formulas that are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension costs are affected by among other things:

- employee demographics (including age, compensation and length of service by employees),
- the amount of cash contributions we make to the pension plan,
- the actual return on pension plan assets,
- expected return on pension plan assets,
- discount rate used in determining the projected benefit obligation and pension costs,
- assumed rate of increase in employee compensation,
- life expectancy of participants and other beneficiaries, and
- expected method of payment (lump sum or annuity) of pension benefits.

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

We revise the key assumption of the discount rate each year. In selecting a discount rate, we consider yield rates at the end of the year for highly rated corporate bond portfolios with cash flows from interest and maturities similar to that of the expected payout of pension benefits.

The expected long-term rate of return on plan assets is reset or confirmed annually based on past performance and economic forecasts for the types of investments held by our plan.

The following chart reflects the assumptions used each year for the pension discount rate (exclusive of the SERP), the expected long-term return on plan assets and the actual return on plan assets and their impacts to the pension plan associated with the change in assumption (dollars in millions):

	2017	2016	2015
Discount rate			
Pension discount rate (exclusive of SERP)	3.71%	4.26%	4.58%
Increase/(decrease) to projected benefit obligation (exclusive of SERP)	$ 49.2	$ 27.7	$ (31.0)
Return on plan assets			
Expected long-term return on plan assets	5.87%	5.40%	5.30%
Increase/(decrease) to pension costs	$ (2.5)	$ (0.5)	$ 6.9
Actual return on plan assets—net of fees	15.60%	8.10%	(0.80)%
Actual gain/(loss) on plan assets	$ 82.5	$ 43.2	$ (4.3)

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

Actuarial Assumption	Change in Assumption	Effect on Projected Benefit Obligation	Effect on Pension Cost
Expected long-term return on plan assets	(0.5)%	$ —*	$ 2.7
Expected long-term return on plan assets	0.5%	—*	(2.7)
Discount rate	(0.5)%	50.6	4.4
Discount rate	0.5%	(44.9)	(3.9)

* *Changes in the expected return on plan assets would not affect our projected benefit obligation.*

We provide certain health care and life insurance benefits for substantially all of our retired employees. We accrue the estimated cost of postretirement benefit obligations during the years that employees provide service. Assumed health care cost trend rates have a significant effect on the amounts reported for our postretirement plans. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase our accumulated postretirement benefit obligation as of December 31, 2017 by $6.6 million and the service and interest cost by $0.8 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease our accumulated postretirement benefit obligation as of December 31, 2017 by $5.2 million and the service and interest cost by $0.6 million.

Liquidity and Capital Resources

OVERALL LIQUIDITY

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

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

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

We periodically file for rate adjustments for recovery of operating costs and capital investments and to seek the opportunity to earn reasonable returns as allowed by regulators.

Avista Utilities has regulatory mechanisms in place that provide for the deferral and recovery of the majority of power and natural gas supply costs. However, when power and natural gas costs exceed the levels currently recovered from retail customers, net cash flows are negatively affected. Factors that could cause purchased power and natural gas costs to exceed the levels currently recovered from our customers include, but are not limited to, higher prices in wholesale markets when we buy energy or an increased need to purchase power in the wholesale markets, and a lack of regulatory approval for higher authorized net power supply costs through general rate case decisions. Factors beyond our control that could result in an increased need to purchase power in the wholesale markets include, but are not limited to:

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

In addition to the above, Avista Utilities enters into derivative instruments to hedge our exposure to certain risks, including fluctuations in commodity market prices, foreign exchange rates and interest rates (for purposes of issuing long-term debt in the future). These derivative instruments often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement, in the event of a downgrade in the Company's credit ratings or changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against the Company's credit facilities and cash. See "Enterprise Risk Management—Demands for Collateral" below.

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

As of December 31, 2017, we had $260.6 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 CONSOLIDATED CASH FLOW STATEMENT

Overall

During 2017, cash flows from operating activities were $410.3 million, proceeds from the issuance of long-term debt were $90.0 million and we received $56.4 million from the issuance of common stock. Cash requirements included utility capital expenditures of $412.3 million, the repayment of borrowings under our committed line of credit of $15.0 million, dividends of $92.5 million and net cash paid for the settlement of interest rate swap derivatives of $8.8 million.

2017 Compared to 2016

Consolidated Operating Activities

Net cash provided by operating activities was $410.3 million for 2017 compared to $358.3 million for 2016. The increase in net cash provided by operating activities was due in part to income tax refund claims in 2017 related to 2014 and 2015 tax years to utilize net operating losses and investment tax credits. We received an income tax refund of approximately $41.7 million during the fourth quarter of 2017 compared to an increase in income tax receivables of $33.9 million in 2016. In addition, during 2017 our net payments for the settlement of outstanding interest rate swaps decreased by $45.1 million, from $54.0 million in 2016 to $8.8 million for 2017.

The increases above were partially offset by an increase in pension contributions from $12.0 million in 2016 to $22.0 million in 2017 and an increase in collateral posted for derivative instruments of $22.4 million in 2017, compared to a decrease in collateral posted of $10.7 million in 2016. The increase in collateral posted during 2017 was due to a decrease in the fair value of energy commodity derivatives which required additional collateral. In addition, most of our energy commodity derivatives are transacted on clearinghouse exchanges, which require initial margin collateral and additional cash collateral when derivatives are in liability positions.

Consolidated Investing Activities

Net cash used in investing activities was $434.1 million for 2017, an increase compared to $432.5 million for 2016. During 2017, we paid $412.3 million for utility capital expenditures, compared to $406.6 million for 2016. In addition, during 2017, our subsidiaries disbursed net cash of $15.5 million for notes receivable to third parties, equity investments and property investments, compared to $18.2 million in 2016.

Consolidated Financing Activities

Net cash provided by financing activities was $31.5 million for 2017 compared to net cash provided of $72.2 million for 2016. In 2017 we had the following significant transactions:

- issuance and sale of $90.0 million of Avista Corp. first mortgage bonds in December 2017, the proceeds of which were used to pay down a portion of our committed line of credit,
- payment of $3.3 million for the maturity of long-term debt,
- increase in cash dividends paid to $92.5 million (or $1.43 per share) for 2017 from $87.2 million (or $1.37 per share) for 2016,
- $15.0 million net decrease in the balance of our committed line of credit, and
- issuance of $56.4 million of common stock (net of issuance costs).

2016 Compared to 2015

Consolidated Operating Activities

Net cash provided by operating activities was $358.3 million for 2016 compared to $375.6 million for 2015. The decrease in net cash provided by operating activities was primarily related to the cash settlement of interest rate swap derivatives in the third quarter of 2016 totaling $54.0 million. The interest rate swap derivatives were settled in connection with the pricing of first mortgage bonds that were issued in December 2016. In addition, our accounts receivable balances increased during 2016 (which reduces operating cash flow), due to higher sales during the fourth quarter of 2016 due to colder weather as compared to the fourth quarter of 2015 and due to the timing of collections.

There was a decrease in collateral posted for derivative instruments in 2016 (primarily due to an increase in the fair value of outstanding energy commodity derivatives, which required less collateral) as compared to an increase in collateral posted during 2015.

Pension contributions were $12.0 million for both 2016 and 2015.

Net cash received from income tax refunds increased to $13.5 million for 2016 compared to $10.0 million for 2015. In addition, the income tax receivable increased $33.9 million in 2016. We were in a refund position as of December 31, 2016 with regards to income taxes because the Company generated a net operating loss for tax purposes in 2016 primarily due to bonus depreciation on utility plant placed in service during the year and the settlement of interest rate swaps. The Company carried back the net operating loss against prior year tax returns and fully utilized the net operating loss through the carryback. Additionally, the Company generated $19.4 million of federal investment income tax credits in 2016; $9.6 million of which was carried back against a prior tax return with the remaining $9.8 million to be carried forward to future federal tax periods.

The provision for deferred income taxes was $124.5 million for 2016, compared to $51.8 million for 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 capital projects, deferred taxes on the decoupling regulatory assets and deferred taxes on interest rate swap derivatives.

Consolidated Investing Activities

Net cash used in investing activities was $432.5 million for 2016, an increase compared to $387.8 million for 2015. During 2016, we paid $406.6 million for utility capital expenditures, compared to $393.4 million for 2015. In addition, during 2016, our subsidiaries disbursed $10.1 million for notes receivable to third parties and received $5.0 million in repayments on these notes receivable. Our subsidiaries also made $7.8 million in investments and purchased buildings and other property as investments for $5.3 million.

During 2015, we received cash proceeds (related to the settlement of the escrow accounts) of $13.9 million from the sale of Ecova.

Consolidated Financing Activities

Net cash provided by financing activities was $72.2 million for 2016 compared to net cash provided of $0.5 million for 2015. In 2016 we had the following significant transactions:

- borrowing of $70.0 million pursuant to a term loan agreement in August, which was used to repay a portion of the $90.0 million in first mortgage bonds that matured in August 2016,
- issuance and sale of $175.0 million of Avista Corp. first mortgage bonds in December 2016, the proceeds of which were used to repay the $70.0 million term loan, with the remainder being used to pay down a portion of our committed line of credit,
- payment of $163.2 million for the maturity of long-term debt (including the $70.0 million term loan),
- increase in cash dividends paid to $87.2 million (or $1.37 per share) for 2016 from $82.4 million (or $1.32 per share) for 2015,
- $15.0 million net increase in the balance of our committed line of credit, and
- issuance of $67.0 million of common stock (net of issuance costs).

In 2015 we had the following significant transactions:

- issuance and sale of $100.0 million of Avista Corp. first mortgage bonds in December 2015,
- payment of $2.9 million for the maturity of long-term debt,
- cash dividends paid were $82.4 million (or $1.32 per share) for 2015,
- issuance of $1.6 million of common stock (net of issuance costs), and
- repurchase of $2.9 million of our 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 December 31, 2017 and 2016 (dollars in thousands):

	December 31, 2017		December 31, 2016	
	Amount	Percent of Total	Amount	Percent of Total
Current portion of long-term debt and capital leases	$ 277,438	7.6%	$ 3,287	0.1%
Short-term borrowings	105,398	2.9%	120,000	3.4%
Long-term debt to affiliated trusts	51,547	1.4%	51,547	1.5%
Long-term debt and capital leases	1,491,799	40.8%	1,678,717	47.9%
Total debt	1,926,182	52.7%	1,853,551	52.9%
Total Avista Corporation shareholders' equity	1,729,828	47.3%	1,648,727	47.1%
Total	$ 3,656,010	100.0%	$ 3,502,278	100.0%

Our shareholders' equity increased $81.1 million during 2017 primarily due to net income, the issuance of common stock and stock compensation net of minimum tax withholdings, 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.

Committed Lines of Credit

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million that expires in April 2021. As of December 31, 2017, we had $260.6 million of available liquidity under this line of credit.

The Avista Corp. credit facility contains customary covenants and default provisions, including a covenant which does not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 65 percent at any time. As of December 31, 2017, we were in compliance with this covenant with a ratio of 52.7 percent.

AEL&P has a $25.0 million committed line of credit that expires in November 2019. As of December 31, 2017, there were no borrowings or letters of credit outstanding under this credit facility.

The AEL&P credit facility contains customary covenants and default provisions including a covenant which does not permit the ratio of "consolidated total debt at AEL&P" to "consolidated total capitalization at AEL&P," (including the impact of the Snettisham obligation) to be greater than 67.5 percent at any time. As of December 31, 2017, AEL&P was in compliance with this covenant with a ratio of 53.7 percent.

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 year ended December 31 (dollars in thousands):

	2017	2016	2015
Balance outstanding at end of year	$ 105,000	$ 120,000	$ 105,000
Letters of credit outstanding at end of year	$ 34,420	$ 34,353	$ 44,595
Maximum balance outstanding during the year	$ 254,500	$ 280,000	$ 180,000
Average balance outstanding during the year	$ 133,027	$ 171,090	$ 95,573
Average interest rate during the year	1.88%	1.26%	0.98%
Average interest rate at end of year	2.26%	1.50%	1.18%

As of December 31, 2017, 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.

Long-Term Debt Borrowings

In December 2017, we issued and sold $90.0 million of 3.91 percent first mortgage bonds due in 2047 pursuant to a bond purchase agreement with institutional investors in the private placement market. In connection with the pricing of the first mortgage bonds, the Company cash-settled five interest rate swap derivatives (notional aggregate amount of $60.0 million) and paid a net amount of $8.8 million, which will be amortized as a component of interest expense over the life of the debt. The effective interest rate of the first mortgage bonds is 4.55 percent, including the effects of the settled interest rate swap derivatives and issuance costs. We used the proceeds, less issuance costs, to repay a portion of the borrowings outstanding under our $400.0 million committed line of credit.

Equity Issuances

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. Through December 31, 2017, 2.7 million shares were issued under these agreements resulting in total net proceeds of $120.0 million, leaving 1.1 million shares remaining to be issued.

Other Transactions

During 2017, we filed income tax refund claims related to 2014 and 2015 to utilize net operating losses and investment tax credits and we received an income tax refund of approximately $41.7 million during the fourth quarter of 2017.

2018 Liquidity Expectations

During 2018, we expect to issue approximately $375.0 million of long-term debt and up to $85.0 million of equity in order to refinance maturing long-term debt, fund planned capital expenditures, fund the impacts of the federal income tax law changes and maintain an appropriate capital structure. The $85.0 million of equity in 2018 may come through the sale of shares through our sales agency agreements or from an equity contribution from Hydro One upon consummation of the acquisition or from a combination of those sources.

After considering the expected issuances of long-term debt and equity during 2018, 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.

2018 and Forward Operating Cash Flows

Due to federal income tax law changes, we expect our operating cash flows will be negatively impacted going forward primarily due to the loss of the bonus depreciation tax deduction and from the timing of the return of excess deferred taxes to customers. As a result, we may need to raise additional capital.

Limitations on Issuances of Preferred Stock and First Mortgage Bonds

We are restricted under our Restated Articles of Incorporation, as amended, as to the additional preferred stock we can issue. As of December 31, 2017, we could issue $1.3 billion of additional preferred stock at an assumed dividend rate of 6.0 percent. We are not planning to issue preferred stock.

Under the Avista Corp. and the AEL&P Mortgages and Deeds of Trust securing Avista Corp.'s and AEL&P's first mortgage bonds (including Secured Medium-Term Notes), respectively, each entity may issue additional first mortgage bonds in an aggregate principal amount equal to the sum of:

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

However, Avista Corp. and AEL&P may not individually issue any additional first mortgage bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the particular entity issuing the bonds has "net earnings" (as defined in the respective Mortgages) for any period of 12 consecutive calendar months out of the preceding 18 calendar months that were at least twice the annual interest requirements on that entity's mortgage securities at the time outstanding, including the first mortgage bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2017, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.3 billion in aggregate principal amount of additional first mortgage bonds at Avista Corp. and $24.1 million at AEL&P. We believe that we have adequate capacity to issue first mortgage bonds to meet our financing needs over the next several years.

CAPITAL EXPENDITURES

We are making capital investments in generation, transmission and distribution systems to preserve and enhance service reliability for our customers and replace aging infrastructure.

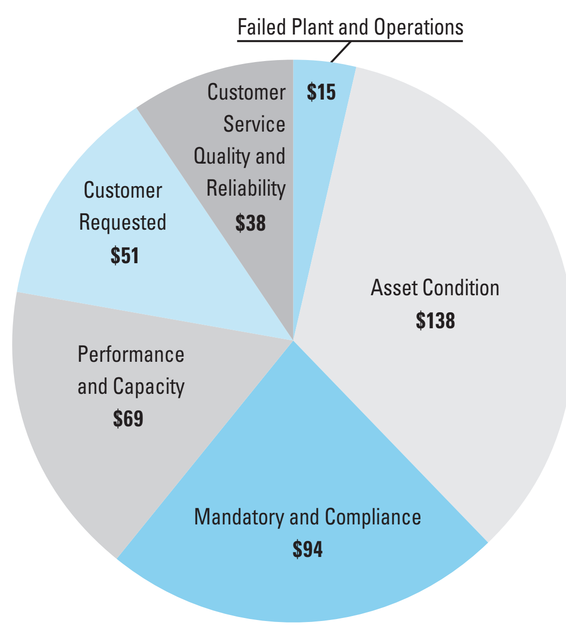
The following table summarizes our actual and expected capital expenditures as of and for the year ended December 31, 2017 (in thousands):

	Avista Utilities	AEL&P
2017 Actual capital expenditures		
Capital expenditures (per the Consolidated Statement of Cash Flows) [1]	$ 405,938	$ 6,401
Expected total annual capital expenditures (by year)		
2018	$ 405,000	$ 7,000
2019	405,000	8,000
2020	405,000	7,000

(1) Actual annual capital expenditures per the Consolidated Statement of Cash Flows may differ from our expected annual accrual-basis capital expenditures due to the timing of cash payments, the capital expenditure amounts accrued in accounts payable at the end of each period and the inclusion of AFUDC in our expected amounts, but excluded from the cash flow amounts.

The following graph shows Avista Utilities' capital budget for 2018:

CAPITAL BUDGET AT AVISTA UTILITIES FOR 2018 (DOLLARS IN MILLIONS)



For 2018, we changed our method of capital expenditure planning and tracking from breaking expenditures down by functional area (i.e. generation, transmission, distribution, information technology) to the primary investment reason behind our capital expenditure decisions. This tracking better aligns with how capital expenditure decisions are made and how they are submitted for regulatory recovery to the various state commissions.

These estimates of capital expenditures are subject to continuing review and adjustment. Actual capital expenditures may vary from our estimates due to factors such as changes in business conditions, construction schedules and environmental requirements.

OFF-BALANCE SHEET ARRANGEMENTS

As of December 31, 2017, we had $34.4 million in letters of credit outstanding under our $400.0 million committed line of credit, compared to $34.4 million as of December 31, 2016.

PENSION PLAN

We contributed $22.0 million to the pension plan in 2017. We expect to contribute a total of $110.0 million to the pension plan in the period 2018 through 2022, with an annual contribution of $22.0 million over that period.

The final determination of pension plan contributions for future periods is subject to multiple variables, most of which are beyond our control, including changes to the fair value of pension plan assets, changes in actuarial assumptions (in particular the discount rate used in determining the benefit obligation), or changes in federal legislation. We may change our pension plan contributions in the future depending on changes to any variables, including those listed above.

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

CREDIT RATINGS

Our access to capital markets and our cost of capital are directly affected by our credit ratings. In addition, many of our contracts for the purchase and sale of energy commodities contain terms dependent upon our credit ratings. See "Enterprise Risk Management—Credit Risk Liquidity Considerations" and "Note 6 of the Notes to Consolidated Financial Statements."

The following table summarizes our credit ratings as of February 20, 2018:

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

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

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

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

On December 22, 2017, the TCJA was signed into law. Although it is unclear when or how capital markets, credit rating agencies, the FERC or state public utility commissions may respond to this legislation, we expect that certain financial metrics used by credit rating agencies to evaluate the Company will be negatively impacted as a result of the TCJA. Also, we expect that our future cash flows from operations will be negatively impacted going forward. Further, there may be other material adverse effects resulting from the legislation that we have not yet identified. This has resulted in Moody's placing our credit ratings on negative outlook and could result in Moody's taking further negative action or other credit rating agencies taking similar action. These actions by the credit rating agencies may make it more difficult and costly for us to issue future debt securities and could increase borrowing costs under our credit facilities. See "Executive Level Summary" and "Note 11 of the Notes to Consolidated Financial Statements" for additional information regarding the TCJA and its impacts to Avista Corp.

DIVIDENDS

On February 2, 2018, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.3725 per share on the Company's common stock. This was an increase of $0.0150 per share, or 4.2 percent from the previous quarterly dividend of $0.3575 per share.

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

CONTRACTUAL OBLIGATIONS

The following table provides a summary of our future contractual obligations as of December 31, 2017 (dollars in millions):

	2018	2019	2020	2021	2022	Thereafter
Avista Utilities:						
Long-term debt maturities	$ 273	$ 90	$ 52	$ —	$ 250	$ 964
Long-term debt to affiliated trusts	—	—	—	—	—	52
Interest payments on long-term debt [(1)]	74	66	62	60	50	880
Short-term borrowings	105	—	—	—	—	—
Energy purchase contracts [(2)]	267	247	210	181	179	1,243
Operating lease obligations [(3)]	1	—	—	—	—	2
Other obligations [(4)]	32	35	34	29	34	194
Information technology contracts [(5)]	1	1	1	—	—	—
Pension plan funding [(6)]	22	22	22	22	22	—
Unsettled interest rate swap derivatives [(7)]	61	(1)	(1)	7	—	—
AEL&P total contractual obligations [(8)]	15	15	15	16	16	283
Other businesses (consolidated)						
total contractual obligations [(9)]	8	22	4	1	—	4
Total contractual obligations	$ 859	$ 497	$ 399	$ 316	$ 551	$ 3,622

(1) Represents our estimate of interest payments on long-term debt, which is calculated based on the assumption that all debt is outstanding until maturity. Interest on variable rate debt is calculated using the rate in effect at December 31, 2017.

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

(3) Includes the interest component of the lease obligation.

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

(5) Includes information service contracts which are recorded to other operating expenses in the Consolidated Statements of Income.

(6) Represents our estimated cash contributions to pension plans and other postretirement benefit plans through 2022. We cannot reasonably estimate pension plan contributions beyond 2022 at this time and have excluded them from the table above.

(7) Represents the net mark-to-market fair value of outstanding unsettled interest rate swap derivatives as of December 31, 2017. Negative values in the table above represent contractual amounts that are owed to Avista Corp. by the counterparties. The values in the table above will change each period depending on fluctuations in market interest rates and could become either assets or liabilities. Also, the amounts in the table above are not reflective of cash collateral of $35.0 million and letters of credit of $5.0 million that are already posted with counterparties against the outstanding interest rate swap derivatives.

(8) Primarily relates to long-term debt and capital lease maturities and the related interest. AEL&P contractual commitments also include contractually required capital project funding and operating and maintenance costs associated with the Snettisham hydroelectric project. These costs are generally recovered through base retail rates.

(9) Primarily relates to operating lease commitments, venture fund commitments, and a commitment to fund a limited liability company in exchange for equity ownership, made by a subsidiary of Avista Capital. Also, there is a long-term debt maturity and the related interest associated with AERC.

The above contractual obligations do not include income tax payments. Also, asset retirement obligations are not included above and payments associated with these have historically been less than $1 million per year. There are approximately $17.5 million remaining asset retirement obligations as of December 31, 2017.

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

COMPETITION

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

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

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

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

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

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

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

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

Participants in the wholesale energy markets include:

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

ECONOMIC CONDITIONS AND UTILITY LOAD GROWTH

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

Avista Utilities

We track multiple economic indicators affecting the three largest metropolitan statistical areas in our Avista Utilities service area: Spokane, Washington, Coeur d'Alene, Idaho, and Medford, Oregon. The key indicators are employment change and unemployment rates. On an annual basis, 2017 showed positive job growth and lower unemployment rates in all three metropolitan areas. However, the unemployment rates in Spokane and Medford are still slightly above the national average. Key leading indicators such as initial unemployment claims and residential building permits, signal continued growth over the next 12 months. Therefore, in 2018, we expect economic growth in our service area to be slightly stronger than the U.S. as a whole.

Nonfarm employment (seasonally adjusted) in our eastern Washington, northern Idaho, and southwestern Oregon metropolitan service areas exhibited moderate growth between 2016 and 2017. In Spokane, Washington employment growth was 2.1 percent with gains in all major sectors except financial services. Employment increased by 1.7 percent in Coeur d'Alene, Idaho, reflecting gains in all major sectors except trade, transportation, and utilities; information; leisure and hospitality; and other services. In Medford, Oregon, employment growth was 2.3 percent, with gains in all major sectors except mining and logging; other services; and government. U.S. nonfarm sector jobs grew by 1.5 percent over the same period.

Seasonally adjusted average unemployment rates went down in 2017 from the year earlier in Spokane, Coeur d'Alene, and Medford. In Spokane the average rate was 6.6 percent in 2016 and declined to 5.5 percent in 2017; in Coeur d'Alene the average rate went from 4.8 percent to 3.9 percent; and in Medford the average rate declined from 5.8 percent to 4.6 percent. The U.S. rate declined from 4.9 percent to 4.3 percent over the same period.

Alaska Electric Light and Power Company

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

The Quarterly Census of Employment and Wages for Juneau shows employment declined 1.8 percent between the first half of 2016 and second half of 2017. The employment decline was centered in government; construction; trade, transportation, and utilities; financial activities; and professional and business services; leisure and hospitality; and education and health services. Government (including active duty military personnel) accounts for approximately 37 percent of total employment. Between 2016 and 2017, the non-seasonally adjusted unemployment rate increased from 4.4 percent to 4.6 percent.

Forecasted Customer and Load Growth

Based on our forecast for 2018 through 2021 for Avista Utilities' service area, we expect annual electric customer growth to average 1.1 percent, within a forecast range of 0.7 percent to 1.5 percent. We expect annual natural gas customer growth to average 1.5 percent, within a forecast range of 1 percent to 2 percent. We anticipate retail electric load growth to average 0.5 percent, within a forecast range of 0.2 percent and 0.8 percent. We expect natural gas load growth to average 1.3 percent, within a forecast range of 0.8 percent and 1.8 percent. The forecast ranges reflect (1) the inherent uncertainty associated with the economic assumptions on which forecasts are based and (2) the historic variability of natural gas customer and load growth.

In AEL&P's service area, we expect residential customer growth near 0 percent (no residential customer growth) for 2018 through 2021. We also expect no significant growth in commercial and government customers over the same period. We anticipate average annual total load growth will be in a narrow range around 0.3 percent, with residential load growth averaging 0.6 percent, commercial growth near 0 percent (no load growth); and government growth near 0 percent.

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

- assumptions relating to weather and economic and competitive conditions,
- internal analysis of company-specific data, such as energy consumption patterns,
- internal business plans,
- an assumption that we will incur no material loss of retail customers due to self-generation or retail wheeling, and
- an assumption that demand for electricity and natural gas as a fuel for mobility will for now be immaterial.

Changes in actual experience can vary significantly from our projections.

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

ENVIRONMENTAL ISSUES AND CONTINGENCIES

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

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

Environmental laws and regulations may:

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

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

Clean Air Act (CAA)

The CAA creates a number of requirements for our thermal generating plants. The Colstrip Generating Station, Kettle Falls Generating Station and Rathdrum Combustion Turbine all require CAA Title V operating permits. The Boulder Park Generating Station, Northeast Combustion Turbine and a number of other operations require minor source permits or simple source registration permits. We have secured these permits and operate to meet their requirements. These requirements can change over time as the CAA or applicable implementing regulations are amended and new permits are issued. We actively monitor legislative, regulatory and other program developments of the CAA that may impact our facilities.

Hazardous Air Pollutants (HAPs)

The EPA regulates hazardous air pollutants from a published list of industrial sources referred to as "source categories" which must meet control technology requirements if they emit one or more of the pollutants in significant quantities. In 2012, the EPA finalized the Mercury Air Toxic Standards (MATS) for the coal and oil-fired source category. 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 continue to review stack testing data and expect that no additional emission control systems will be needed for Units 3 & 4 MATS compliance.

Regional Haze Program

The EPA set a national goal of eliminating man-made visibility degradation in Class I areas by the year 2064. States are expected to take actions to make "reasonable progress" through 10-year plans. In the case where a State opts out of implementing the Regional Haze program, the EPA may act directly. In September 2012, the EPA finalized the Regional Haze federal implementation plan (FIP) for Montana; however, in May 2015, the Ninth circuit remanded the FIP back to the EPA. Colstrip Units 3 & 4 are not currently affected in the FIP, but are being evaluated in the 5-year Reasonable Progress Report submitted by the Montana Department of Environmental Quality (MDEQ) in August 2017. We do not anticipate any material impacts on Units 3 & 4 as a result of this report.

Coal Ash Management/Disposal

In 2015, the EPA issued a final rule regarding coal combustion residuals (CCRs), also termed coal combustion byproducts or coal ash. Colstrip, of which we are a 15 percent owner of Units 3 & 4, produces this byproduct. The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste. We, in conjunction with the other owners, developed a multi-year compliance plan to strategically address the new CCR requirements and existing state obligations while maintaining operational stability. Based on available information from the Colstrip operator, we review and update our asset retirement obligation (ARO) periodically. See "Note 9 of the Notes to Consolidated Financial Statements" for additional information regarding AROs.

In addition to an increase to our ARO, it is expected that there will be significant compliance costs at Colstrip in the future, both operating and capital costs, due to a series of incremental infrastructure improvements which are separate from the ARO. We cannot reasonably estimate the future compliance costs; however, we will update our ARO and compliance cost estimates as data becomes available.

The actual asset retirement costs and future compliance costs related to the CCR rule requirements may vary substantially from the estimates used to record the ARO due to uncertainty about the compliance strategies that will be used and the nature of available data used to estimate costs, such as the quantity of coal ash present at certain sites and the volume of fill that will be needed to cap and cover certain impoundments. We will coordinate with the plant operators and continue to gather additional data in future periods to make decisions about compliance strategies and the timing of closure activities. As additional information becomes available, we will update the ARO and future nonretirement compliance costs for these changes in estimates, which could be material. We expect to seek recovery of increased costs related to complying with the CCR rule through customer rates.

Climate Change

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

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

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

Climate Change—Federal Regulatory Actions

The EPA released the final rules for the Clean Power Plan (Final CPP) and the Carbon Pollution Standards (Final CPS) in August 2015. The Final CPP and the Final CPS are both intended to reduce the carbon dioxide (CO_2) emissions from certain coal-fired and natural gas electric generating units (EGUs). These rules were published in the Federal Register in October 2015 and were immediately challenged via lawsuits by other parties.

The Final CPP was promulgated pursuant to Section 111(d) of the CAA and applies to CO_2 emissions from existing EGUs. The Final CPP is intended to reduce national CO_2 emissions by approximately 32 percent below 2005 levels by 2030. The Final CPS rule was issued pursuant to Section 111(b) of the CAA and applies to the emissions of new, modified and reconstructed EGUs. The two rules are the first rules ever adopted by the U.S. federal government to comprehensively control and reduce CO_2 emissions from the power sector. The EPA also issued a proposed Federal Implementation Plan (Proposed FIP) for the Final CPP. The Final FIP that the EPA adopts could be imposed on states by the EPA, should a state decide not to develop its own plan.

The Final CPP establishes individual state emission reduction goals based upon the assumed potential for (1) heat rate improvements at coal-fired units, (2) increased utilization of natural gas-fired combined cycle plants, and (3) increased utilization of low or zero carbon emitting generation resources. As expressed in the final rule, states had until September 2016 to submit state compliance plans, with a potential for two-year extensions. A stay granted by the U.S. Supreme Court, and described below, pushed this date out pending the results of the case. Avista Corp. owns two EGUs that are subject to the Final CPP: its portion (15 percent of Units 3 & 4) of Colstrip in Montana and Coyote Springs 2 in Oregon. States may adopt rate-based or mass-based plans, and may choose to focus compliance on specific EGUs or adopt broader measures to reduce carbon emissions from this sector. The states in which Avista Utilities generates or delivers electricity, Washington, Idaho, Montana and Oregon, are at differing stages of evaluating options for developing state plans, which will define compliance approaches and obligations. Alaska was exempted in the Final CPP. The EPA may consider rulemaking in the future for Alaska and Hawaii, both states which lack regional grid connections.

In a separate but related rulemaking, the EPA finalized CO_2 new source performance standards (NSPS) for new, modified and reconstructed fossil fuel-fired EGUs under the CAA section 111(b). These EGUs fall into the same two categories of sources regulated by the Final CPP: steam generating units (also known as "utility boilers and IGCC units"), which primarily burn coal, and stationary combustion turbines, which primarily burn natural gas.

Greenhouse gas (GHG) emission standards could result in significant compliance costs. Such standards could also preclude us from developing, operating or contracting with certain types of generating plants. Additionally, the Climate Action Plan requirements related to preparing the U.S. for the impacts of climate change could affect us and others in the industry as transmission system modifications to improve resiliency may be needed in order to meet those requirements.

The promulgated and proposed GHG rulemakings mentioned above have been legally challenged in multiple venues. On February 9, 2016, the U.S. Supreme Court granted a request for stay, halting implementation of the Final CPP. On March 28, 2017, the Department of Justice filed a motion with the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) requesting that the Court hold the cases challenging the Final CPP in abeyance while the EPA reviews the final rules applicable to existing, as well as to new, modified, and reconstructed electric generating units pursuant to an Executive Order issued by President Trump. The Executive Order also instructed the EPA to review the Final CPP rule. On April 28, 2017 the D.C. Circuit issued orders to hold the litigation regarding the Clean Air Act §111(d) Clean Power Plan and the §111(b) New Source Performance Standards for power plants in abeyance for a period of 60 days with status reports due from the EPA every 30 days. On October 16, 2017, the EPA gave notice of proposed rule-making to repeal the Final CPP. On December 28, 2017, the EPA published an Advanced Notice of Proposed Rulemaking seeking comments on the potential for a Final CPP replacement rule. Comment periods on both notices remain open. Given these ongoing developments, we cannot fully predict the outcome or estimate the extent to which our facilities may be impacted by these regulations at this time. We intend to seek recovery of costs related to compliance with these requirements through the ratemaking process.

Climate Change—State Legislation and State Regulatory Activities

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

Washington and Oregon apply a GHG emissions performance standard (EPS) to electric generation facilities used to serve retail loads in their jurisdictions, whether the facilities are located within those respective states or elsewhere. The EPS prevents utilities from constructing or purchasing generation facilities, or entering into power purchase agreements of five years or longer duration to purchase energy produced by plants that, in any case, have emission levels higher than 1,100 pounds of GHG per MWh. The Washington State Department of Commerce initiated a process to adopt a lower emissions performance standard in 2012, and is in the process of updating the standard, which is currently set at 970 pounds of GHG per MWh. We are engaging in the next process to revise the EPS, which began in 2017 and should conclude in 2018. In addition, citizens, local governments and states, particularly in Oregon and Washington, actively bring forth climate-related proposals that could impact our business and operations. We monitor and engage such activities as appropriate, and intend to seek recovery of costs related to new requirements resulting from such activities through the ratemaking process.

Washington

Energy Independence Act (EIA)

The EIA in Washington requires electric utilities with over 25,000 customers to acquire qualified renewable energy resources and/or renewable energy credits equal to 15 percent of the utility's total retail load in Washington in 2020. I-937 also requires these utilities to meet biennial energy conservation targets beginning in 2012. The renewable energy standard increased from three percent in 2012 to nine percent in 2016 and will increase to 15 percent in 2020. Failure to comply with renewable energy and efficiency standards could result in penalties of $50 per MWh or greater assessed against a utility for each MWh it is deficient in meeting a standard. We have met, and will continue to meet, the requirements of the EIA through a variety of renewable energy generating means, including, but not limited to, some combination of hydro upgrades, wind, biomass and renewable energy credits. In 2012, the EIA was amended in such a way that our Kettle Falls GS and certain other biomass energy facilities, which commenced operation before March 31, 1999, are considered resources that may be used to meet the renewable energy standards.

Clean Air Rule

In September 2016, the Washington State Department of Ecology (Ecology) adopted the Clean Air Rule (CAR) to cap and reduce GHG emissions across the State of Washington in pursuit of the State's GHG goals, which were enacted in 2008 by the Washington State Legislature. The CAR applies to sources of annual GHG 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 that would be regulated under the CAR. Parties covered by the regulation must reduce emissions by 1.7 percent annually until 2035. Compliance can be demonstrated by achieving emission reductions and/or surrendering Emission Reduction Units (ERU), which are generated by parties that achieve reductions greater than required by the rule. ERUs can also take the form of renewable energy credits from renewable resources located in Washington, carbon emission offsets, and allowances acquired from an organized cap and trade market, such as that operating in California. In addition to the CAR's applicability to our burning of fuel as an electric utility, the CAR applies to us as a natural gas distribution company, for the emissions associated with the use of the natural gas we provide our customers who are not already covered under the regulation.

In September 2016, Avista Corp., Cascade Natural Gas Corp., NW Natural and Puget Sound Energy (PSE) (collectively, Petitioners) jointly filed an action in the U.S. District Court for the Eastern District of Washington challenging Ecology's promulgated CAR. The four companies also filed litigation in Thurston County Superior Court.

The case in the U.S. District Court has been tolled while the state court case proceeds. On December 15, 2017, the Thurston County Superior Court issued a ruling invalidating the CAR. Motions are pending in front of the Court and it is unknown if the Court's ruling will be appealed. We cannot fully predict the outcome of these matters at this time, but plan to seek recovery of costs related to compliance with surviving requirements through the ratemaking process.

Colstrip 3 & 4 Considerations

In February 2014, the WUTC issued a letter finding that PSE's 2013 Electric IRP meets the requirements of the Revised Code of Washington and the Washington Administrative Code. The letter does not constitute approval of any aspect of the plan. In its letter, however, the WUTC expressed concern regarding the continued operation of the Colstrip plant as a resource to serve retail customers. Although the WUTC recognized that the results of the analyses presented by PSE "differed significantly between [Colstrip] Units 1 & 2 and Units 3 & 4," the WUTC did not limit its concerns solely to Colstrip Units 1 & 2. The WUTC recommended that PSE "consult with WUTC staff to consider a Colstrip Proceeding to determine the prudency of new investment in Colstrip before it is made or, alternatively, a closure or partial-closure plan." As part of the Sierra Club litigation that was settled in 2016, Units 1 & 2 are scheduled to close by July 2022. In 2017, the WUTC issued an Order in PSE's general rate case accelerating PSE's depreciation of Units 3 & 4 to 2027 from 2044 and 2045, respectively, directing PSE to contribute $10 million from a combination of sources to a community transition fund to mitigate social and economic impacts from the closure of Colstrip, and encouraging PSE to engage stakeholders in a dialogue about utilizing surplus capacity on the Colstrip transmission system. As a 15 percent owner of Colstrip Units 3 & 4, we cannot estimate the effect of such proceeding, should it occur, on the future ownership, operation and operating costs of our share of Colstrip Units 3 & 4. Our remaining investment in Colstrip Units 3 & 4 as of December 31, 2017 was $124.4 million.

In Oregon, legislation was enacted in 2016 which requires Portland General Electric and PacifiCorp to remove coal-fired generation from their Oregon 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.

Threatened and Endangered Species and Wildlife

A number of species of fish in the Northwest are listed as threatened or endangered under the Federal Endangered Species Act (ESA). Efforts to protect these and other species have not significantly impacted generation levels at our hydroelectric facilities, nor operations of our thermal plants or electrical distribution and transmission system. We are implementing fish protection measures at our hydroelectric project on the Clark Fork River under a 45-year FERC operating license for Cabinet Gorge and Noxon Rapids (issued March 2001) that incorporates a comprehensive settlement agreement. The restoration of native salmonid fish, including bull trout, is a key part of the agreement. The result is a collaborative native salmonid restoration program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana on the lower Clark Fork River, consistent with requirements of the FERC license. The U.S. Fish & Wildlife Service issued an updated Critical Habitat Designation for bull trout in 2010 that includes the lower Clark Fork River, as well as portions of the Coeur d'Alene basin within our Spokane River Project area, and issued a final Bull Trout Recovery Plan under the ESA. Issues related to these activities are expected to be resolved through the ongoing collaborative effort of our Clark Fork and Spokane River FERC licenses. See "Fish Passage at Cabinet Gorge and Noxon Rapids" in "Note 19 of the Notes to Consolidated Financial Statements" for further information.

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

We are also aware of other threatened and endangered species and issues related to them that could be impacted by our operations and we make every effort to comply with all laws and regulations relating to these threatened and endangered species. We expect costs associated with these compliance efforts to be recovered through the ratemaking process.

Other

For other environmental issues and other contingencies see "Note 19 of the Notes to Consolidated Financial Statements."

ENTERPRISE RISK MANAGEMENT

The material risks to our businesses are discussed in "Item 1A. Risk Factors," "Forward-Looking Statements," as well as "Environmental Issues and Contingencies." The following discussion focuses on our mitigation processes and procedures to address these risks.

We consider the management of these risks an integral part of managing our core businesses and a key element of our approach to corporate governance.

Risk management includes identifying and measuring various forms of risk that may affect the Company. We have an enterprise risk management process for managing risks throughout our organization. Our Board of Directors and its Committees take an active role in the oversight of risk affecting the Company. Our risk management department facilitates the collection of risk information across the Company, providing senior management with a consolidated view of the Company's major risks and risk mitigation measures. Each area identifies risks and implements the related mitigation measures. The enterprise risk process supports management in identifying, assessing, quantifying, managing and mitigating the risks. Despite all risk mitigation measures, however, risks are not eliminated.

Our primary identified categories of risk exposure are:

- Financial
- Utility regulatory
- Energy commodity
- Operational
- Compliance
- Technology
- Strategic
- External Mandates

FINANCIAL RISK

Financial risk is any risk that could have a direct material impact on the financial performance or financial viability of the Company. Broadly, financial risks involve variation of earnings and liquidity. Underlying risks include, but are not limited to, those described in "Item 1A. Risk Factors."

We mitigate financial risk in a variety of ways including through oversight from the Finance Committee of our Board of Directors and from senior management. Our Regulatory department is also critical in risk mitigation as they have regular communications with state commission regulators and staff and they monitor and develop rate strategies for the Company. Rate strategies, such as decoupling, help mitigate the impacts of revenue fluctuations due to weather, conservation or the economy. We also have a Treasury department that monitors our daily cash position and future cash flow needs, as well as monitoring market conditions to determine the appropriate course of action for capital financing and/or hedging strategies.

Weather Risk

To partially mitigate the risk of financial underperformance due to weather-related factors, we developed decoupling rate mechanisms that were approved by the Washington, Idaho and Oregon commissions. Decoupling mechanisms are designed to break the link between a utility's revenues and consumers' energy usage and instead provide revenue based on the number of customers, thus mitigating a large portion of the risk associated with lower customer loads. See "Regulatory Matters" for further discussion of our decoupling mechanisms.

Access to Capital Markets

Our capital requirements rely to a significant degree on regular access to capital markets. We actively engage with rating agencies, banks, investors and state public utility commissions to understand and address the factors that support access to capital markets on reasonable terms. We manage our capital structure to maintain a financial risk profile that we believe these parties will deem prudent. We forecast cash requirements to determine liquidity needs, including sources and variability of cash flows that may arise from our spending plans or from external forces, such as changes in energy prices or interest rates. Our financial and operating forecasts consider various metrics that affect credit ratings. Our regulatory strategies include working with state public utility commissions and filing for rate changes as appropriate to meet financial performance expectations.

Interest Rate Risk

Uncertainty about future interest rates causes risk related to a portion of our existing debt, our future borrowing requirements, and our pension and other postretirement benefit obligations. We manage debt interest rate exposure by limiting our variable rate debt to a percentage of total capitalization of the Company. We hedge a portion of our interest rate risk on forecasted debt issuances with financial derivative instruments, which may include interest rate swaps and U.S. Treasury lock agreements. The Finance Committee of our Board of Directors periodically reviews and discusses interest rate risk management processes and the steps management has undertaken to control interest rate risk. Our RMC also reviews our interest rate risk management plan. Additionally, interest rate risk is managed by monitoring market conditions when timing the issuance of long-term debt and optional debt redemptions and establishing fixed rate long-term debt with varying maturities.

Our interest rate swap derivatives are considered economic hedges against the future forecasted interest rate payments of our long-term debt. Interest rates on our long-term debt are generally set based on underlying U.S. Treasury rates plus credit spreads, which are based on our credit ratings and prevailing market prices for debt. The interest rate swap derivatives hedge against changes in the U.S. Treasury rates but do not hedge the credit spread.

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

See "Regulatory Matters—Washington General Rate Cases" for a discussion of the recommendation by the WUTC Staff to deny the recovery of costs incurred in the settlement of certain interest rate swaps and the financial impact of such a denial. Depending on the outcome of this proceeding, we could determine to not manage interest rate risk through swap transactions in the future.

The following table summarizes our interest rate swap derivatives outstanding as of December 31, 2017 and December 31, 2016 (dollars in thousands):

	December 31, 2017	December 31, 2016
Number of agreements	29	33
Notional amount	$ 450,000	$ 500,000
Mandatory cash settlement dates	2018 to 2022	2017 to 2022
Short-term derivative assets [1]	$ 2,327	$ 3,393
Long-term derivative assets [1]	2,576	5,357
Short-term derivative liability [1] [2]	(34,447)	(6,025)
Long-term derivative liability [1] [2]	(1,522)	(28,705)

(1) There are offsetting regulatory assets and liabilities for these items on the Consolidated Balance Sheets in accordance with regulatory accounting practices.

(2) The balance as of December 31, 2017 and December 31, 2016 reflects the offsetting of $35.0 million and $34.9 million, respectively, of cash collateral against the net derivative positions where a legal right of offset exists.

We estimate that a 10-basis-point increase in forward LIBOR interest rates as of December 31, 2017 would decrease the interest rate swap derivative net liability by $9.7 million, while a 10-basis-point decrease would increase the interest rate swap derivative net liability by $10.0 million.

We estimated that a 10-basis-point increase in forward LIBOR interest rates as of December 31, 2016 would have decreased the interest rate swap derivative net liability by $10.4 million, while a 10-basis-point decrease would increase the interest rate swap derivative net liability by $10.7 million.

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

The following table shows our long-term debt (including current portion) and related weighted-average interest rates, by expected maturity dates as of December 31, 2017 (dollars in thousands):

	2018	2019	2020	2021	2022	Thereafter	Total	Fair Value
Fixed rate long-term debt [1]	$ 272,500	$ 105,000	$ 52,000	$ —	$ 250,000	$ 1,038,500	$ 1,718,000	$ 1,878,381
Weighted-average interest rate	6.07%	5.22%	3.89%	—	5.13%	4.77%	5.03%	
Variable rate long-term debt to affiliated trusts	—	—	—	—	—	$ 51,547	$ 51,547	$ 41,882
Weighted-average interest rate	—	—	—	—	—	2.36%	2.36%	

(1) These balances include the fixed rate long-term debt of Avista Corp., AEL&P and AERC.

Our pension plan is exposed to interest rate risk because the value of pension obligations and other postretirement obligations vary directly with changes in the discount rates, which are derived from end-of-year market interest rates. In addition, the value of pension investments and potential income on pension investments is partially affected by interest rates because a portion of pension investments are in fixed income securities. The Finance Committee of the Board of Directors approves investment policies, objectives and strategies that seek an appropriate return for the pension plan and it reviews and approves changes to the investment and funding policies. We manage interest rate risk associated with our pension and other postretirement benefit plans by investing a targeted amount of pension plan assets in fixed income investments that have maturities with similar profiles to future projected benefit obligations. See "Note 10 of the Notes to Consolidated Financial Statements" for further discussion of our investment policy associated with the pension assets.

Credit Risk

Counterparty Non-Performance Risk

Counterparty non-performance risk relates to potential losses that we would incur as a result of non-performance of contractual obligations by counterparties to deliver energy or make financial settlements.

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

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

We seek to mitigate credit risk by:

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

The extent of transactions conducted through exchanges has increased, as many market participants have shown a preference toward exchange trading and have reduced bilateral transactions. We actively monitor the collateral required by such exchanges to effectively manage our capital requirements.

Counterparties' credit exposure to us is dynamic in normal markets and may change significantly in more volatile markets. The amount of potential default risk to us from each counterparty depends on the extent of forward contracts, unsettled transactions, interest rates and market prices. There is a risk that we do not obtain sufficient additional collateral from counterparties that are unable or unwilling to provide it.

Credit Risk Liquidity Considerations

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

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

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

As of December 31, 2017, we had cash deposited as collateral of $39.5 million and letters of credit of $23.0 million outstanding related to our energy derivative contracts. Price movements and/or a downgrade in our credit ratings could impact further the amount of collateral required. See "Credit Ratings" for further information. For example, in addition to limiting our ability to conduct transactions, if our credit ratings were lowered to below "investment grade" based on our positions outstanding at December 31, 2017, we would potentially be required to post additional collateral of up to $2.6 million. This amount is different from the amount disclosed in "Note 6 of the Notes to Consolidated Financial Statements" because, while this analysis includes contracts that are not considered derivatives in addition to the contracts considered in Note 6, this analysis also takes into account contractual threshold limits that are not considered in Note 6. Without contractual threshold limits, we would potentially be required to post additional collateral of $4.6 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 December 31, 2017, we had interest rate swap agreements outstanding with a notional amount totaling $450.0 million and we had deposited cash in the amount of $35.0 million and letters of credit of $5.0 million as collateral for these interest rate swap derivatives. If our credit ratings were lowered to below "investment grade" based on our interest rate swap derivatives outstanding at December 31, 2017, we would have to post $18.8 million of additional collateral.

Foreign Currency Risk

A significant portion of our utility natural gas supply (including fuel for electric generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of our short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices. The short-term natural gas transactions are typically settled within sixty days with U.S. dollars. We economically hedge a portion of the foreign currency risk by purchasing Canadian currency exchange contracts when such commodity transactions are initiated. This risk has not had a material effect on our financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations are included with natural gas supply costs for ratemaking.

Further information for derivatives and fair values is disclosed at "Note 6 of the Notes to Consolidated Financial Statements" and "Note 16 of the Notes to Consolidated Financial Statements."

UTILITY REGULATORY RISK

Because we are primarily a regulated utility, we face the risk that regulators may not grant rates that provide timely or sufficient recovery of our costs or allow a reasonable rate of return for our shareholders. This includes costs associated with our investment in rate base, as well as commodity costs and other operating and financing expenses.

We mitigate regulatory risk through oversight from our Board of Directors and from senior management. We have a separate regulatory group which communicates with commission regulators and staff regarding the Company's business plans and concerns. The regulatory group also considers the regulator's priorities and rate policies and makes recommendations to senior management on regulatory strategy for the Company. See "Regulatory Matters" for further discussion of regulatory matters affecting our Company.

ENERGY COMMODITY RISK

Energy commodity risks are associated with fulfilling our obligation to serve customers, managing variability of energy facilities, rights and obligations and fulfilling the terms of our energy commodity agreements with counterparties. These risks include, among other things, those described in "Item 1A. Risk Factors."

We mitigate energy commodity risk primarily through our energy resources risk policy, which includes oversight from the RMC and oversight from the Audit Committee and the Environmental, Technology and Operations Committee of our Board of Directors. In conjunction with the oversight committees, our management team develops hedging strategies, detailed resource procurement plans, resource optimization strategies and long-term integrated resource planning to mitigate some of the risk associated with energy commodities. The various plans and strategies are monitored daily and developed with quantitative methods.

Our energy resources risk policy includes our wholesale energy markets credit policy and control procedures to manage energy commodity price and credit risks. Nonetheless, adverse changes in commodity prices, generating capacity, customer loads, regulation and other factors may result in losses of earnings, cash flows and/or fair values.

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

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

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

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2017 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]
2018	$ (8,267)	$ (501)	$ 1,022	$ (36,834)	$ 35	$ 4,100	$ (374)	$ 15,829
2019	(4,950)	(1,159)	(570)	(17,814)	(13)	4,621	(932)	6,395
2020	—	—	(766)	(1,882)	—	(194)	(1,050)	—
2021	—	—	—	—	—	—	(655)	—
2022	—	—	—	—	—	—	—	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2016 that were 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]
2017	$ (4,274)	$ 1,939	$ 97	$ (4,005)	$ (225)	$ 576	$ (2,036)	$ (3,440)
2018	(5,598)	—	—	(2,170)	(33)	854	(910)	709
2019	(3,123)	—	(235)	(3,732)	(40)	975	(927)	103
2020	—	—	(266)	(370)	—	—	(1,288)	—
2021	—	—	—	—	—	—	(869)	—
Thereafter	—	—	—	—	—	—	—	—

(1) Physical transactions represent commodity transactions where 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, swap derivatives, options, or forward contracts.

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

See "Item 1. Business—Electric Operations," "Item 1. Business—Natural Gas Operations," and "Item 1A. Risk Factors" for additional discussion of the risks associated with Energy Commodities.

OPERATIONAL RISK

Operational risk involves potential disruption, losses, or excess costs arising from external events or inadequate or failed internal processes, people and systems. Our operations are subject to operational and event risks that include, but are not limited to, those described in "Item 1A. Risk Factors."

To manage operational and event risks, we maintain emergency operating plans, business continuity and disaster recovery plans, maintain insurance coverage against some, but not all, potential losses and seek to negotiate indemnification arrangements with contractors for certain event risks. In addition, we design and follow detailed vegetation management and asset management inspection plans, which help mitigate wildfire and storm event risks, as well as identify utility assets which may be failing and in need of repair or replacement. We also have an Emergency Operating Center, which is a team of employees that plan for and train to deal with potential emergencies or unplanned outages at our facilities, resulting from natural disasters or other events. To prevent unauthorized access to our facilities, we have both physical and cyber security in place.

To address the risk related to fuel cost, availability and delivery restraints, we have an energy resources risk policy, which includes our wholesale energy markets credit policy and control procedures to manage energy commodity price and credit risks. Development of the energy resources risk policy includes planning for sufficient capacity to meet our customer and wholesale energy delivery obligations. See further discussion of the energy resources risk policy above.

Oversight of the operational risk management process is performed by the Environmental, Technology and Operations Committee of our Board of Directors and from senior management with input from each operating department.

COMPLIANCE RISK

Compliance risk is the potential consequences of legal or regulatory sanctions or penalties arising from the failure of the Company to comply with requirements of applicable laws, rules and regulations. We have extensive compliance obligations. Our primary compliance risks and obligations include, among others, those described in "Item 1A. Risk Factors."

We mitigate compliance risk through oversight from the Environmental, Technology and Operations Committee and the Audit Committee of our Board of Directors and from senior management, including our Chief Compliance Officer. We also have separate Regulatory and Environmental Compliance departments that monitor legislation, regulatory orders and actions to determine the overall potential impact to our Company and develop strategies for complying with the various rules and regulations. We also engage outside attorneys and consultants, when necessary, to help ensure compliance with laws and regulations.

See "Item 1. Business, Regulatory Issues" through "Item 1. Business, Reliability Standards" and "Environmental Issues and Contingencies" for further discussion of compliance issues that impact our Company.

TECHNOLOGY RISK

Our primary technology risks are described in "Item 1A. Risk Factors."

We mitigate technology risk through trainings and exercises at all levels of the Company. The Environmental, Technology and Operations Committee of our Board of Directors along with senior management are regularly briefed on security policy, programs and incidents. Annual cyber and physical training and testing of employees are included in our enterprise security program. Our enterprise business continuity program facilitates business impact analysis of core functions for development of emergency operating plans, and coordinates annual testing and training exercises.

Technology governance is led by senior management, which includes new technology strategy, risk planning and major project planning and approval. The technology project management office and enterprise capital planning group provide project cost, timeline and schedule oversight. In addition, there are independent third-party audits of our critical infrastructure security program and our business risk security controls.

We have a Technology department dedicated to securing, maintaining, evaluating and developing our information technology systems. There are regular training sessions for the technology and security team. This group also evaluates the Company's technology for obsolescence and makes recommendations for upgrading or replacing systems as necessary. Additionally, this group monitors for intrusion and security events that may include a data breach or attack on our operations.

STRATEGIC RISK

Strategic risk relates to the potential impacts resulting from incorrect assumptions about external and internal factors, inappropriate business plans, ineffective business strategy execution, or the failure to respond in a timely manner to changes in the regulatory, macroeconomic or competitive environments. Our primary strategic risks include, among others, those described in "Item 1A. Risk Factors."

We mitigate strategic risk through detailed oversight from the Board of Directors and from senior management. We also have a Chief Strategy Officer that leads strategic initiatives, to search for and evaluate opportunities for the Company and makes recommendations to senior management. We not only focus on whether opportunities are financially viable, but also consider whether these opportunities fall within our core policies and our core business strategies. We mitigate our reputational risk primarily through a focus on adherence to our core policies, including our Code of Conduct, maintaining an appropriate Company culture and tone at the top, and through communication and engagement of our external stakeholders.

EXTERNAL MANDATES RISK

External mandate risk involves forces outside the Company, which may include significant changes in customer expectations, disruptive technologies that result in obsolescence of our business model and government action that could impact the Company. See "Environmental Issues and Contingencies" and "Forward-Looking Statements" for a discussion of or reference to our external mandates risks.

We mitigate external mandate risk through detailed oversight from the Environmental, Technology and Operations Committee of our Board of Directors and from senior management. We have a Climate Council which meets internally to assess the potential impacts of climate policy to our business and to identify strategies to plan for change. We also have employees dedicated to actively engage and monitor federal, state and local government positions and legislative actions that may affect us or our customers.

To prevent the threat of municipalization, we work to build strong relationships with the communities we serve through, among other things:

- communication and involvement with local business leaders and community organizations,
- providing customers with a multitude of limited income initiatives, including energy fairs, senior outreach and low income workshops, mobile outreach strategy and a Low Income Rate Assistance Plan,
- tailoring our internal company initiatives to focus on choices for our customers, to increase their overall satisfaction with the Company, and
- engaging in the legislative process in a manner that fosters the interests of our customers and the communities we serve.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The information required by this item is set forth in the Enterprise Risk Management section of "Item 7. Management's Discussion and Analysis" and is incorporated herein by reference.

Item 8. Financial Statements and Supplementary Data

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of
Avista Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 20, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 20, 2018

We have served as the Company's auditor since 1933.

CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Years Ended December 31,

Dollars in thousands, except per share amounts

	2017	2016	2015
Operating Revenues:			
Utility revenues	$ 1,423,386	$ 1,418,914	$ 1,456,091
Non-utility revenues	22,543	23,569	28,685
Total operating revenues	1,445,929	1,442,483	1,484,776
Operating Expenses:			
Utility operating expenses:			
Resource costs	524,566	551,366	656,964
Other operating expenses	317,813	315,795	303,221
Acquisition costs	14,618	—	—
Depreciation and amortization	171,281	160,514	143,499
Taxes other than income taxes	106,752	98,735	97,657
Non-utility operating expenses:			
Other operating expenses	25,650	25,501	29,526
Depreciation and amortization	740	769	695
Total operating expenses	1,161,420	1,152,680	1,231,562
Income from operations	284,509	289,803	253,214
Interest expense	95,361	86,496	79,968
Interest expense to affiliated trusts	831	634	473
Capitalized interest	(3,310)	(2,651)	(3,546)
Other income—net	(7,063)	(10,078)	(9,300)
Income from continuing operations before income taxes	198,690	215,402	185,619
Income tax expense	82,758	78,086	67,449
Net income from continuing operations	115,932	137,316	118,170
Net income from discontinued operations (Note 5)	—	—	5,147
Net income	115,932	137,316	123,317
Net income attributable to noncontrolling interests	(16)	(88)	(90)
Net income attributable to Avista Corp. shareholders	$ 115,916	$ 137,228	$ 123,227
Amounts attributable to Avista Corp. shareholders:			
Net income from continuing operations	$ 115,916	$ 137,228	$ 118,080
Net income from discontinued operations	—	—	5,147
Net income attributable to Avista Corp. shareholders	$ 115,916	$ 137,228	$ 123,227
Weighted-average common shares outstanding (thousands)—basic	64,496	63,508	62,301
Weighted-average common shares outstanding (thousands)—diluted	64,806	63,920	62,708
Earnings per common share attributable to Avista Corp. shareholders—basic:			
Earnings per common share from continuing operations	$ 1.80	$ 2.16	$ 1.90
Earnings per common share from discontinued operations	—	—	0.08
Total earnings per common share attributable to Avista Corp. shareholders—basic	$ 1.80	$ 2.16	$ 1.98
Earnings per common share attributable to Avista Corp. shareholders—diluted:			
Earnings per common share from continuing operations	$ 1.79	$ 2.15	$ 1.89
Earnings per common share from discontinued operations	—	—	0.08
Total earnings per common share attributable to Avista Corp. shareholders—diluted	$ 1.79	$ 2.15	$ 1.97
Dividends declared per common share	$ 1.43	$ 1.37	$ 1.32

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

For the Years Ended December 31,

Dollars in thousands

	2017	2016	2015
Net income	$ 115,932	$ 137,316	$ 123,317
Other Comprehensive Income (Loss):			
Change in unfunded benefit obligation for pension and other postretirement benefit plans—net of taxes of $(281), $(495) and $667, respectively	(522)	(918)	1,238
Total other comprehensive income (loss)	(522)	(918)	1,238
Comprehensive income	115,410	136,398	124,555
Comprehensive income attributable to noncontrolling interests	(16)	(88)	(90)
Comprehensive income attributable to Avista Corporation shareholders	$ 115,394	$ 136,310	$ 124,465

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS

Avista Corporation
As of December 31,
Dollars in thousands

	2017	2016
Assets:		
Current Assets:		
Cash and cash equivalents	$ 16,172	$ 8,507
Accounts and notes receivable—less allowances of $5,132 and $5,026, respectively	185,664	180,265
Regulatory asset for energy commodity derivatives	24,991	11,365
Materials and supplies, fuel stock and stored natural gas	58,075	53,314
Income taxes receivable	314	48,265
Other current assets	52,318	49,625
Total current assets	337,534	351,341
Net Utility Property:		
Utility plant in service	5,853,308	5,506,499
Construction work in progress	157,839	150,474
Total	6,011,147	5,656,973
Less: Accumulated depreciation and amortization	1,612,337	1,509,473
Total net utility property	4,398,810	4,147,500
Other Non-current Assets:		
Investment in affiliated trusts	11,547	11,547
Goodwill	57,672	57,672
Other property and investments—net and other non-current assets	83,912	72,224
Total other non-current assets	153,131	141,443
Deferred Charges:		
Regulatory assets for deferred income tax	90,315	109,853
Regulatory assets for pensions and other postretirement benefits	209,115	240,114
Other regulatory assets	127,328	135,751
Regulatory asset for interest rate swaps	169,704	161,508
Non-current regulatory asset for energy commodity derivatives	18,967	16,919
Other deferred charges	9,828	5,326
Total deferred charges	625,257	669,471
Total assets	$ 5,514,732	$ 5,309,755

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS (CONTINUED)

Avista Corporation

As of December 31,

Dollars in thousands

	2017	2016
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 107,289	$ 115,545
Current portion of long-term debt and capital leases	277,438	3,287
Short-term borrowings	105,398	120,000
Current energy commodity derivative liabilities	8,848	7,035
Accrued interest	16,351	15,869
Accrued taxes other than income taxes	33,802	33,374
Deferred natural gas costs	37,474	30,820
Current portion of pensions and other postretirement benefits	11,544	10,994
Current unsettled interest rate swap derivative liabilities	34,447	6,025
Other current liabilities	64,911	64,579
Total current liabilities	697,502	407,528
Long-term debt and capital leases	1,491,799	1,678,717
Long-term debt to affiliated trusts	51,547	51,547
Regulatory liability for utility plant retirement costs	285,786	273,983
Pensions and other postretirement benefits	203,566	226,552
Deferred income taxes	466,630	840,928
Regulatory liability for excess deferred income taxes	442,319	—
Non-current interest rate swap derivative liabilities	1,522	28,705
Other non-current liabilities, regulatory liabilities and deferred credits	143,577	153,319
Total liabilities	3,784,248	3,661,279
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Equity:		
Avista Corporation Shareholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 65,494,333 and 64,187,934 shares issued and outstanding as of December 31, 2017 and December 31, 2016, respectively	1,133,448	1,075,281
Accumulated other comprehensive loss	(8,090)	(7,568)
Retained earnings	604,470	581,014
Total Avista Corporation shareholders' equity	1,729,828	1,648,727
Noncontrolling Interests	656	(251)
Total equity	1,730,484	1,648,476
Total liabilities and equity	$ 5,514,732	$ 5,309,755

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

	2017	2016	2015
Operating Activities:			
Net income	$ 115,932	$ 137,316	$ 123,317
Non-cash items included in net income:			
Depreciation and amortization	175,655	164,925	147,835
Provision for deferred income taxes	69,657	124,543	51,801
Power and natural gas cost amortizations (deferrals)—net	11,741	16,835	21,358
Amortization of debt expense	3,254	3,477	3,526
Amortization of investment in exchange power	2,450	2,450	2,450
Stock-based compensation expense	7,359	7,891	6,914
Equity-related AFUDC	(6,669)	(8,475)	(8,331)
Pension and other postretirement benefit expense	37,074	38,786	37,050
Amortization of Spokane Energy contract	—	14,694	13,508
Gain on sale of Ecova	—	—	(777)
Other regulatory assets and liabilities and deferred debits and credits	(9,144)	(26,245)	4,569
Change in decoupling regulatory deferral	24,179	(29,789)	(10,933)
Other	1,860	5,557	(517)
Contributions to defined benefit pension plan	(22,000)	(12,000)	(12,000)
Cash paid on settlement of interest rate swap derivatives	(11,302)	(53,966)	—
Cash received on settlement of interest rate swap derivatives	2,479	—	—
Changes in certain current assets and liabilities:			
Accounts and notes receivable	(9,270)	(17,170)	(10,538)
Materials and supplies, fuel stock and stored natural gas	(4,767)	834	12,208
Collateral posted for derivative instruments	(22,394)	10,712	(13,301)
Income taxes receivable	53,414	(33,923)	19,772
Other current assets	(2,106)	(3,907)	2,338
Accounts payable	(8,162)	5,176	(8,138)
Other current liabilities	1,058	10,546	(6,471)
Net cash provided by operating activities	410,298	358,267	375,640
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(412,339)	(406,644)	(393,425)
Issuance of notes receivable at subsidiaries	(3,700)	(10,094)	(2,307)
Repayments from notes receivable at subsidiaries	—	5,000	—
Equity and property investments made by subsidiaries	(13,680)	(13,097)	(1,944)
Distributions received from investments	1,915	—	—
Proceeds from sale of Ecova—net of cash sold	—	—	13,856
Other	(6,299)	(7,631)	(4,007)
Net cash used in investing activities	$ (434,103)	$ (432,466)	$ (387,827)

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (CONTINUED)

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

	2017	2016	2015
Financing Activities:			
Net increase (decrease) in short-term borrowings	$ (15,000)	$ 15,000	$ —
Proceeds from issuance of long-term debt	90,000	245,000	100,000
Redemption and maturity of long-term debt and capital leases	(3,287)	(163,167)	(2,905)
Maturity of nonrecourse long-term debt of Spokane Energy	—	—	(1,431)
Issuance of common stock—net of issuance costs	56,380	66,953	1,560
Repurchase of common stock	—	—	(2,920)
Cash dividends paid	(92,460)	(87,154)	(82,397)
Other	(4,163)	(4,410)	(11,379)
Net cash provided by financing activities	31,470	72,222	528
Net increase (decrease) in cash and cash equivalents	7,665	(1,977)	(11,659)
Cash and cash equivalents at beginning of year	8,507	10,484	22,143
Cash and cash equivalents at end of year	$ 16,172	$ 8,507	$ 10,484
Supplemental Cash Flow Information:			
Cash paid (received) during the year:			
Interest	$ 95,499	$ 86,319	$ 79,673
Income taxes paid	5,579	5,403	27,239
Income tax refunds	(47,086)	(18,861)	(37,200)
Non-cash financing and investing activities:			
Accounts payable for capital expenditures	31,157	30,252	35,248

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF EQUITY

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

	2017	2016	2015
Common Stock, Shares:			
Shares outstanding at beginning of year	64,187,934	62,312,651	62,243,374
Shares issued through equity compensation plans	214,925	203,727	125,620
Shares issued through Employee Investment Plan (401-K)	21,474	26,556	33,057
Shares issued through sales agency agreements	1,070,000	1,645,000	—
Shares repurchased	—	—	(89,400)
Shares outstanding at end of year	65,494,333	64,187,934	62,312,651
Common Stock, Amount:			
Balance at beginning of year	$ 1,075,281	$ 1,004,336	$ 999,960
Equity compensation expense	6,530	7,065	6,035
Issuance of common stock through equity compensation plans	720	624	462
Issuance of common stock through Employee Investment Plan (401-K)	939	1,061	1,099
Issuance of common stock through sales agency agreements—net of issuance costs	54,721	65,267	—
Payment of minimum tax withholdings for share-based payment awards	(3,552)	(3,072)	(1,832)
Repurchase of common stock	—	—	(1,431)
Purchase of subsidiary noncontrolling interests	(1,191)	—	—
Excess tax benefits	—	—	43
Balance at end of year	1,133,448	1,075,281	1,004,336
Accumulated Other Comprehensive Loss:			
Balance at beginning of year	(7,568)	(6,650)	(7,888)
Other comprehensive income (loss)	(522)	(918)	1,238
Balance at end of year	(8,090)	(7,568)	(6,650)
Retained Earnings:			
Balance at beginning of year	581,014	530,940	491,599
Net income attributable to Avista Corporation shareholders	115,916	137,228	123,227
Cash dividends paid (common stock)	(92,460)	(87,154)	(82,397)
Repurchase of common stock	—	—	(1,489)
Balance at end of year	604,470	581,014	530,940
Total Avista Corporation shareholders' equity	$ 1,729,828	$ 1,648,727	$ 1,528,626
Noncontrolling Interests:			
Balance at beginning of year	$ (251)	$ (339)	$ (429)
Net income attributable to noncontrolling interests	16	88	90
Purchase of subsidiary noncontrolling interests	891	—	—
Balance at end of year	656	(251)	(339)
Total equity	$ 1,730,484	$ 1,648,476	$ 1,528,287

The Accompanying Notes are an Integral Part of These Statements.

Notes to Consolidated Financial Statements

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista 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.

AERC is a wholly owned subsidiary of Avista Corp. The primary subsidiary of AERC is AEL&P, which comprises Avista Corp.'s regulated utility operations in Alaska.

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, which is a subsidiary of AERC. See Note 21 for business segment information.

On July 19, 2017, Avista Corp. entered into an Agreement and Plan of Merger (Merger Agreement) to become a wholly owned subsidiary of Hydro One. Consummation of the pending acquisition is subject to a number of approvals and the satisfaction or waiver of other specified conditions. The transaction is expected to close in the second half of 2018. See Note 4 for additional information.

Basis of Reporting

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries and other majority owned subsidiaries and variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. The amounts included in discontinued operations in the Consolidated Statements of Income for 2015 relate to the disposition of Ecova on June 30, 2014. See Note 5 for further information regarding the disposition of Ecova. Intercompany balances were eliminated in consolidation. The accompanying consolidated financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (see Note 7).

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported for assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include:

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

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

System of Accounts

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

Regulation

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

Utility Revenues

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

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

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

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

	2017	2016
Unbilled accounts receivable	$ 68,641	$ 72,377

Other Non-Utility Revenues

Revenues from the other businesses are primarily derived from the operations of AM&D, doing business as METALfx, and are recognized when the risk of loss transfers to the customer, which occurs when products are shipped. In addition, prior to Spokane Energy's dissolution in 2015, there were revenues at Spokane Energy related to a long-term fixed rate electric capacity contract. This contract was transferred to Avista Corp. during the second quarter of 2015 and the revenues from this contract subsequent to the transfer are included in utility revenues.

Depreciation

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

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

	2017	2016	2015
Avista Utilities			
Ratio of depreciation to average depreciable property	3.12%	3.11%	3.09%
Alaska Electric Light and Power Company			
Ratio of depreciation to average depreciable property	2.43%	2.39%	2.42%

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

	Avista Utilities	Alaska Electric Light and Power Company
Electric thermal/other production	41	41
Hydroelectric production	78	42
Electric transmission	57	41
Electric distribution	35	40
Natural gas distribution property	42	N/A
Other shorter-lived general plant	10	16

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 years ended December 31 (dollars in thousands):

	2017	2016	2015
Utility-related taxes	$ 64,012	$ 57,745	$ 59,173
Property taxes	40,074	38,505	35,948
Other taxes	2,666	2,485	2,536
Total	$ 106,752	$ 98,735	$ 97,657

Allowance for Funds Used During Construction

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

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

	2017	2016	2015
Avista Utilities			
Effective AFUDC rate	7.29%	7.29%	7.32%
Alaska Electric Light and Power Company			
Effective AFUDC rate	9.48%	9.40%	9.31%

Income Taxes

Deferred income tax assets represent future income tax deductions the Company expects to utilize in future tax returns to reduce taxable income. Deferred income tax liabilities represent future taxable income the Company expects to recognize in future tax returns. Deferred tax assets and liabilities arise when there are temporary differences resulting from differing treatment of items for tax and accounting purposes. A deferred income tax asset or liability is determined based on the enacted tax rates that will be in effect when the temporary differences between the financial statement carrying amounts and tax basis of existing assets and liabilities are expected to be reported in the Company's consolidated income tax returns. The deferred income tax expense for the period is equal to the net change in the deferred income tax asset and liability accounts from the beginning to the end of the period. The effect on deferred income taxes from a change in tax rates is recognized in income in the period that includes the enactment date unless a regulatory order specifies deferral of the effect of the change in tax rates over a longer period of time. The Company establishes a valuation allowance when it is more likely than not that all, or a portion, of a deferred tax asset will not be realized. Deferred income tax liabilities and regulatory assets are established for income tax benefits flowed through to customers.

The Company's largest deferred income tax item is the difference between the book and tax basis of utility plant. This item results from the temporary difference on depreciation expense. In early tax years, this item is recorded as a deferred income tax liability that will eventually reverse and become subject to income tax in later tax years.

See Note 11 for discussion of the TCJA and its impacts on the Company's financial statements during 2017, as well as a tabular presentation of all the Company's deferred tax assets and liabilities.

The Company did not incur any penalties on income tax positions in 2017, 2016 or 2015. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operating expense.

Stock-Based Compensation

The Company currently issues three types of stock-based compensation awards—restricted shares, market-based awards and performance-based awards. Historically, these stock compensation awards have not been material to the Company's overall financial results. Compensation cost relating to share-based payment transactions is recognized in the Company's financial statements based on the fair value of the equity or liability instruments issued and recorded over the requisite service period.

The Company recorded stock-based compensation expense (included in other operating expenses) and income tax benefits in the Consolidated Statements of Income of the following amounts for the years ended December 31 (dollars in thousands):

	2017	2016	2015
Stock-based compensation expense	$ 7,359	$ 7,891	$ 6,914
Income tax benefits [(1)]	2,576	2,762	2,420
Excess tax benefits on settled share-based employee payments [(2)]	2,348	1,597	—

(1) Income tax benefits were calculated using a 35 percent income tax rate; however, as of December 31, 2017, due to the TCJA enactment, deferred tax assets associated with stock compensation were revalued to 21 percent. Beginning on January 1, 2018 income tax benefits will be calculated using the new 21 percent tax rate.

(2) Beginning in 2016, excess tax benefits associated with the settlement of share-based employee payments are recognized in the Statements of Income due to the adoption of ASU 2016-09, effective January 1, 2016. See Note 2 for further discussion.

Restricted share awards vest in equal thirds each year over a three-year period and are payable in Avista Corp. common stock at the end of each year if the service condition is met. In addition to the service condition, the Company must meet a return on equity target in order for the Chief Executive Officer's restricted shares to vest. Restricted stock is valued at the close of market of the Company's common stock on the grant date.

Total Shareholder Return (TSR) awards are market-based awards and Cumulative Earnings Per Share (CEPS) awards are performance awards. CEPS awards were first granted in 2014. Both types of awards vest after a period of three years and are payable in cash or Avista Corp. common stock at the end of the three-year period. The method of settlement is at the discretion of the Company and historically the Company has settled these awards through issuance of Avista Corp. common stock and intends to continue this practice. Both types of awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific market or performance conditions. Based on the level of attainment of the market or performance conditions, the amount of cash paid or common stock issued will range from 0 to 200 percent of the initial awards granted. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest and have met the market and performance conditions.

For both the TSR awards and the CEPS awards, the Company accounts for them as equity awards and compensation cost for these awards is recognized over the requisite service period, provided that the requisite service period is rendered. For TSR awards, if the market condition is not met at the end of the three-year service period, there will be no change in the cumulative amount of compensation cost recognized, since the awards are still considered vested even though the market metric was not met. For CEPS awards, at the end of the three-year service period, if the internal performance metric of cumulative earnings per share is not met, all compensation cost for these awards is reversed as these awards are not considered vested.

The fair value of each TSR award is estimated on the date of grant using a statistical model that incorporates the probability of meeting the market targets based on historical returns relative to a peer group. The estimated fair value of the equity component of CEPS awards was estimated on the date of grant as the share price of Avista Corp. common stock on the date of grant, less the net present value of the estimated dividends over the three-year period.

The following table summarizes the number of grants, vested and unvested shares, earned shares (based on market metrics), and other pertinent information related to the Company's stock compensation awards for the years ended December 31:

	2017	2016	2015
Restricted Shares			
Shares granted during the year	57,746	58,610	58,302
Shares vested during the year	(57,473)	(52,385)	(60,379)
Unvested shares at end of year	106,053	109,806	106,091
Unrecognized compensation expense at end of year (in thousands)	$ 1,853	$ 1,853	$ 1,705
TSR Awards			
TSR shares granted during the year	114,390	116,435	116,435
TSR shares vested during the year	(107,649)	(111,665)	(171,334)
TSR shares earned based on market metrics	158,262	132,887	222,734
Unvested TSR shares at end of year	218,507	222,228	223,697
Unrecognized compensation expense (in thousands)	$ 2,849	$ 3,409	$ 3,219
CEPS Awards			
CEPS shares granted during the year	57,223	57,521	58,259
CEPS shares vested during the year	(53,862)	(55,835)	—
CEPS shares earned based on market metrics	41,502	90,460	—
Unvested CEPS shares at end of year	108,581	110,452	111,887
Unrecognized compensation expense (in thousands)	$ 1,856	$ 1,671	$ 1,840

Outstanding TSR and CEPS share awards include a dividend component that is paid in cash. This component of the share grants is accounted for as a liability award. These liability awards are revalued on a quarterly basis taking into account the number of awards outstanding, historical dividend rate, the change in the value of the Company's common stock relative to an external benchmark (TSR awards only) and the amount of CEPS earned to date compared to estimated CEPS over the performance period (CEPS awards only). Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2017 and 2016, the Company had recognized cumulative compensation expense and a liability of $1.5 million, respectively, related to the dividend component on the outstanding and unvested share grants.

Other Income—Net

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

	2017	2016	2015
Interest income	$ 2,162	$ 1,823	$ 653
Interest on regulatory deferrals	1,288	1,308	48
Equity-related AFUDC	6,669	8,475	8,331
Net loss on investments	(4,160)	(2,152)	(637)
Other income	1,104	624	905
Total	$ 7,063	$ 10,078	$ 9,300

Earnings per Common Share Attributable to Avista Corporation Shareholders

Basic earnings per common share attributable to Avista Corp. shareholders is computed by dividing net income attributable to Avista Corp. shareholders by the weighted-average number of common shares outstanding for the period. Diluted earnings per common share attributable to Avista Corp. shareholders is calculated by dividing net income attributable to Avista Corp. shareholders (adjusted for the effect of potentially dilutive securities issued to noncontrolling interests by the Company's subsidiaries) by diluted weighted-average common shares outstanding during the period, including common stock equivalent shares outstanding using the treasury stock method, unless such shares are anti-dilutive. Common stock equivalent shares include shares issuable upon exercise of stock options and contingent stock awards. See Note 18 for earnings per common share calculations.

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

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

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

	2017	2016	2015
Allowance as of the beginning of the year	$ 5,026	$ 4,530	$ 4,888
Additions expensed during the year	5,317	6,053	5,802
Net deductions	(5,211)	(5,557)	(6,160)
Allowance as of the end of the year	$ 5,132	$ 5,026	$ 4,530

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 market for our non-regulated operations and consisted of the following as of December 31 (dollars in thousands):

	2017	2016
Materials and supplies	$ 41,493	$ 40,700
Fuel stock	4,843	4,585
Stored natural gas	11,739	8,029
Total	$ 58,075	$ 53,314

Utility Plant in Service

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

Asset Retirement Obligations

The Company records the fair value of a liability for an ARO in the period in which it is incurred. When the liability is initially recorded, the associated costs of the ARO are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. In addition, if there are changes in the estimated timing or estimated costs of the AROs, adjustments are recorded during the period new information becomes available as an increase or decrease to the liability, with the offset recorded to the related long-lived asset. Upon retirement of the asset, the Company either settles the ARO for its recorded amount or recognizes a regulatory asset or liability for the difference, which will be surcharged/refunded to customers through the ratemaking process.

The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and AROs recorded since asset retirement costs are recovered through rates charged to customers (see Note 9 for further discussion of the Company's AROs).

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

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

	2017	2016
Regulatory liability for utility plant retirement costs	$ 285,786	$ 273,983

Goodwill

Goodwill arising from acquisitions represents the future economic benefit arising from other assets acquired in a business combination that are not individually identified and separately recognized. The Company evaluates goodwill for impairment using a qualitative analysis (Step 0) for AEL&P and a combination of discounted cash flow models and a market approach for the other subsidiaries on at least an annual basis or more frequently if impairment indicators arise. The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2017 and determined that goodwill was not impaired at that time. There were no events or circumstances that changed between November 30, 2017 and December 31, 2017 that would more likely than not reduce the fair values of the reporting units below their carrying amounts.

There were no changes in the carrying amount of goodwill during 2016 and 2017 and the balance was as follows (dollars in thousands):

	AEL&P	Other	Accumulated Impairment Losses	Total
Balance as of the December 31, 2016	$ 52,426	$ 12,979	$ (7,733)	$ 57,672
Balance as of the December 31, 2017	52,426	12,979	(7,733)	57,672

Accumulated impairment losses are attributable to the other businesses.

Derivative Assets and Liabilities

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

The WUTC and the 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. Realized benefits and costs result in adjustments to retail rates through PGAs, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases. The resulting regulatory assets have been concluded to be probable of 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, Avista Corp. records all mark-to-market gains and losses in each accounting period as assets and liabilities, as well as offsetting regulatory assets and liabilities, such that there is no income statement impact. The interest rate swap derivatives are risk management tools similar to energy commodity derivatives. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt. The Company records an offset of interest rate swap derivative assets and liabilities with regulatory assets and liabilities, based on the prior practice of the commissions to provide recovery through the ratemaking process. See Note 19 for additional discussion regarding interest rate swaps in the Company's 2017 Washington general rate cases.

As of December 31, 2017, 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). 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 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 Consolidated Balance Sheets. See Note 16 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits

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

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

Regulatory accounting practices require that certain costs and/or obligations (such as incurred power and natural gas costs not currently included in rates, but expected to be recovered or refunded in the future), are reflected as deferred charges or credits on the Consolidated Balance Sheets. These costs and/or obligations are not reflected in the Consolidated Statements of Income until the period during which matching revenues are recognized. The Company also has decoupling revenue deferrals. Decoupling revenue deferrals are recognized in the Consolidated Statements of Income during the period they occur (i.e. during the period of revenue shortfall or excess due to fluctuations in customer usage), subject to certain limitations, and a regulatory asset/liability is established which will be surcharged or rebated to customers in future periods. GAAP requires that for any alternative regulatory revenue program, like decoupling, the revenue must be expected to be collected from customers within 24 months of the deferral to qualify for recognition in the current period Consolidated Statement of Income. Any amounts included in the Company's decoupling program that are not expected to be collected from customers within 24 months are not recorded in the financial statements until the period in which revenue recognition criteria are met. This could ultimately result in decoupling revenue that arose during the current year being recognized in a future period.

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

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

See Note 20 for further details of regulatory assets and liabilities.

Unamortized Debt Expense

Unamortized debt expense includes debt issuance costs that are amortized over the life of the related debt. These costs are recorded as an offset to Long-Term Debt and Capital Leases on the Consolidated Balance Sheets.

Unamortized Debt Repurchase Costs

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

Accumulated Other Comprehensive Loss

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

	2017	2016
Unfunded benefit obligation for pensions and other postretirement benefit plans—net of taxes of $4,356 and $4,075, respectively	$ 8,090	$ 7,568

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

Details about Accumulated Other Comprehensive Loss Components	Amounts Reclassified from Accumulated Other Comprehensive Loss 2017	2016	2015	Affected Line Item in Statement of Income
Amortization of defined benefit pension items				
Amortization of net prior service cost	$ (4,381)	$ (1,171)	$ 31	[a]
Amortization of net loss	36,833	(7,602)	2,623	[a]
Adjustment due to effects of regulation [b]	(33,255)	7,360	(749)	[a]
	(803)	(1,413)	1,905	Total before tax
	281	495	(667)	Tax benefit (expense)
	$ (522)	$ (918)	$ 1,238	Net of tax

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

(b) The adjustment for the effects of regulation during the year ended December 31, 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.

Appropriated Retained Earnings

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

In addition to the hydroelectric project licenses identified above for Avista Utilities, the requirements of section 10(d) of the FPA also apply to the AEL&P licenses for Lake Dorothy and Annex Creek/Salmon Creek (combined).

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

	2017	2016
Appropriated retained earnings	$ 33,917	$ 25,564

Operating Leases

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from 1 to 45 years. Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year were not material as of December 31, 2017.

Capital Leases

The Company has two capital leases, one at Avista Corp. and one at AEL&P. The capital lease at Avista Corp. expires in 2018 and is not material to the financial statements as of December 31, 2017. The capital lease at AEL&P is a PPA (treated as a lease for accounting purposes) related to the Snettisham Hydroelectric Project that expires in 2034. While the two leases are treated as capital leases for accounting purposes, for ratemaking purposes these agreements are treated as operating leases with a constant level of annual rental expense (straight line expense). Because of this regulatory treatment, any difference between the operating lease expense for ratemaking purposes and the expenses recognized under capital lease treatment (interest and depreciation of the capital lease asset) is recorded as a regulatory asset and amortized during the later years of the lease when the capital lease expense is less than the operating lease expense included in base rates. See Note 14 for further discussion of the Snettisham capital lease.

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 loss contingencies that do not meet these conditions for accrual, if there is a reasonable possibility that a material loss may be incurred. As of December 31, 2017, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 19 for further discussion of the Company's commitments and contingencies.

NOTE 2. NEW ACCOUNTING STANDARDS

ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)"

In May 2014, the FASB issued ASU No. 2014-09, 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 should identify the various performance obligations in a contract, allocate the transaction price among the performance obligations and recognize revenue when (or as) the entity satisfies each performance obligation. This ASU is effective for periods beginning after December 15, 2017.

The Company will adopt this standard on January 1, 2018 using a modified retrospective method, which requires a cumulative adjustment to opening retained earnings, as opposed to a full retrospective application. The Company has not identified any cumulative adjustments.

Since the majority of Avista Corp.'s revenue is from rate-regulated sales of electricity and natural gas to retail customers and revenue is recognized as energy is delivered to these customers, the Company will not have a significant change in operating revenues or net income due to the application of this standard. The Company reviewed and analyzed certain contracts with customers (most of which are related to wholesale sales of power and natural gas) and did not identify any significant differences in revenue recognition between current GAAP and ASU No. 2014-09.

During the implementation process, the Company worked through several issues, the most significant of which are as follows:

Contributions in Aid of Construction—There was the potential that CIAC could be recognized as revenue upon the adoption of ASU No. 2014-09. Implementation guidance indicates that CIAC will continue to be accounted for as an offset to utility plant in service.

Utility-Related Taxes Collected from Customers—There were questions on the presentation of utility-related taxes collected from customers (primarily state excise taxes and city utility taxes) on a gross basis. Under GAAP, the Company has been allowed to record these utility-related taxes on a gross basis in revenue when billed to customers with an offset included in taxes other than income taxes in operating expenses. The Company evaluated whether this gross presentation is appropriate under ASU 2014-09 and determined that for AEL&P, the presentation will change from its current gross presentation to a net presentation with utility revenues and for Avista Utilities, the current presentation will not change. Currently, there are approximately $2.0 million annually in utility-related taxes collected from customers included in revenue for AEL&P.

Renewable Energy Credits—Utility industry implementation guidance indicates that revenue associated with the sale of self-generated RECs will be recognized at the time of generation and sale of the credits as opposed to when the RECs are certified in the Western Renewable Energy Generation Information System, which generally occurs during a period subsequent to the sale. This represents a change from the Company's prior practice, which has been to defer revenue recognition until the time of certification. Revenue associated with the sale of RECs is not material to the financial statements and almost all of the Company's REC revenue is deferred for future rebate to retail customers. As such, the change in the timing of revenue recognition will have an insignificant impact to revenue and net income.

The Company is monitoring utility industry implementation guidance to determine if there will be further industry consensus regarding accounting and presentation issues.

In addition to the issues described above, the Company will also have significant changes to its revenue-related footnote disclosures, including the bifurcation of wholesale revenue into derivative and non-derivative sales. The Company continues to evaluate what information would be most useful for users of the financial statements, including information already provided elsewhere in the document outside the footnote disclosures. These additional disclosures will most likely include the disaggregation of revenues by type of service, source of revenue or customer class. Also, the Company will have enhanced disclosures regarding its revenue recognition policies and elections. The Company does not expect any material presentation changes to the base financial statements, and only expects changes to its footnote disclosures.

ASU No. 2016-02, "Leases (Topic 842)"

In February 2016, the FASB issued ASU No. 2016-02. This ASU introduces a new lessee model that requires most leases to be capitalized and shown on the balance sheet with corresponding lease assets and liabilities. 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 issues that arise under the current lease 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. Under ASU 2016-02, upon adoption, the effects of this standard must be applied using a modified retrospective approach to the earliest period presented, which will likely require restatements of previously issued financial statements. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. During 2018, a proposed ASU was issued by the FASB that provides a practical expedient that would allow companies to use an optional transition method, which would allow for a cumulative adjustment to retained earnings during the period of adoption and prior periods would not require restatement.

The Company evaluated ASU 2016-02 and determined that it will not early adopt this standard before its effective date in 2019.

The Company has formed a lease standard implementation team that is working through the implementation process. Based on work to-date, the implementation team has identified a complete population of existing and potential leases under the new standard and has completed its review of the agreements associated with this population. However, the team has not yet quantified the impact of recording these leases. In addition, the team is developing a process to identify any new potential leases that may be entered into between now and the standard implementation date in 2019.

The Company is monitoring utility industry implementation guidance as it relates to several unresolved issues to determine if there will be an industry consensus. The Company has not yet estimated the potential impact on its future financial condition, results of operations and cash flows.

ASU No. 2016-09, "Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting"

In March 2016, the FASB issued ASU No. 2016-09. This ASU simplified 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 Consolidated Statements of Income rather than in Additional Paid in Capital (APIC),
- excess tax benefits no longer represent a financing cash inflow on the Consolidated Statements of Cash Flows and instead will be included as an operating activity,
- requiring excess tax benefits and tax deficiencies to be excluded from the calculation of diluted earnings per share, whereas under previous accounting guidance, these amounts had to 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.

The Company early adopted this standard during the second quarter of 2016, with a retrospective effective date of January 1, 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.

ASU No. 2017-07, "Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost"

In March 2017, the FASB issued ASU No. 2017-07, which amends the income statement presentation of the components of net periodic benefit cost for an entity's defined benefit pension and other postretirement plans. Under current GAAP, net benefit cost consists of several components that reflect different aspects of an employer's financial arrangements as well as the cost of benefits earned by employees. These components are aggregated and reported net in the financial statements. ASU No. 2017-07 requires entities to (1) disaggregate the current service-cost component from the other components of net benefit cost (other components) and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations.

In addition, only the service-cost component of net benefit cost is eligible for capitalization (e.g., as part of utility plant). This is a change from current practice, under which entities capitalize the aggregate net benefit cost to utility plant when applicable, in accordance with FERC accounting guidance. Avista Corp. is a rate-regulated entity and all components of net periodic benefit cost are currently recovered from customers as a component of utility plant and, under the new ASU, these costs will continue to be recovered from customers in the same manner over the depreciable lives of utility plant. As all such costs are expected to continue to be recoverable, the components that are no longer eligible to be recorded as a component of utility plant for GAAP will be recorded as regulatory assets.

This ASU is effective for periods beginning after December 15, 2017 and early adoption is permitted. Upon adoption, entities must use a retrospective transition method to adopt the requirement for separate presentation in the income statement and a prospective transition method to adopt the requirement to limit the capitalization of net periodic benefit costs to the service-cost component. The Company did not early adopt this standard and does not expect a material impact on its future financial condition, results of operations or cash flows upon adoption of this standard.

ASU 2018-02, "Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income"

In February 2018, the FASB issued ASU 2018-02, which amends the guidance for reporting comprehensive income. The ASU allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the enactment of the TCJA. This ASU is effective for periods beginning after December 15, 2018 and early adoption is permitted. Upon adoption, the requirements of the ASU must be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the TCJA is recognized. The Company did not early adopt this standard as of December 31, 2017 and does not expect a material impact on its future financial condition, results of operations or cash flows upon adoption of this standard.

NOTE 3. VARIABLE INTEREST ENTITIES

Lancaster Power Purchase Agreement

The Company has a PPA for the purchase of all the output of the Lancaster Plant, a 270 MW natural gas-fired combined cycle combustion turbine plant located in Kootenai County, Idaho, owned by an unrelated third-party (Rathdrum Power LLC), through 2026.

Avista Corp. has a variable interest in the PPA. Accordingly, Avista Corp. made an evaluation of which interest holders have the power to direct the activities that most significantly impact the economic performance of the entity and which interest holders have the obligation to absorb losses or receive benefits that could be significant to the entity. Avista Corp. pays a fixed capacity and operations and maintenance payment and certain monthly variable costs under the PPA. Under the terms of the PPA, Avista Corp. makes the dispatch decisions, provides all natural gas fuel and receives all of the electric energy output from the Lancaster Plant. However, Rathdrum Power LLC (the owner) controls the daily operation of the Lancaster Plant and makes operating and maintenance decisions. Rathdrum Power LLC controls all of the rights and obligations of the Lancaster Plant after the expiration of the PPA in 2026 and Avista Corp. does not have any further obligations after the expiration. It is estimated that the plant will have 15 to 25 years of useful life after that time. Rathdrum Power LLC bears the maintenance risk of the plant and will receive the residual value of the Lancaster Plant. Avista Corp. has no debt or equity investments in the Lancaster Plant and does not provide financial support through liquidity arrangements or other commitments (other than the PPA). Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Lancaster Plant. Accordingly, neither the Lancaster Plant nor Rathdrum Power LLC is included in Avista Corp.'s consolidated financial statements. The Company has a future contractual obligation of approximately $260.2 million under the PPA (representing the fixed capacity and operations and maintenance payments through 2026) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

Limited Partnerships and Similar Entities

Under current GAAP, a limited partnership or similar legal entity that is the functional equivalent of a limited partnership is considered a VIE regardless of whether it otherwise qualifies as a voting interest entity unless a simple majority or lower threshold of the "unrelated" limited partners (i.e., parties other than the general partner, entities under common control with the general partner, and other parties acting on behalf of the general partner) have substantive kick-out rights (including liquidation rights) or participating rights.

As of December 31, 2017, the Company has seven investments in limited partnerships (or the functional equivalent) where Avista Corp. is a limited partner investor in an investment fund where the general partner makes all of the investment and operating decisions with regards to the partnership and fund. To remove the general partner from any of the funds, approval from greater than a simple majority of the limited partners is required. As such, the limited partners do not have substantive kick-out rights and these investments are considered VIEs. Consolidation of these VIEs by Avista Corp. is not required because the Company does not have majority ownership in any of the funds, it does not have the power to direct any activities of the funds, and it does not have the power to appoint executive leadership, including the board of directors.

Avista Corp. participates in profits and losses of the investment funds based on its ownership percentage and its losses are capped at its total initial investment in the funds. For six of the seven VIEs, Avista Corp. does not have any additional commitments beyond its initial investment. For the seventh VIE, Avista Corp. has up to a $25.0 million total commitment, and as of December 31, 2017, has invested $9.7 million, leaving $15.3 million remaining to be invested. In addition, the Company is not allowed to withdraw any capital contributions from the investment funds until after the funds' expiration dates and all liabilities of the funds are settled. The expiration dates range from 2019 to 2037, with one investment having no termination date (as it is perpetual). In addition, two of the funds are closed and expired and the Company is awaiting distribution as soon as the underlying investments are liquidated. As of December 31, 2017, the Company has a total carrying amount in these investment funds of $12.2 million.

NOTE 4. PENDING ACQUISITION BY HYDRO ONE

On July 19, 2017, Avista Corp. entered into a Merger Agreement, by and among Hydro One, Olympus Holding Corp., a wholly owned subsidiary of Hydro One (US parent), and Olympus Corp., a wholly owned subsidiary of US parent (Merger Sub). Subject to the terms and conditions of the Merger Agreement, Merger Sub will be merged with and into Avista Corp., with Avista Corp. surviving as an indirect, wholly owned subsidiary of Hydro One. Hydro One, based in Toronto, is Ontario's largest electricity transmission and distribution provider.

At the effective time of the acquisition, each share of Avista Corp. common stock issued and outstanding, other than shares of Avista Corp. common stock that are owned by Hydro One, US Parent (as defined in the Merger Agreement) or Merger Sub or any of their respective subsidiaries, will be converted automatically into the right to receive an amount in cash equal to $53, without interest.

Closing Conditions, Required Approvals

Consummation of the acquisition is subject to the satisfaction or waiver, if permissible under applicable law, of specified closing conditions, including, but not limited to, (i) the approval of the acquisition by the holders of a majority of the outstanding shares of Avista Corp. Common Stock, (ii) the receipt of regulatory approvals required to consummate the acquisition, including approval from the FERC, the Committee on Foreign Investment in the United States (CFIUS), the Federal Communications Commission (FCC), the WUTC, IPUC, Public Service Commission of the State of Montana (MPSC), OPUC, and the RCA, and (iii) meeting the requirements of the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act), as amended. Under the HSR Act and the rules and regulations promulgated thereunder, the acquisition may not be completed until notification and report forms have been filed with the U.S. Department of Justice (DOJ) and the Federal Trade Commission (FTC) and the applicable waiting period has expired or been terminated. Hydro One and the Company each intend to file the required HSR notification and report forms with the DOJ and the FTC.

The transaction is expected to close in the second half of 2018 subject to remaining referenced approvals and the satisfaction or waiver of other specified conditions.

Approvals Requested

On September 14, 2017, Avista Corp. and Hydro One filed applications for approval of the acquisition with the FERC, the WUTC, the IPUC, the OPUC and the MPSC, requesting approval of the transaction on or before August 14, 2018. However, the OPUC has set a procedural schedule with an end date no later than September 14, 2018. On November 21, 2017, applications for approval of the acquisition were filed with the RCA, with a statutory deadline of May 20, 2018.

On February 9, 2018, Hydro One and the Company filed a draft joint voluntary notice of the acquisition with CFIUS pursuant to Section 721 of Title VII of the Defense Production Act of 1950, as amended, 50 U.S.C. § 4565 (Section 721) and its implementing regulations.

Approvals Received

On November 21, 2017, Avista Corp. shareholders approved the acquisition in a special meeting of shareholders. Also, on January 16, 2018 the FERC approved the acquisition.

Other Pending Required Approvals

The Company intends to file for the required approvals with the FCC pursuant to Section 310 of the Communications Act of 1934, as amended, over the transfer of control of FCC licenses that would result from the acquisition.

Other Information Related to the Acquisition

As part of the applications for approval, Hydro One and Avista Corp. have proposed to flow through to Avista Corp.'s retail customers in each of Washington, Idaho and Oregon rate credits, which amount to $31.5 million in total among the three jurisdictions, over a 10-year period beginning at the time the acquisition closes. In addition, to the extent Avista Corp. and Hydro One in a future rate proceeding demonstrate that cost savings, or benefits, directly related to the proposed transaction are already being flowed through to customers through base retail rates, the rate credit to customers would be reduced by up to $22.0 million over the 10-year period. The portion of the total rate credit that is not allowable for offset effectively represents acceptance by Hydro One of a lower rate of return during the 10-year period.

As part of the reply comments that were included in the application for approval that was filed with the RCA, Hydro One and Avista Corp. have proposed to flow through to AEL&P's customers, a rate credit totaling $1.0 million over a 10-year period beginning at the time the acquisition closes.

The Merger Agreement also contains customary representations, warranties and covenants of Avista Corp., Hydro One, US Parent and Merger Sub. These covenants include, among others, an obligation on behalf of Avista Corp. to operate its business in the ordinary course until the acquisition is consummated, subject to certain exceptions. In addition, the parties are required to use reasonable best efforts to obtain any required regulatory approvals.

Avista Corp. has made certain additional customary covenants, including, among others, and subject to certain exceptions, a customary non-solicitation covenant prohibiting Avista Corp. from soliciting, providing non-public information or entering into discussions or negotiations concerning proposals relating to alternative business combination transactions, except as and to the extent permitted under the Merger Agreement with respect to an unsolicited written Takeover Proposal (as defined in the Merger Agreement) made prior to the approval of the acquisition by Avista Corp.'s shareholders if, among other things, Avista Corp.'s board of directors determines in good faith that such Takeover Proposal is or could be reasonably expected to lead to a Superior Proposal (as defined in the Merger Agreement) and that failure to take such actions would reasonably be expected to be inconsistent with its fiduciary duties under applicable law. No such Takeover Proposals have been received.

The Merger Agreement may be terminated by Avista Corp. and Hydro One by mutual consent and by either Avista Corp. or Hydro One under certain circumstances, including if the acquisition is not consummated by September 30, 2018 (subject to an extension of up to six months by either party if all of the conditions to closing, other than the conditions related to obtaining required regulatory approvals, the absence of a law or injunction preventing the consummation of the acquisition and the absence of a Burdensome Condition (as defined in the Merger Agreement) in any required regulatory approval, have been satisfied). The Merger Agreement also provides for certain additional termination rights for each of Avista Corp. and Hydro One. Upon termination of the Merger Agreement under certain specified circumstances, including (i) termination by Avista Corp. in order to enter into a definitive agreement with respect to a Superior Proposal, or (ii) termination by Hydro One following a withdrawal by Avista Corp.'s board or directors of its recommendation of the Merger Agreement, Avista Corp. will be required to pay Hydro One the Company Termination Fee of $103.0 million. Avista Corp. will also be required to pay Hydro One the Company Termination Fee in the event Avista Corp. signs or consummates any specified alternative transaction within twelve months following the termination of the Merger Agreement under certain circumstances. In addition, if the Merger Agreement is terminated under certain circumstances due to the failure to obtain required regulatory approvals, the imposition of a Burdensome Condition with respect to a required regulatory approval, or the breach by Hydro One, US Parent or Merger Sub of their obligations in respect of obtaining regulatory approvals, Hydro One will be required to pay Avista Corp. a termination fee of $103.0 million.

The Company is incurring significant acquisition costs associated with the pending Hydro One acquisition consisting primarily of consulting, banking fees, legal fees and employee time and are not being passed through to customers. In addition, a significant portion of these costs are not deductible for income tax purposes.

See Note 19 for discussion of shareholder lawsuits filed against the Company, the Company's directors, Hydro One, Olympus Holding Corp., and Olympus Corp. in relation to the Merger Agreement and the proposed acquisition.

NOTE 5. DISCONTINUED OPERATIONS

On June 30, 2014, Avista Capital, completed the sale of its interest in Ecova to Cofely USA Inc., 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 all the security holders of Ecova pro rata based on ownership. 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. There were no amounts recorded for discontinued operations during the years ended December 31, 2017 and 2016.

The following table presents amounts that were included in discontinued operations for the year ended December 31, 2015 (dollars in thousands):

	2015
Revenues	$ —
Gain on sale of Ecova [1]	777
Transaction expenses and accelerated employee benefits	71
Gain on sale of Ecova—net of transaction expenses	706
Income before income taxes	706
Income tax benefit [2]	(4,441)
Net income from discontinued operations	5,147
Net income attributable to noncontrolling interests	—
Net income from discontinued operations attributable to Avista Corp. shareholders	$ 5,147

(1) This represents the gross gain recorded to discontinued operations. The total gain net of taxes and transactions expenses was $74.8 million, of which $69.7 million was recognized during 2014.

(2) The tax benefit during 2015 primarily resulted from the reversal of a valuation allowance against net operating losses at Ecova because the net operating losses were deemed realizable after further evaluation.

NOTE 6. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. 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 Corp. utilizes derivative instruments, such as forwards, futures, swap derivatives and options in order to manage the various risks relating to these commodity price exposures. Avista Corp. has an energy resources risk policy and control procedures to manage these risks.

As part of Avista Corp.'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 Avista Corp.'s load obligations and the use of these resources to capture available economic value through wholesale market transactions. These include sales and purchases of 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 Corp. 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 Corp.'s distribution system. However, daily variations in natural gas demand can be significantly different than monthly demand projections. On the basis of these projections, Avista Corp. 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 Corp. also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets.

Avista Corp. plans for sufficient natural gas delivery capacity to serve its retail customers for a theoretical peak day event. Avista Corp. generally has more pipeline and storage capacity than what is needed during periods other than a peak day. Avista Corp. optimizes its natural gas resources by using market opportunities to generate economic value that helps mitigate fixed costs. Avista Corp. 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 Avista Corp. should buy or sell natural gas during other times in the year, Avista Corp. 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 December 31, 2017 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	
	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
Year	MWh	MWh	mmBTUs	mmBTUs	MWh	MWh	mmBTUs	mmBTUs
2018	426	763	10,572	107,580	213	1,739	3,643	67,375
2019	235	737	610	61,073	94	1,420	1,345	35,438
2020	—	—	910	16,590	—	589	1,430	915
2021	—	—	—	—	—	—	1,049	—
2022	—	—	—	—	—	—	—	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents the underlying energy commodity derivative volumes as of December 31, 2016 that were expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
Year	MWh	MWh	mmBTUs	mmBTUs	MWh	MWh	mmBTUs	mmBTUs
2017	510	907	15,475	110,380	316	1,552	4,165	73,110
2018	397	—	—	52,755	286	1,244	1,360	15,113
2019	235	—	610	29,475	158	982	1,345	4,020
2020	—	—	910	2,725	—	—	1,430	—
2021	—	—	—	—	—	—	1,060	—
Thereafter	—	—	—	—	—	—	—	—

(1) Physical transactions represent commodity transactions in which Avista Corp. 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, swap derivatives, 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 deferral and recovery mechanisms (ERM, PCA, and PGAs), or in the general rate case process, and are expected to be collected through retail rates from customers.

Foreign Currency Exchange Derivatives

A significant portion of Avista Corp.'s 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 Corp.'s 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 Corp. hedges a portion of the foreign currency risk by purchasing Canadian currency exchange 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 Avista Corp.'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 exchange derivatives that Avista Corp. has outstanding as of December 31 (dollars in thousands):

	2017	2016
Number of contracts	18	21
Notional amount (in United States dollars)	$ 2,552	$ 2,819
Notional amount (in Canadian dollars)	3,241	3,754

Interest Rate Swap Derivatives

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt, and future borrowing requirements. Avista Corp. hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swap derivatives and U.S. Treasury lock agreements. These interest rate swap derivatives 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 unsettled interest rate swap derivatives that Avista Corp. has outstanding as of the balance sheet date indicated below (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
December 31, 2017	14	275,000	2018
	6	70,000	2019
	3	30,000	2020
	1	15,000	2021
	5	60,000	2022
December 31, 2016	6	75,000	2017
	14	275,000	2018
	6	70,000	2019
	2	20,000	2020
	5	60,000	2022

During the third quarter 2017, in connection with the execution of a purchase agreement for $90.0 million of Avista Corp. first mortgage bonds issued in December 2017, Avista Corp. cash-settled five interest rate swap derivatives (notional aggregate amount of $60.0 million) and paid a total of $8.8 million. Upon settlement of interest rate swap derivatives, the cash payments made or received are recorded as a regulatory asset or liability and are subsequently amortized as a component of interest expense over the life of the associated debt. The settled interest rate swap derivatives are also included as a part of Avista Corp.'s cost of debt calculation for ratemaking purposes.

The fair value of outstanding interest rate swap derivatives can vary significantly from period to period depending on the total notional amount of swap derivatives outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. Avista Corp. is required to make cash payments to settle the interest rate swap derivatives when the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, Avista Corp. receives cash to settle its interest rate swap derivatives when prevailing market rates at the time of settlement exceed the fixed swap rates.

Summary of Outstanding Derivative Instruments

The amounts recorded on the Consolidated Balance Sheet as of December 31, 2017 and December 31, 2016 reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of derivative instruments recorded on the Consolidated Balance Sheet as of December 31, 2017 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet
Foreign currency exchange derivatives				
Other current assets	$ 32	$ (1)	$ —	$ 31
Interest rate swap derivatives				
Other current assets	2,597	(270)	—	2,327
Other property and investments—net and other non-current assets	4,880	(2,304)	—	2,576
Current unsettled interest rate swap derivative liabilities	—	(63,399)	28,952	(34,447)
Non-current interest rate swap derivative liabilities	—	(7,540)	6,018	(1,522)
Energy commodity derivatives				
Other current assets	1,386	(122)	—	1,264
Current energy commodity derivative liabilities	26,641	(52,895)	17,406	(8,848)
Other non-current liabilities, regulatory liabilities and deferred credits	15,970	(34,936)	10,032	(8,934)
Total derivative instruments recorded on the balance sheet	$ 51,506	$ (161,467)	$ 62,408	$ (47,553)

The following table presents the fair values and locations of derivative instruments recorded on the Consolidated Balance Sheet as of December 31, 2016 (in thousands):

Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Fair Value Net Asset (Liability) in Balance Sheet
Foreign currency exchange derivatives				
Other current liabilities	$ 5	$ (28)	$ —	$ (23)
Interest rate swap derivatives				
Other current assets	3,393	—	—	3,393
Other property and investments—net and other non-current assets	5,754	(397)	—	5,357
Current unsettled interest rate swap derivative liabilities	—	(15,756)	9,731	(6,025)
Non-current interest rate swap derivative liabilities	3,951	(57,825)	25,169	(28,705)
Energy commodity derivatives				
Other current assets	18,682	(16,787)	—	1,895
Current energy commodity derivative liabilities	16,335	(29,598)	6,228	(7,035)
Other non-current liabilities, regulatory liabilities and deferred credits	13,071	(29,990)	3,630	(13,289)
Total derivative instruments recorded on the balance sheet	$ 61,191	$ (150,381)	$ 44,758	$ (44,432)

Exposure to Demands for Collateral

Avista Corp.'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 Avista Corp.'s credit ratings or changes in market prices, additional collateral may be required. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against Avista Corp.'s credit facilities and cash. Avista Corp. actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements.

The following table presents Avista Corp.'s collateral outstanding related to its derivative instruments as of as of December 31 (in thousands):

	2017	2016
Energy commodity derivatives		
Cash collateral posted	$ 39,458	$ 17,134
Letters of credit outstanding	23,000	24,400
Balance sheet offsetting (cash collateral against net derivative positions)	27,438	9,858
Interest rate swap derivatives		
Cash collateral posted	34,970	34,900
Letters of credit outstanding	5,000	3,600
Balance sheet offsetting (cash collateral against net derivative positions)	34,970	34,900

Certain of Avista Corp.'s derivative instruments contain provisions that require the Company to maintain an "investment grade" credit rating from the major credit rating agencies. If Avista Corp.'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 Avista Corp. could be required to post as of December 31 (in thousands):

	2017	2016
Energy commodity derivatives		
Liabilities with credit-risk-related contingent features	$ 1,336	$ 1,124
Additional collateral to post	1,336	1,046
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	73,514	73,978
Additional collateral to post	18,770	21,100

NOTE 7. JOINTLY OWNED ELECTRIC FACILITIES

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

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

	2017	2016
Utility plant in service	$ 379,970	$ 380,406
Accumulated depreciation	(255,604)	(249,359)

See Note 9 for further discussion of AROs.

NOTE 8. PROPERTY, PLANT AND EQUIPMENT

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

	2017	2016
Avista Utilities:		
Electric production	$ 1,392,017	$ 1,346,332
Electric transmission	726,240	682,529
Electric distribution	1,617,451	1,525,175
Electric construction work-in-progress (CWIP) and other	322,144	296,912
Electric total	4,057,852	3,850,948
Natural gas underground storage	46,233	44,672
Natural gas distribution	1,027,197	954,298
Natural gas CWIP and other	63,803	57,601
Natural gas total	1,137,233	1,056,571
Common plant (including CWIP)	588,833	527,458
Total Avista Utilities	5,783,918	5,434,977
AEL&P:		
Electric production	97,883	94,839
Electric transmission	21,413	20,252
Electric distribution	21,061	20,057
Electric production held under long-term capital lease	71,007	71,007
Electric CWIP and other	7,341	7,190
Electric total	218,705	213,345
Common plant	8,524	8,651
Total AEL&P	227,229	221,996
Other (1)	36,783	30,764
Total	$ 6,047,930	$ 5,687,737

(1) Included in other property and investments—net and other non-current assets on the Consolidated Balance Sheets. Accumulated depreciation was $11.6 million as of December 31, 2017 and $11.2 million as of December 31, 2016 for the other businesses.

NOTE 9. ASSET RETIREMENT OBLIGATIONS

The Company has recorded liabilities for future AROs to:

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

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

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

In 2015, the EPA issued a final rule regarding coal combustion residuals (CCR), also termed coal combustion byproducts or coal ash. Colstrip, of which Avista Corp. is a 15 percent owner of units 3 & 4, produces this byproduct. The rule established technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste. The Company, in conjunction with the other Colstrip owners, developed a multi-year compliance plan to strategically address the CCR requirements and existing state obligations while maintaining operational stability. During 2015, the operator of Colstrip provided an initial cost estimate of the expected retirement costs associated with complying with the new CCR rule. Based on the initial assessments, Avista Corp. recorded an increase to its ARO of $12.5 million during 2015 with a corresponding increase in the cost basis of the utility plant. During 2016 and 2017, due to additional information and updated estimates, the ARO was adjusted during each of those years by minor amounts.

The actual asset retirement costs related to the CCR rule requirements may vary substantially from the estimates used to record the ARO due to the uncertainty and evolving nature of the compliance strategies that will be used and the availability of data used to estimate costs, such as the quantity of coal ash present at certain sites and the volume of fill that will be needed to cap and cover certain impoundments. Avista Corp. will coordinate with the plant operator and continue to gather additional data in future periods to make decisions about compliance strategies and the timing of closure activities. As additional information becomes available, Avista Corp. will update the ARO for these changes in estimates, which could be material. The Company expects to seek recovery of any increased costs related to complying with the CCR rule through customer rates.

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

	2017	2016	2015
Asset retirement obligation at beginning of year	$ 15,515	$ 15,997	$ 3,028
Liabilities incurred	1,171	430	12,539
Liabilities settled	—	(1,529)	(29)
Accretion expense	796	617	459
Asset retirement obligation at end of year	$ 17,482	$ 15,515	$ 15,997

NOTE 10. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The pension and other postretirement benefit plans described below only relate to Avista Utilities. AEL&P (not discussed below) participates in a defined contribution multiemployer plan for its union workers and a defined contribution money purchase pension plan for its nonunion workers. METALfx (not discussed below) has a defined contribution 401(k) savings plan. None of the subsidiary retirement plans, individually or in the aggregate, are significant to Avista Corp.

Avista Utilities

The Company has a defined benefit pension plan covering the majority of all regular full-time employees at Avista Utilities that were hired prior to January 1, 2014. Individual benefits under this plan are based upon the employee's years of service, date of hire and average compensation as specified in the plan. Non-union employees hired on or after January 1, 2014 participate in a defined contribution 401(k) plan in lieu of a defined benefit pension plan. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $22.0 million in cash to the pension plan in 2017, $12.0 million in 2016 and $12.0 million in 2015. The Company expects to contribute $22.0 million in cash to the pension plan in 2018.

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

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

	2018	2019	2020	2021	2022	Total 2023–2027
Expected benefit payments	$ 36,916	$ 37,613	$ 38,610	$ 38,729	$ 38,837	$ 205,395

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

The Company provides certain health care and life insurance benefits for eligible retired employees that were hired prior to January 1, 2014. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The liability and expense of this plan are included as other postretirement benefits. Non-union employees hired on or after January 1, 2014, will have access to the retiree medical plan upon retirement; however, Avista Corp. will no longer provide a contribution toward their medical premium.

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

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

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

	2018	2019	2020	2021	2022	Total 2023–2027
Expected benefit payments	$ 6,856	$ 7,064	$ 6,093	$ 6,223	$ 6,288	$ 32,265

The Company expects to contribute $6.9 million to other postretirement benefit plans in 2018, representing expected benefit payments to be paid during the year excluding the Medicare Part D subsidy. The Company uses a December 31 measurement date for its pension and other postretirement benefit plans.

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2017 and 2016 and the components of net periodic benefit costs for the years ended December 31, 2017, 2016 and 2015 (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	2017	2016
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 666,472	$ 613,503	$ 136,453	$ 138,795
Service cost	20,406	18,302	3,220	3,205
Interest cost	27,898	27,544	5,490	6,110
Actuarial (gain)/loss	39,743	39,997	(6,020)	(3,648)
Plan change	3,158	—	—	—
Cumulative adjustment to reclassify liability	—	—	—	(1,042)
Benefits paid	(41,116)	(32,874)	(6,196)	(6,967)
Benefit obligation as of end of year	$ 716,561	$ 666,472	$ 132,947	$ 136,453
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 540,914	$ 517,234	$ 33,365	$ 30,868
Actual return on plan assets	82,476	43,212	4,588	2,497
Employer contributions	22,000	12,000	—	—
Benefits paid	(39,738)	(31,532)	—	—
Fair value of plan assets as of end of year	$ 605,652	$ 540,914	$ 37,953	$ 33,365
Funded status	$ (110,909)	$ (125,558)	$ (94,994)	$ (103,088)
Unrecognized net actuarial loss	157,883	178,783	68,280	81,979
Unrecognized prior service cost	3,179	23	(7,782)	(8,981)
Prepaid (accrued) benefit cost	50,153	53,248	(34,496)	(30,090)
Additional liability	(161,062)	(178,806)	(60,498)	(72,998)
Accrued benefit liability	$ (110,909)	$ (125,558)	$ (94,994)	$ (103,088)
Accumulated pension benefit obligation	$ 624,345	$ 583,498	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 60,354	$ 60,670
For fully eligible employees			$ 32,891	$ 34,429
For other participants			$ 39,702	$ 41,354
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost	$ 2,066	$ 15	$ (5,058)	$ (5,854)
Unrecognized net actuarial loss	102,624	116,209	44,382	53,303
Total	104,690	116,224	39,324	47,449
Less regulatory asset	(97,025)	(108,903)	(38,899)	(47,202)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 7,665	$ 7,321	$ 425	$ 247
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	3.71%	4.26%	3.72%	4.23%
Discount rate for annual expense	4.26%	4.57%	4.23%	4.57%
Expected long-term return on plan assets	5.87%	5.40%	5.69%	6.03%
Rate of compensation increase	4.69%	4.78%		
Medical cost trend pre-age 65—initial			6.50%	7.00%
Medical cost trend pre-age 65—ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2023	2023
Medical cost trend post-age 65—initial			6.50%	7.00%
Medical cost trend post-age 65—ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2024	2024

	Pension Benefits			Other Postretirement Benefits		
	2017	2016	2015	2017	2016	2015
Components of net periodic benefit cost:						
Service cost	$ 20,406	$ 18,302	$ 19,791	$ 3,220	$ 3,205	$ 2,925
Interest cost	27,898	27,544	26,117	5,490	6,110	5,158
Expected return on plan assets	(31,626)	(27,547)	(28,299)	(1,899)	(1,861)	(1,991)
Amortization of prior service cost	2	2	2	(1,144)	(1,208)	(1,199)
Net loss recognition	9,793	8,511	9,451	4,934	5,728	5,095
Net periodic benefit cost	$ 26,473	$ 26,812	$ 27,062	$ 10,601	$ 11,974	$ 9,988

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase the accumulated postretirement benefit obligation as of December 31, 2017 by $6.6 million and the service and interest cost by $0.8 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease the accumulated postretirement benefit obligation as of December 31, 2017 by $5.2 million and the service and interest cost by $0.6 million.

Plan Assets

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

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

Pension plan assets are invested in mutual funds, trusts and partnerships that hold marketable debt and equity securities, real estate, absolute return and commodity funds. In seeking to obtain a return that aligns with the funded status of the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee. The Finance Committee has established target investment allocation percentages by asset classes and also investment ranges for each asset class. The target investment allocation percentages are typically the midpoint of the established range.

The target investment allocation percentages by asset classes are indicated in the table below:

	2017	2016
Equity securities	37%	37%
Debt securities	45%	45%
Real estate	8%	8%
Absolute return	10%	10%

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

Pension plan and other postretirement plan assets whose fair values are measured using net asset value (NAV) are excluded from the fair value hierarchy and are included as reconciling items in the tables below.

Investments in common/collective trust funds are presented at estimated fair value, which is determined based on the unit value of the fund. Unit value is determined by an independent trustee, which sponsors the fund, by dividing the fund's net assets by its units outstanding at the valuation date. The Company's investments in common/collective trusts have redemption limitations that permit quarterly redemptions following notice requirements of 45 to 60 days. The fair values of the closely held investments and partnership interests are based upon the allocated share of the fair value of the underlying net assets as well as the allocated share of the undistributed profits and losses, including realized and unrealized gains and losses. Most of the Company's investments in closely held investments and partnership interests have redemption limitations that range from bi-monthly to semi-annually following redemption notice requirements of 60 to 90 days. One investment in a partnership has a lock-up for redemption currently expiring in 2022 and is subject to extension.

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

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

The fair value of pension plan assets was determined as of December 31, 2017 and 2016.

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2017 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 20,619	$ —	$ 20,619
Fixed income securities:				
U.S. government issues	—	20,305	—	20,305
Corporate issues	—	185,272	—	185,272
International issues	—	32,054	—	32,054
Municipal issues	—	20,201	—	20,201
Mutual funds:				
U.S. equity securities	127,742	—	—	127,742
International equity securities	40,755	—	—	40,755
Absolute return (1)	7,728	—	—	7,728
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	34,470
International equity securities	—	—	—	43,462
Partnership/closely held investments:				
Absolute return (1)	—	—	—	67,167
Private equity funds (2)	—	—	—	72
Real estate	—	—	—	5,805
Total	$ 176,225	$ 278,451	$ —	$ 605,652

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2016 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 10,179	$ —	$ 10,179
Fixed income securities:				
U.S. government issues	—	30,919	—	30,919
Corporate issues	—	193,563	—	193,563
International issues	—	34,145	—	34,145
Municipal issues	—	18,888	—	18,888
Mutual funds:				
U.S. equity securities	120,856	—	—	120,856
International equity securities	30,025	—	—	30,025
Absolute return (1)	6,622	—	—	6,622
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	19,779
International equity securities	—	—	—	29,140
Partnership/closely held investments:				
Absolute return (1)	—	—	—	39,077
Private equity funds (2)	—	—	—	72
Real estate	—	—	—	7,649
Total	$ 157,503	$ 287,694	$ —	$ 540,914

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

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

The fair value of other postretirement plan assets invested in debt and equity securities was based primarily on market prices. The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). The target asset allocation was 60 percent equity securities and 40 percent debt securities in both 2017 and 2016.

The fair value of other postretirement plan assets was determined as of December 31, 2017 and 2016.

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2017 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Balanced index mutual funds [1]	$ 37,953	$ —	$ —	$ 37,953

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2016 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 6	$ —	$ 6
Balanced index mutual funds [1]	33,359	—	—	33,359
Total	$ 33,359	$ 6	$ —	$ 33,365

(1) The balanced index fund for 2017 and 2016 is a single mutual fund that includes a percentage of U.S. equity and fixed income securities and International equity and fixed income securities.

401(k) Plans and Executive Deferral Plan

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

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

	2017	2016	2015
Employer 401(k) matching contributions	$ 9,075	$ 8,710	$ 8,011

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

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

	2017	2016
Deferred compensation assets and liabilities	$ 8,458	$ 7,679

NOTE 11. ACCOUNTING FOR INCOME TAXES

Federal Income Tax Law Changes

On December 22, 2017, the TCJA was signed into law. The legislation includes substantial changes to the taxation of individuals as well as U.S. businesses, multi-national enterprises, and other types of taxpayers. Highlights of provisions most relevant to Avista Corp. include:

- A permanent reduction in the statutory corporate tax rate from 35 percent to 21 percent, beginning with tax years after 2017;
- Statutory provisions requiring that excess deferred taxes associated with public utility property be normalized using the ARAM for determining the timing of the return of excess deferred taxes to customers. Excess deferred taxes result from revaluing deferred tax assets and liabilities based on the newly enacted tax rate instead of the previous tax rate, which, for most rate-regulated utilities like Avista Utilities and AEL&P, results in a net benefit to customers that will be deferred as a regulatory liability and passed through to customers over future periods;
- Repeal of the corporate AMT;
- Bonus depreciation (expensing of capital investment on an accelerated basis) was removed as a deduction for property predominantly used in certain rate-regulated businesses (like Avista Utilities and AEL&P), but is still allowed for the Company's non-regulated businesses;
- The deduction for interest expense that is properly allocable to certain rate-regulated trade or businesses is still allowed under the new law, but the deduction is now limited for the Company's non-regulated businesses; and
- NOL carryback deductions were eliminated, but carryforward deductions are allowed indefinitely with some annual limitations versus the previous 20-year limitation.

The Company's analysis and interpretation of this legislation is complete as it relates to amounts recorded as of December 31, 2017 and based on its evaluation, the reduction of the U.S. corporate income tax rate required a revaluation of the Company's deferred income tax assets and liabilities (including the value of our net operating loss carryforwards) during the fourth quarter of 2017, the period in which the tax legislation was enacted. Because Avista Corp. is predominantly a rate-regulated entity, a large portion of the net effect of the legislation was recorded as a regulatory liability on the Consolidated Balance Sheets and it will be returned to customers through the ratemaking process in future periods. The total net amount of the regulatory liability associated with the TCJA was $442.3 million as of December 31, 2017, which is made up of $339.9 million in excess deferred taxes and $102.4 million for the income tax gross-up of those excess deferred taxes (which, together with the excess deferred tax amount, reflects the revenue amounts to be refunded to customers through the regulatory process). The Company expects the Avista Utilities plant related amounts will be returned to customers over a period of approximately 36 years using the ARAM. The Company expects the AEL&P plant related amounts to be returned to customers over a period of approximately 40 years. The Company does not currently have an estimate for the amortization period for the regulatory liability attributable to non-plant excess deferred taxes items as the Company is waiting for additional implementation guidance from various regulatory agencies.

Because the Company has deferred income tax assets and liabilities related to its unregulated subsidiaries and certain utility expenses which are not being passed through to customers, the impact of the revaluation of the Company's deferred income tax assets and liabilities was recorded as a $10.2 million (net) discrete adjustment to income tax expense in the fourth quarter of 2017. Of this income tax expense amount, $7.5 million related to Avista Utilities and $2.7 million related to the other businesses.

Because most of the provisions of the TCJA are effective as of January 1, 2018 (including a reduction of the income tax rate to 21 percent), but the Company's customers' rates continue to have the 35 percent corporate tax rate built in from prior general rate cases, the Company filed Petitions in January 2018 with the WUTC and OPUC requesting orders authorizing the deferral of the accounting impact of the change in federal income tax expense caused by the enactment of the TCJA (the IPUC on its own ordered deferred accounting for all jurisdictional utilities in January 2018). The Company is requesting to defer the impact of the change in federal income tax expense beginning in January 2018 forward until all benefits are properly captured through the deferral and refunded to customers through tariffs to be reviewed and implemented in future rate proceedings. The IPUC has requested a report on the estimated overall benefit to customers related to the impacts of the TCJA by March 30, 2018. The WUTC has issued a bench request in the Company's 2017 electric and natural gas general rate cases requesting such information by February 28, 2018.

Income Tax Expense

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

	2017	2016	2015
Current income tax expense (benefit)	$ 13,101	$ (46,457)	$ 12,212
Deferred income tax expense	69,657	124,543	55,237
Total income tax expense	$ 82,758	$ 78,086	$ 67,449

State income taxes do not represent a significant portion of total income tax expense on the Consolidated Statements of Income for any periods presented.

A reconciliation of federal income taxes derived from statutory federal tax rates (35 percent in 2017, 2016 and 2015) applied to income before income taxes as set forth in the accompanying Consolidated Statements of Income is as follows for the years ended December 31 (dollars in thousands):

	2017		2016		2015	
Federal income taxes at statutory rates	$ 69,542	35.0%	$ 75,391	35.0%	$ 64,967	35.0%
Increase (decrease) in tax resulting from:						
Tax effect of regulatory treatment of utility plant differences	3,482	1.7	3,297	1.5	4,358	2.3
State income tax expense	1,110	0.6	1,316	0.6	1,012	0.5
Settlement of prior year tax returns and adjustment of tax reserves	(384)	(0.2)	13	—	(992)	(0.5)
Manufacturing deduction	(1,119)	(0.6)	—	—	(1,198)	(0.6)
Settlement of equity awards	(1,439)	(0.7)	(1,597)	(0.7)	—	—
Acquisition costs	2,491	1.3	—	—	—	—
Federal income tax rate change	10,169	5.1	—	—	—	—
Other	(1,094)	(0.5)	(334)	(0.1)	(698)	(0.4)
Total income tax expense	$ 82,758	41.7%	$ 78,086	36.3%	$ 67,449	36.3%

Deferred Income Taxes

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

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

	2017	2016
Deferred income tax assets:		
Unfunded benefit obligation	$ 41,944	$ 80,230
Utility energy commodity and interest rate swap derivatives	23,364	31,872
Regulatory deferred tax credits	6,359	15,192
Tax credits	23,042	27,931
Power and natural gas deferrals	14,379	19,415
Deferred compensation	7,080	11,141
Deferred taxes on regulatory liabilities	105,508	6,604
Other	15,892	22,908
Total gross deferred income tax assets	237,568	215,293
Valuation allowances for deferred tax assets	(10,982)	(7,946)
Total deferred income tax assets after valuation allowances	226,586	207,347
Deferred income tax liabilities:		
Differences between book and tax basis of utility plant	494,783	812,916
Regulatory asset on utility, property plant and equipment	81,860	37,301
Regulatory asset for pensions and other postretirement benefits	43,914	84,040
Utility energy commodity and interest rate swap derivatives	23,364	31,871
Long-term debt and borrowing costs	19,992	31,955
Settlement with Coeur d'Alene Tribe	6,802	11,711
Other regulatory assets	16,695	30,183
Other	5,806	8,298
Total deferred income tax liabilities	693,216	1,048,275
Net long-term deferred income tax liability	$ 466,630	$ 840,928

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

As of December 31, 2017, the Company had $19.6 million of state tax credit carryforwards. Of the total amount, the Company believes that it is more likely than not that it will only be able to utilize $8.6 million of the state tax credits. As such, the Company has recorded a valuation allowance of $11.0 million against the state tax credit carryforwards and reflected the net amount of $8.6 million as an asset as of December 31, 2017. State tax credits expire from 2019 to 2028. The Company also has approximately $3.5 million of federal tax credit carryforwards and the Company believes that it is more likely than not all the federal credits will be utilized. The federal tax credits expire in 2036.

Status of Internal Revenue Service (IRS) Examinations

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon, Montana and Alaska. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The IRS has completed its examination of all tax years through 2011 and all issues were resolved related to these years. The statute of limitations for the IRS to review the 2012 and 2013 tax years has expired, and the Company has received a notice of an IRS review in 2018 for tax years 2014 through 2016. The Company believes that any open tax years for federal or state income taxes will not result in adjustments that would be significant to the consolidated financial statements.

Regulatory Assets and Liabilities Associated with Income Taxes

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

	2017	2016
Regulatory assets for deferred income taxes	$ 90,315	$ 109,853
Regulatory liabilities for deferred income taxes	460,542	28,966

NOTE 12. ENERGY PURCHASE CONTRACTS

The below discussion only relates to Avista Utilities. The sole energy purchase contract at AEL&P is a PPA for the Snettisham hydroelectric project and it is accounted for as a capital lease. AEL&P does not have any other significant operating agreements or contractual obligations. See Note 14 for further discussion of the Snettisham PPA.

Avista Utilities has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The remaining term of the contracts range from one month to twenty-five years.

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

	2017	2016	2015
Utility power resources	$ 380,523	$ 402,575	$ 511,937

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

	2018	2019	2020	2021	2022	Thereafter	Total
Power resources	$ 189,262	$ 185,610	$ 161,596	$ 149,125	$ 147,573	$ 916,255	$ 1,749,421
Natural gas resources	77,936	60,942	48,098	31,428	31,428	326,482	576,314
Total	$ 267,198	$ 246,552	$ 209,694	$ 180,553	$ 179,001	$ 1,242,737	$ 2,325,735

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

The above future contractual commitments for power resources include fixed contractual amounts related to the Company's contracts with certain PUDs to purchase portions of the output of certain generating facilities. Although Avista Utilities has no investment in the PUD generating facilities, the fixed contracts obligate Avista Utilities to pay certain minimum amounts whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in utility resource costs in the Consolidated Statements of Income. The contractual amounts included above consist of Avista Utilities' share of existing debt service cost and its proportionate share of the variable operating expenses of these projects. The minimum amounts payable under these contracts are based in part on the proportionate share of the debt service requirements of the PUD's revenue bonds for which the Company is indirectly responsible. The Company's total future debt service obligation associated with the revenue bonds outstanding at December 31, 2017 (principal and interest) was $63.5 million.

In addition, Avista Utilities has operating agreements, settlements and other contractual obligations related to its generating facilities and transmission and distribution services.

The expenses associated with these agreements are reflected as other operating expenses in the Consolidated Statements of Income. The following table details future contractual commitments under these agreements (dollars in thousands):

	2018	2019	2020	2021	2022	Thereafter	Total
Contractual obligations	$ 32,205	$ 34,996	$ 33,961	$ 28,939	$ 33,925	$ 193,595	$ 357,621

NOTE 13. COMMITTED LINES OF CREDIT

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million that expires in April 2021. The committed line of credit is secured by non-transferable first mortgage bonds of Avista Corp. issued to the agent bank that would only become due and payable in the event, and then only to the extent, that Avista Corp. defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2017, the Company was in compliance with this covenant.

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

	2017	2016
Balance outstanding at end of period	$ 105,000	$ 120,000
Letters of credit outstanding at end of period	$ 34,420	$ 34,353
Average interest rate at end of period	2.26%	1.50%

As of December 31, 2017 and 2016, the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Consolidated Balance Sheet. In addition, there were short-term borrowings outstanding as of December 31, 2017 on the Consolidated Balance Sheet related to a short-term note payable by a subsidiary for the acquisition of land that is expected to be repaid in early 2018.

AEL&P

AEL&P has a committed line of credit in the amount of $25.0 million that expires in November 2019. As of December 31, 2017 and 2016, there were no borrowings or letters of credit outstanding under this committed line of credit. The committed line of credit is secured by non-transferable first mortgage bonds of AEL&P issued to the agent bank that would only become due and payable in the event, and then only to the extent, that AEL&P defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "consolidated total debt at AEL&P" to "consolidated total capitalization at AEL&P," including the impact of the Snettisham bonds to be greater than 67.5 percent at any time. As of December 31, 2017, AEL&P was in compliance with this covenant.

NOTE 14. LONG-TERM DEBT AND CAPITAL LEASES

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

Maturity Year	Description	Interest Rate	2017	2016
Avista Corp. Secured Long-Term Debt				
2018	First Mortgage Bonds	5.95%	$ 250,000	$ 250,000
2018	Secured Medium-Term Notes	7.39%–7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2020	First Mortgage Bonds	3.89%	52,000	52,000
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%–7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (1)	(1)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2044	First Mortgage Bonds	4.11%	60,000	60,000
2045	First Mortgage Bonds	4.37%	100,000	100,000
2047	First Mortgage Bonds	4.23%	80,000	80,000
2047	First Mortgage Bonds (2)	3.91%	90,000	—
2051	First Mortgage Bonds	3.54%	175,000	175,000
	Total Avista Corp. secured long-term debt		1,711,700	1,621,700
Alaska Electric Light and Power Company Secured Long-Term Debt				
2044	First Mortgage Bonds	4.54%	75,000	75,000
	Total secured long-term debt		1,786,700	1,696,700
Alaska Energy and Resources Company Unsecured Long-Term Debt				
2019	Unsecured Term Loan	3.85%	15,000	15,000
	Total secured and unsecured long-term debt		1,801,700	1,711,700
Other Long-Term Debt Components				
	Capital lease obligations		62,148	65,435
	Unamortized debt discount		(626)	(792)
	Unamortized long-term debt issuance costs		(10,285)	(10,639)
	Total		1,852,937	1,765,704
	Secured Pollution Control Bonds held by Avista Corporation (2)		(83,700)	(83,700)
	Current portion of long-term debt and capital leases		(277,438)	(3,287)
	Total long-term debt and capital leases		$ 1,491,799	$ 1,678,717

(1) *In December 2010, $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due in 2032 and 2034, respectively, which had been held by Avista Corp. since 2008 and 2009, respectively, were refunded by new variable rate bond issues (Series 2010A and Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Consolidated Balance Sheets.*

(2) *In December 2017, Avista Corp. issued and sold $90.0 million of 3.91 percent first mortgage bonds due in 2047 pursuant to a bond purchase agreement with institutional investors in the private placement market. The total net proceeds from the sale of the bonds were used to repay a portion of the borrowings outstanding under Avista Corp.'s $400.0 million committed line of credit. In connection with the execution of the bond purchase agreement, Avista Corp. cash-settled five interest rate swap derivatives (notional aggregate amount of $60.0 million) and paid a total of $8.8 million.*

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

	2018	2019	2020	2021	2022	Thereafter	Total
Debt maturities	$ 272,500	$ 105,000	$ 52,000	$ —	$ 250,000	$ 1,090,047	$ 1,769,547

Substantially all of Avista Utilities' and AEL&P's owned properties are subject to the lien of their respective mortgage indentures. Under the Mortgages and Deeds of Trust (Mortgages) securing their first mortgage bonds (including secured medium-term notes), Avista Utilities and AEL&P may each issue additional first mortgage bonds under their specific mortgage in an aggregate principal amount equal to the sum of:

- $66\frac{2}{3}$ percent of the cost or fair value (whichever is lower) of property additions of that entity which have not previously been made the basis of any application under that entity's Mortgage, or
- an equal principal amount of retired first mortgage bonds of that entity which have not previously been made the basis of any application under that entity's Mortgage, or
- deposit of cash.

However, Avista Utilities and AEL&P may not individually issue any additional first mortgage bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the particular entity issuing the bonds has "net earnings" (as defined in that entity's Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months that were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the first mortgage bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2017, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.3 billion in aggregate principal amount of additional first mortgage bonds at Avista Utilities and $24.1 million at AEL&P.

Snettisham Capital Lease Obligation

Included in long-term capital leases above is a power purchase agreement between AEL&P and AIDEA, an agency of the State of Alaska, under which AEL&P has a take-or-pay obligation, expiring in December 2038, to purchase all the output of the 78 MW Snettisham Hydroelectric Project. For accounting purposes, this power purchase agreement is treated as a capital lease.

The balances related to the Snettisham capital lease obligation as of December 31 were as follows (dollars in thousands):

	2017	2016
Capital lease obligation [(1)]	$ 59,745	$ 62,160
Capital lease asset [(2)]	71,007	71,007
Accumulated amortization of capital lease asset [(2)]	12,745	9,104

(1) The capital lease obligation amount is equal to the amount of AIDEA's revenue bonds outstanding.

(2) These amounts are included in utility plant in service on the Consolidated Balance Sheets.

Interest on the capital lease obligation and amortization of the capital lease asset are included in utility resource costs in the Consolidated Statements of Income and totaled the following amounts for the years ended December 31 (dollars in thousands):

	2017	2016
Interest on capital lease obligation	$ 3,042	$ 3,157
Amortization of capital lease asset	3,641	3,642

AIDEA issued $100.0 million of revenue bonds in 1998 to finance its acquisition of the project, and the payments by AEL&P under the PPA were designed to be sufficient to enable the AIDEA to pay the principal of and interest on its revenue bonds (discussed below), which bore interest at rates ranging from 4.9 percent to 6.0 percent and were set to mature in January 2034.

In August 2015, AIDEA issued $65.7 million of new revenue bonds for the purpose of refunding all of the remaining outstanding revenue bonds for the Snettisham Hydroelectric Project. The new revenue bonds have interest rates ranging from 4.0 percent to 5.0 percent and mature in January 2034. The capital lease obligation on Avista Corp.'s Consolidated Balance Sheet at any given time is equal to the amount of revenue bonds outstanding at that time. The payments by AEL&P under the PPA between AEL&P and AIDEA are unconditional, notwithstanding any suspension, reduction or curtailment of the operation of the project. The bonds are payable solely out of AIDEA's receipts under the power purchase agreement. AEL&P is also obligated to operate, maintain and insure the project. AEL&P's payments for power under the agreement are between $10.7 million and $13.2 million per year, including the capital lease principal and interest of approximately $5.5 million per year.

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

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

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

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

	2018	2019	2020	2021	2022	Thereafter	Total
Principal	$ 2,535	$ 2,660	$ 2,800	$ 2,935	$ 3,085	$ 45,730	$ 59,745
Interest	2,921	2,795	2,662	2,522	2,375	14,300	27,575
Total	$ 5,456	$ 5,455	$ 5,462	$ 5,457	$ 5,460	$ 60,030	$ 87,320

NOTE 15. LONG-TERM DEBT TO AFFILIATED TRUSTS

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

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

	2017	2016	2015
Low distribution rate	1.81%	1.29%	1.11%
High distribution rate	2.36%	1.81%	1.29%
Distribution rate at the end of the year	2.36%	1.81%	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 at any time and mature on June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

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

NOTE 16. FAIR VALUE

The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable and short-term borrowings are reasonable estimates of their fair values. Long-term debt (including current portion and material capital leases) and long-term debt to affiliated trusts are reported at carrying value on the Consolidated Balance Sheets.

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

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

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

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

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

	2017		2016	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 951,000	$ 1,067,783	$ 951,000	$ 1,048,661
Long-term debt (Level 3)	767,000	810,598	677,000	675,251
Snettisham capital lease obligation (Level 3)	59,745	61,700	62,160	62,800
Long-term debt to affiliated trusts (Level 3)	51,547	41,882	51,547	38,660

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 81.25 to 130.03, where a par value of 100.00 represents the carrying value recorded on the 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 using comparable debt with similar risk and terms 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 Morgan Markets A Ex-Fin discount rate as published on December 31, 2017.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Consolidated Balance Sheets as of December 31, 2017 and 2016 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting [(1)]	Total
December 31, 2017					
Assets:					
Energy commodity derivatives	$ —	$ 43,814	$ —	$ (42,550)	$ 1,264
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	183	(183)	—
Foreign currency exchange derivatives	—	32	—	(1)	31
Interest rate swap derivatives	—	7,477	—	(2,574)	4,903
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities [(2)]	1,638	—	—	—	1,638
Equity securities [(2)]	6,631	—	—	—	6,631
Total	$ 8,269	$ 51,323	$ 183	$ (45,308)	$ 14,467
Liabilities:					
Energy commodity derivatives	$ —	$ 71,342	$ —	$ (69,988)	$ 1,354
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	3,347	(183)	3,164
Power exchange agreement	—	—	13,245	—	13,245
Power option agreement	—	—	19	—	19
Foreign currency exchange derivatives	—	1	—	(1)	—
Interest rate swap derivatives	—	73,513	—	(37,544)	35,969
Total	$ —	$ 144,856	$ 16,611	$ (107,716)	$ 53,751
December 31, 2016					
Assets:					
Energy commodity derivatives	$ —	$ 47,994	$ —	$ (46,099)	$ 1,895
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	69	(69)	—
Power exchange agreement	—	—	25	(25)	—
Foreign currency exchange derivatives	—	5	—	(5)	—
Interest rate swap derivatives	—	13,098	—	(4,348)	8,750
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities [(2)]	1,789	—	—	—	1,789
Equity securities [(2)]	5,481	—	—	—	5,481
Total	$ 7,270	$ 61,097	$ 94	$ (50,546)	$ 17,915
Liabilities:					
Energy commodity derivatives	$ —	$ 56,871	$ —	$ (55,957)	$ 914
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	5,954	(69)	5,885
Power exchange agreement	—	—	13,474	(25)	13,449
Power option agreement	—	—	76	—	76
Foreign currency exchange derivatives	—	28	—	(5)	23
Interest rate swap derivatives	—	73,978	—	(39,248)	34,730
Total	$ —	$ 130,877	$ 19,504	$ (95,304)	$ 55,077

(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 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 Consolidated Balance Sheets is due to netting arrangements with certain counterparties. See Note 6 for additional discussion of derivative netting.

To establish fair value for energy commodity derivatives, the Company uses quoted market prices and forward price curves to estimate the fair value of energy commodity derivative 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 swap derivatives, 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 swap derivatives 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 $0.2 million as of December 31, 2017 and $0.4 million as of December 31, 2016.

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, which expires in June 2019, 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) and 2) estimated delivery volumes. Significant increases or decreases in these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, changes in overall commodity market prices are accompanied by directionally similar changes in the strike price used in the calculation.

For the natural gas commodity exchange agreement, the Company uses the same Level 2 brokered quotes described above; however, the Company also estimates the purchase and sales volumes (within contractual limits) as well as the timing of those transactions. Changing the timing of volume estimates changes the timing of purchases and sales, impacting which brokered quote is used. Because the brokered quotes can vary significantly from period to period, the unobservable estimates of the timing and volume of transactions can have a significant impact on the calculated fair value. The Company currently estimates volumes and timing of transactions based on a most likely scenario using historical data. Historically, the timing and volume of transactions have not been highly correlated with market prices and market volatility.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of December 31, 2017 (dollars in thousands):

	Fair Value (Net) at December 31, 2017	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (13,245)	Surrogate facility pricing	O&M charges	$38.87–$45.20/MWh [1]
			Escalation factor	5%—2018 to 2019
			Transaction volumes	256,663–396,984 MWhs
Power option agreement	(19)	Black-Scholes-Merton	Strike price	$36.64/MWh—2018
				$42.51/MWh—2018
			Delivery volumes	94,221–190,339 MWhs
Natural gas exchange agreement	(3,164)	Internally derived weighted-average cost of gas	Forward purchase prices	$1.60–$2.07/mmBTU
			Forward sales prices	$1.56–$2.98/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 2017 are $41.95 per MWh.

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 years ended December 31 (dollars in thousands):

	Natural Gas Exchange Agreement	Power Exchange Agreement	Power Option Agreement	Total
Year ended December 31, 2017:				
Balance as of January 1, 2017	$ (5,885)	$ (13,449)	$ (76)	$ (19,410)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities [1]	3,292	(7,674)	57	(4,325)
Settlements	(571)	7,878	—	7,307
Ending balance as of December 31, 2017 [2]	$ (3,164)	$ (13,245)	$ (19)	$ (16,428)
Year ended December 31, 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]	259	400	48	707
Settlements	(1,105)	8,112	—	7,007
Ending balance as of December 31, 2016 [2]	$ (5,885)	$ (13,449)	$ (76)	$ (19,410)
Year ended December 31, 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]	(6,008)	(6,198)	300	(11,906)
Settlements	1,004	7,536	—	8,540
Ending balance as of December 31, 2015 [2]	$ (5,039)	$ (21,961)	$ (124)	$ (27,124)

(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 17. COMMON STOCK

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

- certain covenants applicable to preferred stock (when outstanding) contained in the Company's Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements,
- the hydroelectric licensing requirements of section 10(d) of the FPA (see Note 1),

- certain requirements under the OPUC approval of the AERC acquisition in 2014. The OPUC's AERC acquisition order requires Avista Utilities to maintain a capital structure of no less than 40 percent common equity (inclusive of short-term debt). This limitation may be revised upon request by the Company with approval from the OPUC, and
- the Merger Agreement with Hydro One, which states Avista Corp. cannot (A) declare, authorize, set aside for payment or pay any dividend on, or make any other distribution in respect of, any shares of its capital stock, other than (1) dividends paid by any subsidiary of the Company to the Company or to any wholly owned subsidiary of the Company, (2) quarterly cash dividends with respect to the Company common stock not to exceed the 2017 annual per share dividend rate by more than $0.06 per year, with record dates and payment dates consistent with the Company's current dividend practice, or (3) a "stub period" dividend to holders of record of Company common stock as of immediately prior to the effective time of the merger equal to the product of (x) the number of days from the record date for payment of the last quarterly dividend paid by the Company prior to the effective time of the merger, multiplied by (y) a daily dividend rate determined by dividing the amount of the last quarterly dividend prior to the effective time of the merger by ninety-one or (B) adjust, split, combine, subdivide or reclassify any shares of its capital stock (see "Note 4" for additional information regarding the merger).

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

	2017	2016	2015
Dividends paid per			
common share	$ 1.43	$ 1.37	$ 1.32

Under the most restrictive of the dividend limitations discussed above, which are the requirements of the Merger Agreement with Hydro One, the amount available for dividends at December 31, 2017 was limited to $97.6 million (which is based on the number of shares outstanding as of December 31, 2017 and an annual dividend of $1.49 per share that was declared on February 2, 2018).

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2017 and 2016.

Stock Repurchase Programs

During 2015, Avista Corp.'s Board of Directors approved a program to repurchase shares of the Company's outstanding common stock. The number of shares repurchased and the total cost of repurchases are disclosed in the Consolidated Statements of Equity. The average repurchase price was $32.66 in 2015. All repurchased shares reverted to the status of authorized but unissued shares.

Equity Issuances

In March 2016, the Company 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. Through December 31, 2017, 2.7 million shares were issued under these agreements resulting in total net proceeds of $120.0 million ($54.7 million in 2017 and $65.3 million in 2016), leaving 1.1 million shares remaining to be issued.

NOTE 18. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORPORATION SHAREHOLDERS

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corp. shareholders for the years ended December 31 (in thousands, except per share amounts):

	2017	2016	2015
Numerator:			
Net income from continuing operations attributable to Avista Corp. shareholders	$ 115,916	$ 137,228	$ 118,080
Net income from discontinued operations attributable to Avista Corp. shareholders	$ —	$ —	$ 5,147
Denominator:			
Weighted-average number of common shares outstanding—basic	64,496	63,508	62,301
Effect of dilutive securities:			
Performance and restricted stock awards	310	412	407
Weighted-average number of common shares outstanding—diluted	64,806	63,920	62,708
Earnings per common share attributable to Avista Corp. shareholders, basic:			
Earnings per common share from continuing operations	$ 1.80	$ 2.16	$ 1.90
Earnings per common share from discontinued operations	$ —	$ —	$ 0.08
Total earnings per common share attributable to Avista Corp. shareholders—basic	$ 1.80	$ 2.16	$ 1.98
Earnings per common share attributable to Avista Corp. shareholders—diluted:			
Earnings per common share from continuing operations	$ 1.79	$ 2.15	$ 1.89
Earnings per common share from discontinued operations	$ —	$ —	$ 0.08
Total earnings per common share attributable to Avista Corp. shareholders—diluted	$ 1.79	$ 2.15	$ 1.97

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

NOTE 19. 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 Pacific Gas & Electric (PG&E), Southern California Edison, San Diego Gas & Electric, the California Attorney General (AG), the California Department of Water Resources (CERS), and the California Public Utilities Commission (together, the "California Parties"). The penalty arises as a result of the FERC's 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 with the California Parties in 2014 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.

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 particularly during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement (CFSA) 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 Corp. is reducing TDG by constructing spill crest modifications on spill gates at the dam. These modifications have been shown to be effective in reducing TDG downstream. TDG monitoring and analysis is ongoing. Under the terms of the mitigation plan, Avista Corp. will continue to work with stakeholders to determine the degree to which TDG abatement reduces future mitigation obligations. The Company has sought, and 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 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. In 2017, parties to the CFSA reached an agreement regarding Avista Corp.'s obligations regarding fish passage and related issues. Avista Corp. filed this agreement, which amends the original Clark Fork Settlement Agreement, with the FERC. Avista Corp. has also initiated a license amendment and permitting efforts in support of construction of the permanent fishway at Cabinet Gorge. Construction is expected to begin in late 2018. The Company has sought, and 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.

Collective Bargaining Agreements

The Company's collective bargaining agreements with the IBEW represent approximately 45 percent of all of Avista Utilities' employees. A three-year agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the Avista Utilities' bargaining unit employees was approved in March 2016 and expires in March 2019.

A three-year agreement in Oregon, which covers approximately 50 employees will expire in March 2020.

A collective bargaining agreement with the local union of the IBEW in Alaska expires in March 2019. The collective bargaining agreement with the IBEW in Alaska represents approximately 50 percent of all AERC employees. The remainder of AERC's employees are non-union.

There is a risk that if collective bargaining agreements expire and new agreements are not reached in each of our jurisdictions, employees could strike. Given the magnitude of employees that are covered by collective bargaining agreements, this could result in disruptions to our operations. However, the Company believes that the possibility of this occurring is remote.

Legal Proceedings Related to the Pending Acquisition by Hydro One

See Note 4 for information regarding the proposed acquisition of the Company by Hydro One.

In connection with the proposed acquisition, as of the date of this annual report, the three lawsuits that had been filed in the United States District Court for the Eastern District of Washington have been voluntarily dismissed by the plaintiffs. Those cases were captioned as follows:

- *Jenß v. Avista Corporation., et al.,* No. 2:17-cv-00333 (E.D. Wash.) (filed September 25, 2017);
- *Samuel v. Avista Corporation, et al.,* No. 2:17-cv-00334 (E.D. Wash.) (filed September 26, 2017); and
- *Sharpenter v. Avista Corporation., et al.,* No. 2:17-cv-00336 (E.D. Wash.) (filed September 26, 2017)

There remains one lawsuit that has been filed in the Superior Court for the State of Washington in and for Spokane County, captioned as follows:

Fink v. Morris, et al., No. 17203616-6 (filed September 15, 2017, amended complaint filed October 25, 2017).

This lawsuit was filed against Hydro One Limited, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch, as well as all members of the Company's Board of Directors, namely Erik Anderson, Kristianne Blake, Donald Burke, Rebecca Klein, Scott Maw, Scott Morris, Marc Racicot, Heidi Stanley, John Taylor and Janet Widmann.

The complaint generally alleges that the members of the Board breached their fiduciary duties by, among other things, conducting an allegedly inadequate sale process and agreeing to the acquisition at a price that allegedly undervalues Avista Corporation, and that Hydro One Limited, Olympus Holding Corp., and Olympus Corp. aided and abetted those purported breaches of duty. The aiding and abetting claims were brought only against Hydro One Limited, Olympus Holding Corp. and Olympus Corp. The complaints seek various remedies, including monetary damages, including attorneys' fees and expenses. The complaint has been stayed by the court until the closing of the transaction at which time the plaintiff will have the option to file an amended complaint within 30 days of such closing. If the amended complaint is not filed within the 30 days the suit will be dismissed.

All defendants deny any wrongdoing in connection with the proposed acquisition and plan to vigorously defend against all pending claims; however, the Company cannot at this time predict the eventual outcome.

Other Contingencies

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

The Company routinely assesses, based on studies, expert analyses and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who either have or have not agreed to a settlement as well as recoveries from insurance carriers. The Company's policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred. For matters that affect Avista Utilities' or AEL&P's operations, the Company seeks, to the extent appropriate, recovery of incurred costs through the ratemaking process.

The Company has potential liabilities under the Endangered Species Act for species of fish, plants and wildlife that have either already been added to the endangered species list, listed as "threatened" or petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company. However, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to these issues.

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. In addition, the company holds additional non-hydro water rights. The state of Montana is examining the status of all water right claims within state boundaries through a general adjudication. Claims within the Clark Fork River basin could adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho has initiated adjudication in northern Idaho, which will ultimately include the lower Clark Fork River, the Spokane River and the Coeur d'Alene basin. The Company is and will continue to be a participant in these and any other relevant adjudication processes. The complexity of such adjudications makes each unlikely to be concluded in the foreseeable future. As such, it is not possible for the Company to estimate the impact of any outcome at this time. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

NOTE 20. REGULATORY MATTERS

Regulatory Assets and Liabilities

The following table presents the Company's regulatory assets and liabilities as of December 31, 2017 (dollars in thousands):

	Remaining Amortization Period	Receiving Regulatory Treatment: Earning a Return [1]	Receiving Regulatory Treatment: Not Earning a Return	Expected Recovery or Refund [2]	Total 2017	Total 2016
Regulatory Assets:						
Investment in exchange power—net	2019	$ 4,083	$ —	$ —	$ 4,083	$ 6,533
Regulatory assets for deferred income tax	(3)	90,315	—	—	90,315	109,853
Regulatory assets for pensions and other postretirement benefit plans	(4)	—	209,115	—	209,115	240,114
Current regulatory asset for energy commodity derivatives	(5)	—	24,991	—	24,991	11,365
Unamortized debt repurchase costs	(6)	11,880	—	—	11,880	13,700
Regulatory asset for settlement with Coeur d'Alene Tribe	2059	43,954	—	—	43,954	45,265
Demand side management programs	(3)	—	24,620	—	24,620	15,700
Decoupling surcharge	2019	22,359	—	—	22,359	43,126
Regulatory asset for utility plant to be abandoned	(7)	24,330	—	—	24,330	19,100
Regulatory asset for interest rate swaps	(8)	53,797	—	115,907	169,704	161,508
Non-current regulatory asset for energy commodity derivatives	(5)	—	18,967	—	18,967	16,919
Other regulatory assets	(3)	8,212	7,064	4,555	19,831	16,645
Total regulatory assets		$ 258,930	$ 284,757	$ 120,462	$ 664,149	$ 699,828
Regulatory Liabilities:						
Natural gas deferrals	(3)	$ 37,474	$ —	$ —	$ 37,474	$ 30,820
Power deferrals	(3)	29,873	—	—	29,873	23,528
Regulatory liability for utility plant retirement costs	(9)	285,786	—	—	285,786	273,983
Income tax related liabilities	(3) (10)	—	18,223	442,319	460,542	28,966
Regulatory liability for interest rate swaps	(8)	11,257	—	7,381	18,638	21,191
Provision for earnings sharing rebate	(3)	—	2,350	3,420	5,770	10,297
Decoupling rebate	2019	5,816	—	—	5,816	2,405
Other regulatory liabilities	(3)	1,926	2,528	—	4,454	5,762
Total regulatory liabilities		$ 372,132	$ 23,101	$ 453,120	$ 848,353	$ 396,952

(1) Earning a return includes either interest on the regulatory asset/liability or a return on the investment as a component of rate base at the allowed rate of return.

(2) Expected recovery is pending regulatory treatment including regulatory assets and liabilities with prior regulatory precedence.

(3) Remaining amortization period varies depending on timing of underlying transactions.

(4) As the Company has historically recovered and currently recovers its pension and other postretirement benefit costs related to its regulated operations in retail rates, the Company records a regulatory asset for that portion of its pension and other postretirement benefit funding deficiency.

(5) The WUTC and the 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. Realized benefits and losses result in adjustments to retail rates through purchased gas cost adjustments, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases. The resulting regulatory assets have been concluded to be probable of recovery through future rates.

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

(7) In March 2016, the WUTC granted the Company's Petition for an Accounting Order to defer and include in a regulatory asset the undepreciated value of its existing Washington electric meters and natural gas ERTs for the opportunity for later recovery. This accounting treatment is related to the Company's plan to replace approximately 253,000 of its existing electric meters with new two-way digital meters and the related software and support services through its AMI project in Washington State. Replacement of the meters is expected to begin in the second half of 2018.

Footnotes continue on next page.

(8) *For interest rate swap derivatives, Avista Corp. records all mark-to-market gains and losses in each accounting period as assets and liabilities and records offsetting regulatory assets and liabilities, such that there is no income statement impact. The interest rate swap derivatives are risk management tools similar to energy commodity derivatives. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt. The Company records an offset of interest rate swap derivative assets and liabilities with regulatory assets and liabilities, based on the prior practice of the commissions to provide recovery through the ratemaking process. Settled interest rate swap derivatives which have been through a general rate case proceeding are classified as earning a return in the table above, whereas all unsettled interest rate swap derivatives and settled interest rate swap derivatives which have not been included in a general rate case are classified as expected recovery. See below for additional information regarding the Company's 2016 settled interest rate swaps in the Washington general rate cases. The Idaho and Oregon portion of the 2016 settled interest rate swaps are included in earning a return because they were approved for recovery in those respective states.*

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

(10) *The amount pending recovery represents amounts due back to customers and resulted from the new federal income tax law and changing the federal income tax rate from 35 percent to 21 percent and revaluing all deferred income taxes as of December 31, 2017. The Company currently expects the amounts for utility plant items for Avista Utilities to be returned to customers over a period of approximately 36 years using the ARAM. The Company expects the AEL&P amounts to be returned to customers over a period of approximately 40 years. The Company does not currently have an estimate for non-plant items included in this balance as the Company is waiting for additional implementation guidance from various regulatory agencies. In addition, none of the excess deferred tax amounts have been through a regulatory proceeding as of this filing; therefore, a definitive amortization period has not been established. See Note 11 for additional discussion regarding the new federal income tax law.*

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge or liability on the Consolidated Balance Sheets for future prudence review and recovery or rebate through retail rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Avista Utilities and the costs included in base retail rates. This difference in net power supply costs primarily results from changes in:

- short-term wholesale market prices and sales and purchase volumes,
- the level, availability and optimization of hydroelectric generation,
- the level and availability of thermal generation (including changes in fuel prices),
- retail loads, and
- sales of surplus transmission capacity.

In Washington, the ERM allows Avista Utilities to periodically increase or decrease electric rates with WUTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers and defer these differences (over the $4.0 million deadband and sharing bands) for future surcharge or rebate to customers. For 2017, the Company recognized a pre-tax benefit of $4.6 million under the ERM in Washington compared to a benefit of $5.1 million for 2016. Total net deferred power costs under the ERM were a liability of $23.7 million as of December 31, 2017 and a liability of $21.3 million as of December 31, 2016. These deferred power cost balances represent amounts due to customers.

Avista Utilities has a PCA mechanism in Idaho that allows it to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, Avista Utilities defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers for future surcharge or rebate to customers. The October 1 rate adjustments recover or rebate power costs deferred during the preceding July–June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a liability of $6.1 million as of December 31, 2017 and a liability of $2.2 million as of December 31, 2016. These deferred power cost balances represent amounts due to customers.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Utilities files a PGA in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. Total net deferred natural gas costs to be refunded to customers were a liability of $37.5 million as of December 31, 2017 and a liability of $30.8 million as of December 31, 2016. These balances represent amounts due to customers.

Decoupling and Earnings Sharing Mechanisms

Decoupling (also known as an FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of Avista Utilities' jurisdictions, Avista Utilities' electric and natural gas revenues are adjusted so as to be based on the number of customers in certain customer rate classes and assumed "normal" kilowatt hour and therm sales, rather than being based on actual kilowatt hour and therm sales. The difference between revenues based on the number of customers and "normal" sales and revenues based on actual usage is deferred and either surcharged or rebated to customers beginning in the following year. Only residential and certain commercial customer classes are included in decoupling mechanisms.

Washington Decoupling and Earnings Sharing

In Washington, the WUTC approved the Company's decoupling mechanisms for electric and natural gas for a five-year period beginning January 1, 2015. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to a 3 percent increase 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 for the calendar year just ended. These earnings tests reflect actual decoupled revenues, normalized power supply costs and other normalizing adjustments. If the Company earns more than its authorized ROR in Washington, 50 percent of excess earnings are rebated to customers through adjustments to decoupling surcharge or rebate balances. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Idaho 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, beginning January 1, 2016.

For the period 2013 through 2015, the Company 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, the Company was required to share with customers 50 percent of any earnings above the 9.8 percent. This after-the-fact earnings test was discontinued, effective January 1, 2016, as part of the settlement of the Company's 2015 Idaho electric and natural gas general rates cases. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

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. There will be an opportunity for interested parties to review the mechanism and recommend changes, if any, by September 2019. In Oregon, an earnings review is conducted on an annual basis. In the annual earnings review, if the Company earns more than 100 basis points above its allowed ROE, one-third of the earnings above the 100 basis points would be deferred and later returned to customers. The earnings review is separate from the decoupling mechanism and was in place prior to decoupling.
See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Cumulative Decoupling and Earnings Sharing Mechanism Balances

As of December 31, 2017 and December 31, 2016, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in thousands):

	December 31, 2017	December 31, 2016
Washington		
Decoupling surcharge	$ 14,240	$ 30,408
Provision for earnings sharing rebate	(3,420)	(5,113)
Idaho		
Decoupling surcharge	$ 3,471	$ 8,292
Provision for earnings sharing rebate	(2,350)	(5,184)
Oregon		
Decoupling surcharge (rebate)	$ (1,168)	$ 2,021
Provision for earnings sharing rebate	—	—

Interest Rate Swaps included in the 2017 Washington General Rate Cases

On October 27, 2017, WUTC Staff and other parties to Avista Corp.'s electric and natural gas general rate cases filed their testimony. These parties recommended lower revenue requirements than what was proposed in Avista Corp.'s original filings. Additionally, the WUTC Staff recommended the exclusion of the Company's 2016 settlement costs from the cost of capital calculation. The total amount of the 2016 settlement costs was $54.0 million, with approximately 60 percent of this total being allocable to Washington.

In addition to the settlement costs from 2016, the Company has a net regulatory asset of $8.8 million for interest rate swaps settled during the third quarter of 2017, and a net regulatory asset of $66.0 million for unsettled interest rate swaps as of December 31, 2017 related to forecasted debt issuances. Of those amounts, approximately 60 percent relate to Washington. If recovery of the 2016 settled interest rate swap settlement payments referenced above is disallowed by the WUTC, this could change the Company's current conclusion that settlement payments related to the 2017 settled interest rate swaps and the unsettled interest rate swaps are probable of recovery through rates. If the Company concluded that recovery of these swap related payments were no longer probable, the Company will be required to derecognize the related regulatory assets and liabilities with an adjustment through the income statement, and any subsequent gains and losses would be recognized through the income statement rather than recorded as a regulatory asset or liability.

Interest rate swaps are a tool used throughout multiple industries to manage interest rate risk. They also provide certainty for future cash flows associated with future borrowings. Since interest costs are included in the Company's costs of service to be recovered from customers, the Company has used this tool to manage these costs for the benefit of the Company's customers. The settlement of interest rate swaps results in either a benefit or a cost to the Company which, in either case, has historically been reflected in rates authorized by the WUTC in general rate cases. Accordingly, the Company still believes the interest rate swap payments are probable of recovery and will continue to work through the rate case process. Depending on the outcome of this proceeding, the Company could determine to not manage interest rate risk through swap transactions in the future.

NOTE 21. 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 year ended December 31, 2017:						
Operating revenues	$ 1,370,359	$ 53,027	$ 1,423,386	$ 22,543	$ —	$ 1,445,929
Resource costs	511,163	13,403	524,566	—	—	524,566
Other operating expenses [2]	319,899	12,532	332,431	25,650	—	358,081
Depreciation and amortization	165,478	5,803	171,281	740	—	172,021
Income (loss) from operations	270,409	17,947	288,356	(3,847)	—	284,509
Interest expense [3]	92,019	3,581	95,600	781	(189)	96,192
Income taxes	77,583	5,515	83,098	(340)	—	82,758
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	114,716	9,054	123,770	(7,854)	—	115,916
Capital expenditures [4]	405,938	6,401	412,339	4,280	—	416,619
For the year ended December 31, 2016:						
Operating revenues	$ 1,372,638	$ 46,276	$ 1,418,914	$ 23,569	$ —	$ 1,442,483
Resource costs	539,352	12,014	551,366	—	—	551,366
Other operating expenses	304,644	11,151	315,795	25,501	—	341,296
Depreciation and amortization	155,162	5,352	160,514	769	—	161,283
Income (loss) from operations	277,070	15,434	292,504	(2,701)	—	289,803
Interest expense [3]	83,070	3,584	86,654	608	(132)	87,130
Income taxes	74,121	5,321	79,442	(1,356)	—	78,086
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	132,490	7,968	140,458	(3,230)	—	137,228
Capital expenditures [4]	390,690	15,954	406,644	353	—	406,997
For the year ended December 31, 2015:						
Operating revenues	$ 1,411,863	$ 44,778	$ 1,456,641	$ 28,685	$ (550)	$ 1,484,776
Resource costs	644,991	11,973	656,964	—	—	656,964
Other operating expenses	292,096	11,125	303,221	30,076	(550)	332,747
Depreciation and amortization	138,236	5,263	143,499	695	—	144,194
Income (loss) from operations	241,228	14,072	255,300	(2,086)	—	253,214
Interest expense [3]	76,405	3,558	79,963	610	(132)	80,441
Income taxes	64,489	4,202	68,691	(1,242)	—	67,449
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	113,360	6,641	120,001	(1,921)	—	118,080
Capital expenditures [4]	381,174	12,251	393,425	885	—	394,310
Total Assets:						
As of December 31, 2017	$ 5,177,878	$ 278,688	$ 5,456,566	$ 73,241	$ (15,075)	$ 5,514,732
As of December 31, 2016	$ 4,975,555	$ 273,770	$ 5,249,325	$ 60,430	$ —	$ 5,309,755
As of December 31, 2015	$ 4,601,708	$ 265,735	$ 4,867,443	$ 39,206	$ —	$ 4,906,649

(1) Intersegment eliminations reported as interest expense represent intercompany interest. Intersegment eliminations reported as operating revenues and other operating expenses for 2015 represent intercompany purchases and sales of electric capacity and energy between Avista Utilities and Spokane Energy (included in other). Intersegment eliminations reported as assets represent intersegment accounts receivable.

(2) Other operating expenses for Avista Utilities for 2017 includes acquisition costs of $14.6 million which are separately disclosed on the Consolidated Statements of Income.

(3) Including interest expense to affiliated trusts.

(4) The capital expenditures for the other businesses are included in other investing activities on the Consolidated Statements of Cash Flows.

NOTE 22. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The Company's energy operations are significantly affected by weather conditions. Consequently, there can be large variances in revenues, expenses and net income between quarters based on seasonal factors such as, but not limited to, temperatures and streamflow conditions, including the impact on electric and natural gas commodity prices.

A summary of quarterly operations (in thousands, except per share amounts) for 2017 and 2016 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2017				
Operating revenues	$ 436,470	$ 314,501	$ 297,096	$ 397,862
Operating expenses	321,084	258,404	266,054	315,878
Income from operations	$ 115,386	$ 56,097	$ 31,042	$ 81,984
Net income	62,137	21,722	4,458	27,615
Net loss (income) attributable to noncontrolling interests	(21)	49	(7)	(37)
Net income attributable to Avista Corporation shareholders	$ 62,116	$ 21,771	$ 4,451	$ 27,578
Outstanding common stock:				
weighted-average—basic	64,362	64,401	64,412	64,809
weighted-average—diluted	64,469	64,553	64,892	65,308
Earnings per common share attributable to Avista Corp. shareholders—diluted	$ 0.96	$ 0.34	$ 0.07	$ 0.42
2016				
Operating revenues from continuing operations	$ 418,173	$ 318,838	$ 303,349	$ 402,123
Operating expenses from continuing operations	312,088	257,247	263,755	319,590
Income from continuing operations	$ 106,085	$ 61,591	$ 39,594	$ 82,533
Net income	57,665	27,287	12,261	40,103
Net income attributable to noncontrolling interests	(16)	(33)	(27)	(12)
Net income attributable to Avista Corporation shareholders	$ 57,649	$ 27,254	$ 12,234	$ 40,091
Outstanding common stock:				
weighted-average—basic	62,605	63,386	63,857	64,185
weighted-average—diluted	62,907	63,783	64,325	64,620
Earnings per common share attributable to Avista Corp. shareholders—diluted	$ 0.92	$ 0.43	$ 0.19	$ 0.62

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a–15(e) and 15d–15(e) under the Securities Exchange Act of 1934, as amended (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 December 31, 2017.

Management's Report on Internal Control Over Financial Reporting

The Company's management, together with its consolidated subsidiaries, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a–15(f) under the Securities Exchange Act of 1934). The Company's internal control over financial reporting is a process designed under the supervision of the Company's principal executive officer and principal financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with accounting principles generally accepted in the United States of America.

The Company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's financial statements.

Under the supervision and with the participation of the Company's management, including the Company's principal executive officer and principal financial officer, the Company conducted an assessment of the effectiveness of the Company's internal control over financial reporting based on the framework established in *Internal Control–Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that the Company's internal control over financial reporting as of December 31, 2017 is effective at a reasonable assurance level.

The Company's independent registered public accounting firm, Deloitte & Touche LLP, has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2017.

Changes in Internal Control Over Financial Reporting

There have been no changes in the Company's internal control over financial reporting that occurred during the Company's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of
Directors of Avista Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Avista Corporation and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2017, of the Company and our report dated February 20, 2018, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 20, 2018

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this Item (other than the information regarding executive officers and the Company's Code of Business Conduct and Ethics set forth below) is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 10, 2018, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2017, relating to its Annual Meeting of Shareholders held on May 11, 2017.

Executive Officers of the Registrant

Name	**Age**	**Business Experience**
Scott L. Morris	60	Chairman and Chief Executive Officer effective January 1, 2018; Chairman, President and Chief Executive Officer effective January 2008–December 2017; Director since February 9, 2007; President and Chief Operating Officer May 2006–December 2007; Senior Vice President February 2002–May 2006; Vice President November 2000–February 2002; President—Avista Utilities August 2000–December 2008; General Manager—Avista Utilities for the Oregon and California operations October 1991–August 2000; various other management and staff positions with the Company since 1981.
Mark T. Thies	54	Treasurer since January 2013; Senior Vice President and Chief Financial Officer (Principal Financial Officer) since September 2008; prior to employment with the Company held the following positions with Black Hills Corporation: Executive Vice President and Chief Financial Officer March 2003–January 2008; Senior Vice President and Chief Financial Officer March 2000–March 2003; Controller May 1997–March 2000.
Marian M. Durkin	64	Senior Vice President, General Counsel and Chief Compliance Officer since November 2005; Corporate Secretary since May 2016; Senior Vice President and General Counsel August 2005–November 2005; prior to employment with the Company: held several legal positions with United Airlines, Inc. from 1995–August 2005, most recently served as Vice President Deputy General Counsel and Assistant Secretary.
Karen S. Feltes	62	Senior Vice President of Human Resources since November 2005; Corporate Secretary November 2005–April 2016; Vice President of Human Resources and Corporate Secretary March 2003–November 2005; Vice President of Human Resources and Corporate Services February 2002–March 2003; various human resources positions with the Company April 1998–February 2002.
Dennis P. Vermillion	56	President of Avista Corp since January 2018; Director since January 2018; Senior Vice President since January 2010; Vice President July 2007–December 2009; President—Avista Utilities since January 2009; Vice President of Energy Resources and Optimization—Avista Utilities July 2007–December 2008; President and Chief Operating Officer of Avista Energy February 2001–July 2007; various other management and staff positions with the Company since 1985.
Jason R. Thackston	47	Senior Vice President since January 2014; Vice President of Energy Resources since December 2012; Vice President of Customer Solutions—Avista Utilities June 2012–December 2012; Vice President of Energy Delivery April 2011–December 2012; Vice President of Finance June 2009–April 2011; various other management and staff positions with the Company since 1996.

Ryan L. Krasselt	48	Vice President, Controller and Principal Accounting Officer since October 2015; various other management and staff positions with the Company since 2001.
Kevin J. Christie	50	Vice President, External Affairs and Chief Customer Officer since January 2018; Vice President of Customer Solutions since February 2015; various other management and staff positions with the Company since 2005.
James M. Kensok	59	Vice President and Chief Information Officer since January 2007; Chief Information Officer February 2001–December 2006; various other management and staff positions with the Company since 1996.
David J. Meyer	64	Vice President and Chief Counsel for Regulatory and Governmental Affairs since February 2004; Senior Vice President and General Counsel September 1998–February 2004.
Heather L. Rosentrater	40	Vice President of Energy Delivery since December 2015; various other management and staff positions with the Company since 1996.
Edward D. Schlect Jr.	57	Vice President and Chief Strategy Officer since September 2015; prior to employment with the Company, Executive Vice President of Corporate Development at Ecova, Inc.
Bryan A. Cox	48	Vice President, Safety and Human Resources Shared Services since January 2018; various other management and staff positions with the Company since 1997.

All of the Company's executive officers, with the exception of James M. Kensok, David J. Meyer, Kevin J. Christie, Heather L. Rosentrater and Bryan A. Cox were officers or directors of one or more of the Company's subsidiaries in 2017. The Company's executive officers are elected annually by the Board of Directors.

The Company has adopted a Code of Conduct for directors, officers (including the principal executive officer, principal financial officer and principal accounting officer), and employees. The Code of Conduct is available on the Company's website at www.avistacorp.com and will also be provided to any shareholder without charge upon written request to:

Avista Corp.
General Counsel
P.O. Box 3727 MSC-12
Spokane, Washington 99220-3727

Any changes to or waivers for executive officers and directors of the Company's Code of Conduct will be posted on the Company's website.

Item 11. Executive Compensation

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 10, 2018, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2017, relating to its Annual Meeting of Shareholders held on May 11, 2017.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

(a) Security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities):

Information regarding security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities) has been omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 10, 2018, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2017, relating to its Annual Meeting of Shareholders held on May 11, 2017; reference also being made to Schedules 13G, as amended, on file with the SEC with respect to the Registrant's voting securities (the information contained in such schedules 13G, as amended, not being incorporated herein by reference).

(b) Security ownership of management:

The information required by this Item regarding the security ownership of management is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 10, 2018, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2017, relating to its Annual Meeting of Shareholders held on May 11, 2017.

(c) Changes in control:

None.

(d) Securities authorized for issuance under equity compensation plans as of December 31, 2017:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights [1]	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders [2]	—	$ —	1,481,664

(1) Excludes unvested restricted shares and performance share awards granted under Avista Corp.'s Long-Term Incentive Plan. At December 31, 2017, 106,053 Restricted Share awards were outstanding. Performance and market-based share awards may be paid out at zero shares at a minimum achievement level; 327,088 shares at target level; or 654,176 shares at a maximum level. Because there is no exercise price associated with restricted shares or performance and market-based share awards, such shares are not included in the weighted-average price calculation.

(2) Includes the Long-Term Incentive Plan approved by shareholders in 1998 and the Non-Employee Director Stock Plan approved by shareholders in 1996. In February 2005, the Board of Directors elected to terminate the Non-Employee Director Stock Plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 10, 2018, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2017, relating to its Annual Meeting of Shareholders held on May 11, 2017.

Item 14. Principal Accounting Fees and Services

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 10, 2018, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2017, relating to its Annual Meeting of Shareholders held on May 11, 2017.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) 1. Financial Statements (Included in Part II of this report):

Report of Independent Registered Public Accounting Firm

Consolidated Statements of Income for the Years Ended December 31, 2017, 2016 and 2015

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2017, 2016 and 2015

Consolidated Balance Sheets as of December 31, 2017 and 2016

Consolidated Statements of Cash Flows for the Years Ended December 31, 2017, 2016 and 2015

Consolidated Statements of Equity for the Years Ended December 31, 2017, 2016 and 2015

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules:

None

(a) 3. Exhibits:

Reference is made to the Exhibit Index commencing on the following page. The Exhibits include the management contracts and compensatory plans or arrangements required to be filed as exhibits to this Form 10-K pursuant to Item 15(b).

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

AVISTA CORPORATION

February 20, 2018	By /s/ Scott L. Morris
Date	Scott L. Morris Chairman of the Board and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Scott L. Morris Scott L. Morris Chairman of the Board and Chief Executive Officer	Principal Executive Officer	February 20, 2018
/s/ Mark T. Thies Mark T. Thies Senior Vice President, Chief Financial Officer, and Treasurer	Principal Financial Officer	February 20, 2018
/s/ Ryan L. Krasselt Ryan L. Krasselt Vice President, Controller, and Principal Accounting Officer	Principal Accounting Officer	February 20, 2018
/s/ Dennis P. Vermillion Dennis P. Vermillion President	Director	February 20, 2018
/s/ Erik J. Anderson Erik J. Anderson	Director	February 20, 2018
/s/ Kristianne Blake Kristianne Blake	Director	February 20, 2018
/s/ Donald C. Burke Donald C. Burke	Director	February 20, 2018
/s/ Rebecca A. Klein Rebecca A. Klein	Director	February 20, 2018
/s/ Scott H. Maw Scott H. Maw	Director	February 20, 2018
/s/ Marc F. Racicot Marc F. Racicot	Director	February 20, 2018
/s/ Heidi B. Stanley Heidi B. Stanley	Director	February 20, 2018
/s/ R. John Taylor R. John Taylor	Director	February 20, 2018
/s/ Janet D. Widmann Janet D. Widmann	Director	February 20, 2018

Exhibit	With Registration Number	Previously Filed [1] As Exhibit	
3.1	(with June 30, 2012 Form 10-Q)	3.1	Restated Articles of Incorporation of Avista Corporation, as amended and restated June 6, 2012.
3.2	(with Form 8-K filed as of August 17, 2016)	3.2	Bylaws of Avista Corporation, as amended August 17, 2016.
4.1	2-4077	B-3	Mortgage and Deed of Trust, dated as of June 1, 1939.
4.2	2-9812	4(c)	First Supplemental Indenture, dated as of October 1, 1952.
4.3	2-60728	2(b)-2	Second Supplemental Indenture, dated as of May 1, 1953.
4.4	2-13421	4(b)-3	Third Supplemental Indenture, dated as of December 1, 1955.
4.5	2-13421	4(b)-4	Fourth Supplemental Indenture, dated as of March 15, 1967.
4.6	2-60728	2(b)-5	Fifth Supplemental Indenture, dated as of July 1, 1957.
4.7	2-60728	2(b)-6	Sixth Supplemental Indenture, dated as of January 1, 1958.
4.8	2-60728	2(b)-7	Seventh Supplemental Indenture, dated as of August 1, 1958.
4.9	2-60728	2(b)-8	Eighth Supplemental Indenture, dated as of January 1, 1959.
4.10	2-60728	2(b)-9	Ninth Supplemental Indenture, dated as of January 1, 1960.
4.11	2-60728	2(b)-10	Tenth Supplemental Indenture, dated as of April 1, 1964.
4.12	2-60728	2(b)-11	Eleventh Supplemental Indenture, dated as of March 1, 1965.
4.13	2-60728	2(b)-12	Twelfth Supplemental Indenture, dated as of May 1, 1966.
4.14	2-60728	2(b)-13	Thirteenth Supplemental Indenture, dated as of August 1, 1966.
4.15	2-60728	2(b)-14	Fourteenth Supplemental Indenture, dated as of April 1, 1970.
4.16	2-60728	2(b)-15	Fifteenth Supplemental Indenture, dated as of May 1, 1973.
4.17	2-60728	2(b)-16	Sixteenth Supplemental Indenture, dated as of February 1, 1975.
4.18	2-60728	2(b)-17	Seventeenth Supplemental Indenture, dated as of November 1, 1976.
4.19	2-69080	2(b)-18	Eighteenth Supplemental Indenture, dated as of June 1, 1980.
4.20	(with 1980 Form 10-K)	4(a)-20	Nineteenth Supplemental Indenture, dated as of January 1, 1981.
4.21	2-79571	4(a)-21	Twentieth Supplemental Indenture, dated as of August 1, 1982.
4.22	(with Form 8-K dated September 20, 1983)	4(a)-22	Twenty-First Supplemental Indenture, dated as of September 1, 1983.
4.23	2-94816	4(a)-23	Twenty-Second Supplemental Indenture, dated as of March 1, 1984.

Exhibit	With Registration Number	Previously Filed [1] As Exhibit	
4.24	(with 1986 Form 10-K)	4(a)-24	Twenty-Third Supplemental Indenture, dated as of December 1, 1986.
4.25	(with 1987 Form 10-K)	4(a)-25	Twenty-Fourth Supplemental Indenture, dated as of January 1, 1988.
4.26	(with 1989 Form 10-K)	4(a)-26	Twenty-Fifth Supplemental Indenture, dated as of October 1, 1989.
4.27	33-51669	4(a)-27	Twenty-Sixth Supplemental Indenture, dated as of April 1, 1993.
4.28	(with 1993 Form 10-K)	4(a)-28	Twenty-Seventh Supplemental Indenture, dated as of January 1, 1994.
4.29	(with 2001 Form 10-K)	4(a)-29	Twenty-Eighth Supplemental Indenture, dated as of September 1, 2001.
4.30	333-82502	4(b)	Twenty-Ninth Supplemental Indenture, dated as of December 1, 2001.
4.31	(with June 30, 2002 Form 10-Q)	4(f)	Thirtieth Supplemental Indenture, dated as of May 1, 2002.
4.32	333-39551	4(b)	Thirty-First Supplemental Indenture, dated as of May 1, 2003.
4.33	(with September 30, 2003 Form 10-Q)	4(f)	Thirty-Second Supplemental Indenture, dated as of September 1, 2003.
4.34	333-64652	4(a)33	Thirty-Third Supplemental Indenture, dated as of May 1, 2004.
4.35	(with Form 8-K dated as of December 15, 2004)	4.1	Thirty-Fourth Supplemental Indenture, dated as of November 1, 2004.
4.36	(with Form 8-K dated as of December 15, 2004)	4.2	Thirty-Fifth Supplemental Indenture, dated as of December 1, 2004.
4.37	(with Form 8-K dated as of December 15, 2004)	4.3	Thirty-Sixth Supplemental Indenture, dated as of December 1, 2004.
4.38	(with Form 8-K dated as of December 15, 2004)	4.4	Thirty-Seventh Supplemental Indenture, dated as of December 1, 2004.
4.39	(with Form 8-K dated as of May 12, 2005)	4.1	Thirty-Eighth Supplemental Indenture, dated as of May 1, 2005.
4.40	(with Form 8-K dated as of November 17, 2005)	4.1	Thirty-Ninth Supplemental Indenture, dated as of November 1, 2005.
4.41	(with Form 8-K dated as of April 6, 2006)	4.1	Fortieth Supplemental Indenture, dated as of April 1, 2006.
4.42	(with Form 8-K dated as of December 15, 2006)	4.1	Forty-First Supplemental Indenture, dated as of December 1, 2006.
4.43	(with Form 8-K dated as of April 3, 2008)	4.1	Forty-Second Supplemental Indenture, dated as of April 1, 2008.
4.44	(with Form 8-K dated as of November 26, 2008)	4.1	Forty-Third Supplemental Indenture, dated as of November 1, 2008.

Exhibit	With Registration Number	Previously Filed [1] As Exhibit	
4.45	(with Form 8-K dated as of December 16, 2008)	4.1	Forty-Fourth Supplemental Indenture, dated as of December 1, 2008.
4.46	(with Form 8-K dated as of December 30, 2008)	4.3	Forty-Fifth Supplemental Indenture, dated as of December 1, 2008.
4.47	(with Form 8-K dated as of September 15, 2009)	4.1	Forty-Sixth Supplemental Indenture, dated as of September 1, 2009.
4.48	(with Form 8-K dated as of November 25, 2009)	4.1	Forty-Seventh Supplemental Indenture, dated as of November 1, 2009.
4.49	(with Form 8-K dated as of December 15, 2010)	4.5	Forty-Eighth Supplemental Indenture, dated as of December 1, 2010.
4.50	(with Form 8-K dated as of December 20, 2010)	4.1	Forty-Ninth Supplemental Indenture, dated as of December 1, 2010.
4.51	(with Form 8-K dated as of December 30, 2010)	4.1	Fiftieth Supplemental Indenture, dated as of December 1, 2010.
4.52	(with Form 8-K dated as of February 11, 2011)	4.1	Fifty-First Supplemental Indenture, dated as of February 1, 2011.
4.53	(with Form 8-K dated as of August 16, 2011)	4.1	Fifty-Second Supplemental Indenture, dated as of August 1, 2011.
4.54	(with Form 8-K dated as of December 14, 2011)	4.1	Fifty-Third Supplemental Indenture, dated as of December 1, 2011.
4.55	(with Form 8-K dated as of November 30, 2012)	4.1	Fifty-Fourth Supplemental Indenture, dated as of November 1, 2012.
4.56	(with Form 8-K dated as of August 14, 2013)	4.1	Fifty-Fifth Supplemental Indenture, dated as of August 1, 2013.
4.57	(with Form 8-K dated as of April 18, 2014)	4.1	Fifty-Sixth Supplemental Indenture, dated as of April 1, 2014.
4.58	(with Form 8-K dated as of December 18, 2014)	4.1	Fifty-Seventh Supplemental Indenture, dated as of December 1, 2014.
4.59	(with Form 8-K dated as of December 16, 2015)	4.1	Fifty-Eighth Supplemental Indenture, dated as of December 1, 2015.
4.60	(with Form 8-K dated as of December 16, 2016)	4.1	Fifty-Ninth Supplemental Indenture, dated as of December 1, 2016.
4.61	(with Form 8-K dated as of December 14, 2017)	4.1	Sixtieth Supplemental Indenture, dated as of December 1, 2017.

Exhibit	With Registration Number	Previously Filed [1] As Exhibit	
4.62	(with Form 8-K dated as of December 15, 2004)	4.5	Supplemental Indenture No. 1, dated as of December 1, 2004 to the Indenture dated as of April 1, 1998 between Avista Corporation and JPMorgan Chase Bank, N.A.
4.63	333-82165	4(a)	Indenture dated as of April 1, 1998 between Avista Corporation and The Bank of New York, as Successor Trustee.
4.64	(with Form 8-K dated as of December 15, 2010)	4.1	Loan Agreement between City of Forsyth, Montana and Avista Corporation $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A dated as of December 1, 2010.
4.65	(with Form 8-K dated as of December 15, 2010)	4.3	Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A, dated as of December 1, 2010.
4.66	(with Form 8-K dated as of December 15, 2010)	4.2	Loan Agreement between City of Forsyth, Montana and Avista Corporation $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B dated as of December 1, 2010.
4.67	(with Form 8-K dated as of December 15, 2010)	4.4	Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B, dated as of December 1, 2010.
4.68	(with June 30, 2012 Form 10-Q)	3.1	Restated Articles of Incorporation of Avista Corporation, as amended and restated June 6, 2012 (see Exhibit 3.1 herein).
4.69	(with Form 8-K filed as of August 17, 2016)	3.2	Bylaws of Avista Corporation, as amended August 17, 2016 (see Exhibit 3.2 herein).
4.70	(Form 10/A)	N/A	Post-Effective Amendment No. 1 on Form 10/A, filed February 26, 2015, to Registration Statement on Form 10, filed September 1952.
10.1	(with Form 8-K dated as of February 11, 2011)	10.1	Credit Agreement, dated as of February 11, 2011, among Avista Corporation, the Banks Party hereto, The Bank of New York Mellon, Keybank National Association, and U.S. Bank National Association, as Co-Documentation Agents, Wells Fargo Bank National Association as Syndication Agent and an an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.
10.2	(with Form 8-K dated as of April 18, 2014)	10.1	Second Amendment to Credit Agreement, dated as of April 18, 2014, among Avista Corporation, Wells Fargo Bank, National Association, as an Issuing Bank, Union Bank, N.A. as Administrative Agent and an Issuing Bank, and the financial institutions identified hereof as Continuing Lenders and Exiting Lender.
10.3	(with Form 8-K dated as of April 18, 2014)	10.2	Bond Delivery Agreement, dated as of April 18, 2014, between Avista Corporation and Union Bank, N.A.

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
10.4	(with Form 8-K dated as of December 14, 2011)	10.1	First Amendment and Waiver Thereunder, dated as of December 14, 2011, to the Credit Agreement dated as of February 11, 2011, among Avista Corporation, the Banks Party hereto, Wells Fargo Bank National Association as an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.
10.5	(with 2002 Form 10-K)	10(b)-3	Priest Rapids Project Product Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.6	(with 2002 Form 10-K)	10(b)-4	Priest Rapids Project Reasonable Portion Power Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.7	(with 2002 Form 10-K)	10(b)-5	Additional Product Sales Agreement (Priest Rapids Project) executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.8	2-60728	5(g)	Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.
10.9	2-60728	5(g)-1	Amendment to Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.
10.10	2-60728	5(h)	Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.
10.11	2-60728	5(h)-1	Amendment to Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.
10.12	(with September 30, 1985 Form 10-Q)	1	Settlement Agreement and Covenant Not to Sue executed by the United States Department of Energy acting by and through the Bonneville Power Administration and the Company, dated as of September 17, 1985, describing the settlement of Project 3 litigation.
10.13	(with 1981 Form 10-K)	10(s)-7	Ownership and Operation Agreement for Colstrip Units No. 3 & 4, dated as of May 6, 1981.
10.14	[2]		Avista Corporation Executive Deferral Plan. [3][5]
10.15	[2]		Avista Corporation Executive Deferral Plan. [3][6]
10.16	[2]		Avista Corporation Executive Deferral Plan [3][7]
10.17	(with 2011 Form 10-K)	10.17	Avista Corporation Supplemental Executive Retirement Plan. [3][8][9]

Exhibit	With Registration Number	Previously Filed [1] As Exhibit	
10.18	(with 2011 Form 10-K)	10.18	Avista Corporation Supplemental Executive Retirement Plan. [3][6]
10.19	(with 1992 Form 10-K)	10(t)-11	The Company's Unfunded Supplemental Executive Disability Plan. [3]
10.20	(with 2007 Form 10-K)	10.34	Income Continuation Plan of the Company. [3]
10.21	(with 2010 Definitive Proxy Statement filed March 31, 2010)	Appendix A	Avista Corporation Long-Term Incentive Plan. [3]
10.22	(with 2010 Form 10-K)	10.23	Avista Corporation Performance Award Plan Summary. [3]
10.23	(with 2015 Form 10-K)	10.31	Avista Corporation Performance Award Agreement 2015. [3]
10.24	(with 2016 Form 10-K)	10.24	Avista Corporation Performance Award Agreement 2016. [3]
10.25	[2]		Avista Corporation Performance Award Agreement 2017. [3]
10.26	(with Form 8-K dated June 21, 2005)	10.1	Employment Agreement between the Company and Marian Durkin in the form of a Letter of Employment. [3]
10.27	(with Form 8-K dated August 13, 2008)	10.1	Employment Agreement between the Company and Mark T. Thies in the form of a Letter of Employment. [3]
10.28	333-47290	99.1	Non-Officer Employee Long-Term Incentive Plan.
10.29	(with 2010 Form 10-K)	10.28	Form of Change of Control Agreement between the Company and its Executive Officers. [3][8]
10.30	(with 2010 Form 10-K)	10.29	Form of Change of Control Agreement between the Company and its Executive Officers. [3][9]
10.31	(with 2010 Form 10-K)	10.30	Form of Change of Control Agreement between the Company and its Executive Officers. [3][10]
10.32	(with 2010 Form 10-K)	10.31	Form of Change of Control Agreement between the Company and its Executive Officers. [3][11]
10.33	[2]		Avista Corporation Non-Employee Director Compensation.
12	[2]		Statement Re: computation of ratio of earnings to fixed charges.
21	[2]		Subsidiaries of Registrant.
23	[2]		Consent of Independent Registered Public Accounting Firm.
31.1	[2]		Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002).
31.2	[2]		Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002).

Exhibit	With Registration Number	Previously Filed [1] As Exhibit	
32	[4]		Certification of Corporate Officers (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002).
101	[2]		The following financial information from the Annual Report on Form 10-K for the period ended December 31, 2017, formatted in XBRL (Extensible Business Reporting Language) and filed electronically herewith: (i) the Consolidated Statements of Income; (ii) Consolidated Statements of Comprehensive Income; (iii) the Consolidated Balance Sheets; (iv) the Consolidated Statements of Cash Flows; (v) the Consolidated Statements of Equity; and (vi) the Notes to Consolidated Financial Statements.

(1) Incorporated herein by reference.

(2) Filed herewith.

(3) Management contracts or compensatory plans filed as exhibits to this Form 10-K pursuant to Item 15(b).

(4) Furnished herewith.

(5) Applies to Marian M. Durkin, Karen S. Feltes, James M. Kensok, Scott L. Morris, Jason R. Thackston, Mark T. Thies and Dennis P. Vermillion.

(6) Applies to Kevin J. Christie, Ryan L. Krasselt and Heather L. Rosentrater.

(7) Applies to Edward D. Schlect.

(8) Applies to James M. Kensok, David J. Meyer, Jason R. Thackston and Dennis P. Vermillion.

(9) Applies to Marian M. Durkin, Karen S. Feltes, Scott L. Morris, and Mark T. Thies.

(10) Applies to Kevin J. Christie, Ryan L. Krasselt, Heather L. Rosentrater and Edward D. Schlect.

(11) This agreement currently does not apply to any executives; however, it could apply to any new Senior Vice Presidents appointed after November 13, 2009 if they chose to be under this agreement.

EXHIBIT 12

Avista Corporation

Computation of Ratio of Earnings to Fixed Charges

Consolidated

(Thousands of Dollars)

Years Ended December 31,

	2017	2016	2015	2014	2013
Fixed charges, as defined:					
Interest charges	$ 96,067	$ 86,897	$ 80,613	$ 74,025	$ 73,772
Amortization of debt expense and premium—net	3,167	3,391	3,415	3,635	3,813
Interest portion of rentals	1,160	1,324	1,287	1,187	1,146
Total fixed charges	$ 100,394	$ 91,612	$ 85,315	$ 78,847	$ 78,731
Earnings, as defined:					
Pre-tax income from continuing operations	$ 198,690	$ 215,402	$ 185,619	$ 192,106	$ 162,347
Add (deduct):					
Capitalized interest	(3,310)	(2,651)	(3,546)	(3,924)	(3,676)
Total fixed charges above	100,394	91,612	85,315	78,847	78,731
Total earnings	$ 295,774	$ 304,363	$ 267,388	$ 267,029	$ 237,402
Ratio of earnings to fixed charges	2.95	3.32	3.13	3.39	3.02

EXHIBIT 21

Avista Corporation

SUBSIDIARIES OF REGISTRANT

Subsidiary	State or Country of Incorporation
Avista Capital, Inc.	Washington
Avista Development, Inc.	Washington
Avista Energy, Inc.	Washington
Avista Northwest Resources, LLC	Washington
Pentzer Corporation	Washington
Pentzer Venture Holding II, Inc.	Washington
Bay Area Manufacturing, Inc.	Washington
Advanced Manufacturing and Development, Inc.	California
Avista Capital II	Delaware
Steam Plant Square, LLC	Washington
Steam Plant Brew Pub, LLC	Washington
Courtyard Office Center, LLC	Washington
Alaska Energy and Resources Company	Alaska
Alaska Electric Light and Power Company	Alaska
AJT Mining Properties, Inc.	Alaska
Snettisham Electric Company	Alaska
Salix, Inc.	Washington

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-33790, 333-126577, 333-179042 and 333-208986 on Form S8 and in Registration Statement No. 333-209714 on Form S-3, relating to the consolidated financial statements of Avista Corporation and subsidiaries, and the effectiveness of Avista Corporation's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Avista Corporation for the year ended December 31, 2017.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 20, 2018

EXHIBIT 31.1

CERTIFICATION

I, Scott L. Morris, certify that:

1. I have reviewed this report on Form 10-K of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/ Scott L. Morris
Scott L. Morris
Chairman of the Board
and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.2

CERTIFICATION

I, Mark T. Thies, certify that:

1. I have reviewed this report on Form 10-K of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/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 and Chief Executive Officer of Avista Corporation (the "Company"), and Mark T. Thies, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company's Annual Report on Form 10-K for the year ended December 31, 2017 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 20, 2018

/s/ Scott L. Morris
Scott L. Morris
Chairman of the Board and Chief Executive Officer

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

SELECTED FINANCIAL DATA

Avista Corporation

As of and for the years ended December 31,

Dollars in thousands, except per share data and ratios

	2017	2016	2015	2014	2013	2007
FINANCIAL RESULTS						
Operating revenues	$ 1,445,929	$ 1,442,483	$ 1,484,776	$ 1,472,562	$ 1,441,744	$ 1,370,502
Operating expenses	1,161,420	1,152,680	1,231,562	1,219,974	1,210,655	1,243,085
Income from continuing operations	284,509	289,803	253,214	252,588	231,089	127,417
Interest expense	96,192	87,130	80,441	75,752	77,585	86,246
Income taxes	82,758	78,086	67,449	72,240	58,014	20,392
Net income from continuing operations	115,932	137,316	118,170	119,866	104,333	32,076
Net income (loss) from discontinued operations	—	—	5,147	72,411	7,961	6,651
Net income	115,932	137,316	123,317	192,277	112,294	38,727
Net income attributable to noncontrolling interests	(16)	(88)	(90)	(236)	(1,217)	(252)
Net income attributable to Avista Corp. shareholders:						
Net income from continuing operations attributable to Avista Corp. shareholders	$ 115,916	$ 137,228	$ 118,080	$ 119,817	$ 104,273	$ 31,824
Net income from discontinued operations attributable to Avista Corp. shareholders	$ —	$ —	$ 5,147	$ 72,224	$ 6,804	$ 6,651
Net income attributable to Avista Corp. shareholders	$ 115,916	$ 137,228	$ 123,227	$ 192,041	$ 111,077	$ 38,475
Earnings per common share attributable to Avista Corp. shareholders—diluted:						
Earnings from continuing operations	1.79	2.15	1.89	1.93	1.74	0.60
Earnings from discontinued operations	—	—	0.08	1.17	0.11	0.12
Total	1.79	2.15	1.97	3.10	1.85	0.72
Earnings per common share attributable to Avista Corp. shareholders—basic:	1.80	2.16	1.98	3.12	1.85	0.73
COMMON STOCK STATISTICS						
Dividends paid per common share	$ 1.43	$ 1.37	$ 1.32	$ 1.27	$ 1.22	$ 0.595
Book value per common share	$ 26.41	$ 25.69	$ 24.53	$ 23.84	$ 21.61	$ 17.27
Shares of common stock:						
Outstanding at year-end	65,494	64,188	62,313	62,243	60,077	52,909
Average—basic	64,496	63,508	62,301	61,632	59,960	52,796
Average—diluted	64,806	63,920	62,708	61,887	59,997	52,263
Return on average Avista Corp. stockholders' equity:						
Total company	6.9%	8.6%	8.2%	13.7%	8.7%	4.2%
Utility only	7.5%	9.2%	8.4%	9.0%	9.3%	5.8%
Non-utility only	0.7%	3.0%	6.5%	54.4%	2.2%	(3.4)%
Common stock price:						
High	$ 52.74	$ 44.97	$ 38.30	$ 37.37	$ 29.26	$ 25.81
Low	$ 37.94	$ 34.67	$ 29.93	$ 27.71	$ 24.10	$ 18.19
Year-end close	$ 51.49	$ 39.99	$ 35.37	$ 35.35	$ 28.19	$ 21.54
DEBT STATISTICS						
Pre-tax interest coverage:						
Including AFUDC/AFUCE	3.11(x)	3.54(x)	3.46(x)	4.52(x)	3.27(x)	1.75(x)
Excluding AFUDC/AFUCE	3.00(x)	3.43(x)	3.31(x)	4.35(x)	3.14(x)	1.65(x)
Embedded cost of long-term debt	5.58%	5.55%	5.31%	5.37%	5.53%	7.84%

Avista Corporation

As of and for the years ended December 31,

Dollars in thousands, except per share data and ratios

	2017	2016	2015	2014	2013	2007
FINANCIAL CONDITION						
Total assets [1] [2]	$ 5,529,807	$ 5,309,755	$ 4,906,649	$ 4,700,971	$ 4,011,533	$ 3,070,479
Total net Avista Utilities property	4,196,691	3,943,087	3,702,691	3,427,641	3,202,425	2,351,342
Avista Utilities property capital expenditures (excluding equity-related AFUDC)	405,938	390,690	381,174	323,931	294,363	205,811
Long-term debt (including current portion) [2]	1,769,237	1,682,004	1,573,278	1,487,126	1,262,036	938,444
Nonrecourse long-term debt of Spokane Energy (including current portion)	—	—	—	1,431	17,838	—
Long-term debt to affiliated trusts	51,547	51,547	51,547	51,547	51,547	113,403
Avista Corporation stockholders' equity	$ 1,729,828	$ 1,648,727	$ 1,528,626	$ 1,483,671	$ 1,298,266	$ 913,966
AVISTA UTILITIES						
Electric Operations						
Electric operating revenues (millions of dollars):						
Residential	$ 381.7	$ 339.2	$ 335.5	$ 338.7	$ 331.9	$ 251.4
Commercial	311.6	305.6	308.2	300.1	289.6	224.2
Industrial	111.0	107.3	111.8	110.8	113.6	95.2
Public street and highway lighting	7.5	7.7	7.3	7.5	7.3	5.5
Total retail	811.8	759.8	762.8	757.1	742.4	576.3
Wholesale	81.5	112.1	127.3	138.2	127.5	105.7
Sales of fuel	64.9	78.3	82.9	83.7	126.7	12.9
Other	31.6	28.5	25.8	27.5	36.0	16.2
Decoupling	(8.2)	17.4	4.7	—	—	—
Provision for earning sharing	(1.2)	0.9	(5.6)	(7.5)	(2.0)	—
Total electric operating revenues	$ 980.4	$ 997.0	$ 997.9	$ 999.0	$ 1,030.6	$ 711.1
Electric energy sales (millions of kWhs):						
Residential	3,840	3,528	3,571	3,694	3,745	3,670
Commercial	3,222	3,183	3,197	3,189	3,147	3,132
Industrial	1,815	1,763	1,812	1,868	1,979	2,084
Public street and highway lighting	20	23	23	25	26	26
Total retail	8,897	8,497	8,603	8,776	8,897	8,912
Wholesale	2,881	2,998	3,145	3,686	3,874	1,594
Total electric energy sales	11,778	11,495	11,748	12,462	12,771	10,506
Retail electric customers (average per year):						
Residential	334,848	330,699	327,057	324,188	321,098	306,737
Commercial	42,154	41,785	41,296	40,988	40,202	38,488
Industrial	1,328	1,342	1,353	1,385	1,386	1,378
Public street and highway lighting	569	558	529	531	527	426
Total retail electric customers	378,899	374,384	370,235	367,092	363,213	347,029

(1) The total assets at year-end for the years 2013 and 2007 exclude the total assets associated with Ecova of $339.6 million and $108.9 million, respectively.

(2) The total assets and total long-term debt and capital leases for 2014, 2013 and 2007 were adjusted in accordance with a change in accounting standards.

Avista Corporation

As of and for the years ended December 31,

	2017	2016	2015	2014	2013	2007
Electric Operations (continued)						
Retail electric customers (at year-end):						
Residential	337,936	333,346	330,749	326,917	323,801	310,701
Commercial	42,280	41,921	42,182	41,264	40,492	39,001
Industrial	1,320	1,328	1,362	1,378	1,382	1,383
Public street and highway lighting	595	564	555	527	531	427
Total retail electric customers	382,131	377,159	374,848	370,086	366,206	351,512
Revenue per residential kWh (cents)	9.94	9.62	9.40	9.17	8.86	6.85
Use per residential customer (kWh)	11,469	10,667	10,827	11,394	11,664	11,965
Revenue per commercial kWh (cents)	9.67	9.60	9.64	9.41	9.20	7.16
Use per commercial customer (kWh)	76,444	76,166	76,638	77,814	78,276	81,377
Electric energy resources (millions of kWhs):						
Hydro generation (from Company facilities)	3,978	3,836	3,434	4,143	3,646	3,689
Thermal generation (from Company facilities)	3,476	3,626	3,983	3,252	3,383	3,640
Purchased power	4,809	4,597	4,899	5,615	6,375	3,820
Power exchanges	(6)	(6)	(2)	(25)	(20)	(18)
Total power resources	12,257	12,053	12,314	12,985	13,384	11,131
Energy losses and company use	(479)	(558)	(566)	(523)	(613)	(625)
Total electric energy resources	11,778	11,495	11,748	12,462	12,771	10,506
Retail Native Load at time of system peak						
Winter	1,681	1,655	1,529	1,715	1,669	1,685
Summer	1,596	1,587	1,638	1,606	1,577	1,631
Natural Gas Operations						
Natural gas operating revenues (millions of dollars):						
Residential	$ 220.2	$ 195.3	$ 193.8	$ 203.4	$ 206.3	$ 264.5
Commercial	104.2	93.0	96.8	103.2	102.2	148.4
Industrial and interruptible	5.7	5.5	6.5	6.9	6.3	11.3
Total retail	330.1	293.8	297.1	313.5	314.8	424.2
Wholesale	142.7	153.5	204.3	228.2	194.7	142.2
Transportation	9.2	8.3	8.0	7.7	7.6	6.6
Other	6.4	5.8	5.6	7.5	8.6	4.2
Decoupling	(11.4)	12.3	6.0	—	—	—
Provision for earning sharing	(2.4)	(2.8)	—	(0.2)	(0.4)	—
Total natural gas operating revenues	$ 474.6	$ 470.9	$ 521.0	$ 556.7	$ 525.3	$ 577.2
Natural gas therms delivered (millions of therms):						
Residential	222.0	186.6	176.6	190.2	204.7	195.7
Commercial	133.3	112.7	107.9	116.7	122.2	121.6
Industrial and interruptible	11.8	10.9	9.8	10.7	10.9	10.8
Total retail	367.1	310.2	294.3	317.6	337.8	328.1
Wholesale	545.3	684.3	809.1	545.6	524.8	223.1
Transportation and other	186.7	178.8	165.0	162.7	160.4	149.2
Total natural gas therms delivered	1,099.1	1,173.3	1,268.4	1,025.9	1,023.0	700.4

Avista Corporation

As of and for the years ended December 31,

	2017	2016	2015	2014	2013	2007
Natural Gas Operations (continued)						
Retail natural gas customers (average per year):						
Residential	307,375	300,883	296,005	291,928	288,708	273,415
Commercial	35,192	34,868	34,229	34,047	33,932	32,327
Industrial and interruptible	288	292	296	301	297	302
Total retail natural gas customers	342,855	336,043	330,530	326,276	322,937	306,044
Retail natural gas customers (at year-end):						
Residential	311,518	304,814	299,509	294,993	291,386	277,397
Commercial	35,353	35,032	34,775	34,267	34,084	32,840
Industrial and interruptible	289	285	289	304	287	298
Total retail natural gas customers	347,160	340,131	334,573	329,564	325,757	310,535
Revenue per residential therm (in dollars)	0.99	1.05	1.10	1.07	1.01	1.35
Use per residential customer (therms)	722	620	593	651	709	716
Revenue per commercial therm (in dollars)	0.78	0.83	0.90	0.88	0.84	1.22
Use per commercial customer (therms)	3,789	3,232	3,128	3,429	3,603	3,760
Heating degree days (at Spokane, Washington):						
Actual	6,783	5,790	5,614	6,215	6,683	6,539
30 year average	6,578	6,680	6,726	6,748	6,750	6,820
Actual as a percent of average	103%	87%	83%	92%	99%	96%
ALASKA ELECTRIC LIGHT AND POWER COMPANY						
Revenues (millions of dollars)	53.0	46.3	44.8	21.6	—	—
Total assets (millions of dollars)	278.7	273.8	265.7	263.1	—	—
ECOVA						
Revenues (millions of dollars)	$ —	$ —	$ —	$ 87.5	$ 176.8	$ 47.3
Total assets (millions of dollars)	$ —	$ —	$ —	$ —	$ 339.6	$ 108.9
OTHER						
Revenues (millions of dollars)	$ 22.5	$ 23.6	$ 28.7	$ 39.2	$ 39.5	$ 82.1
Total assets (millions of dollars)	$ 73.2	$ 60.4	$ 39.2	$ 80.1	$ 81.3	$ 71.4

CORPORATE INFORMATION

COMPANY HEADQUARTERS
Spokane, Washington

AVISTA ON THE INTERNET
Financial results, stock quotes, news releases, documents filed with the Securities and Exchange Commission (SEC), and information on the company's products and services are available on Avista's website at avistacorp.com.

DIRECT STOCK PURCHASE AND DIVIDEND REINVESTMENT PLAN
Computershare sponsors and administers the Computershare Investment Plan (CIP) for Avista Corp. common stock. To invest, obtain forms or for information about your holdings, please contact the transfer agent using the information below.

TRANSFER AGENT
Computershare
P.O. Box 30170
College Station, TX 77842-3170
800.642.7365
computershare.com/investor

INVESTOR INFORMATION
A copy of the company's financial reports, including the reports on Forms 10-K and 10-Q filed with the SEC, will be provided without charge upon request to:
Avista Corp.
Investor Relations
P.O. Box 3727 MSC-19
Spokane, WA 99220-3727
800.222.4931

ANNUAL MEETING OF SHAREHOLDERS
Shareholders are invited to attend the company's annual meeting to be held at 8:15 a.m. PDT on Thursday, May 10, 2018, at Avista Corp. headquarters, 1411 East Mission Avenue, Spokane, Washington.

The annual meeting will be webcast. Please go to avistacorp.com to preregister for the webcast and to listen to the live webcast. The webcast will be archived at avistacorp.com for one year to allow shareholders to listen at their convenience.

EXCHANGE LISTING
Ticker Symbol: AVA
New York Stock Exchange

CERTIFICATIONS
On May 16, 2017, the Chief Executive Officer (CEO) of Avista Corp. filed a Section 303A.12(a) Annual CEO Certification with the New York Stock Exchange. The CEO Certification attests that the CEO is not aware of any violations by the company of NYSE's Corporate Governance Listing Standards.

Avista Corp. has included as exhibits to its annual report on Form 10-K for the year 2017, filed with the SEC, certifications of Avista's Chief Executive Officer and Chief Financial Officer regarding the quality of Avista's public disclosure in compliance with Section 302 of the Sarbanes-Oxley Act of 2002.

This annual report contains forward-looking statements regarding the company's current expectations. These statements are subject to a variety of risks and uncertainties that could cause actual results to differ materially from the expectations. These risks and uncertainties include, in addition to those discussed herein, all factors discussed in the company's annual report on Form 10-K for the year 2017. Our 2017 annual report is provided for shareholders. It is not intended for use in connection with any sale or purchase of or any solicitation of others to buy or sell securities.

The 2017 annual report is produced through a partnership of Avista employees and companies within Avista's service area. Design, Copywriting and Production: Klündt | Hosmer; Photography: Dean Davis Photography, RL Miller Photography LLC, Ben Tobin; Printing: Lawton Printing Services

HELP US HELP THE ENVIRONMENT
Managing costs is a primary goal for Avista. You can help us meet this goal by agreeing to receive future annual reports and proxy statements electronically. This service saves on the costs of printing and mailing, provides timely delivery of information, and helps protect our environment by decreasing the need for paper, printing and mailing materials.

FOR MORE INFORMATION, PLEASE VISIT: AVISTACORP.COM

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